UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number	Exact name of registrants as specified in their charters	I.R.S. Employer Identification Number
001-08489	DOMINION ENERGY, INC.	54-1229715
000-55337	VIRGINIA ELECTRIC AND POWER COMPANY	54-0418825
001-37591	DOMINION ENERGY GAS HOLDINGS, LLC	46-3639580

VIRGINIA
(State or other jurisdiction of incorporation or organization)
120 TREDEGAR STREET
RICHMOND, VIRGINIA **23219**
(Address of principal executive offices) *(Zip Code)*
(804) 819-2000
(Registrants' telephone number)

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
DOMINION ENERGY, INC.	Common Stock, no par value	New York Stock Exchange
	2016 Series A 6.75% Corporate Units	New York Stock Exchange
	2016 Series A 5.25% Enhanced Junior Subordinated Notes	New York Stock Exchange
DOMINION ENERGY GAS HOLDINGS, LLC	2014 Series C 4.6% Senior Notes	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
VIRGINIA ELECTRIC AND POWER COMPANY
Common Stock, no par value
DOMINION ENERGY GAS HOLDINGS, LLC
Limited Liability Company Membership Interests

Indicate by check mark whether the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act.
Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Dominion Energy, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Energy Gas Holdings, LLC Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
Dominion Energy, Inc. ☐ Virginia Electric and Power Company ☒ Dominion Energy Gas Holdings, LLC ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Dominion Energy, Inc.

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐ Emerging growth company ☐

Virginia Electric and Power Company

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐ Emerging growth company ☐

Dominion Energy Gas Holdings, LLC

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act).
Dominion Energy, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Energy Gas Holdings, LLC Yes ☐ No ☒

The aggregate market value of Dominion Energy, Inc. common stock held by non-affiliates of Dominion Energy was approximately $48.1 billion based on the closing price of Dominion Energy's common stock as reported on the New York Stock Exchange as of the last day of Dominion Energy's most recently completed second fiscal quarter. Dominion Energy is the sole holder of Virginia Electric and Power Company common stock. At February 15, 2018, Dominion Energy had 651,524,668 shares of common stock outstanding and Virginia Power had 274,723 shares of common stock outstanding. Dominion Energy, Inc. holds all of the membership interests of Dominion Energy Gas Holdings, LLC.

DOCUMENT INCORPORATED BY REFERENCE.

Portions of Dominion Energy's 2018 Proxy Statement are incorporated by reference in Part III.

This combined Form 10-K represents separate filings by Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC make no representations as to the information relating to Dominion Energy, Inc.'s other operations.

VIRGINIA ELECTRIC AND POWER COMPANY AND DOMINION ENERGY GAS HOLDINGS, LLC MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K AND ARE FILING THIS FORM 10-K UNDER THE REDUCED DISCLOSURE FORMAT.

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Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC

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Glossary of Terms

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
2013 Equity Units	Dominion Energy's 2013 Series A Equity Units and 2013 Series B Equity Units issued in June 2013
2014 Equity Units	Dominion Energy's 2014 Series A Equity Units issued in July 2014
2015 Biennial Review Order	Order issued by the Virginia Commission in November 2015 concluding the 2013—2014 biennial review of Virginia Power's base rates, terms and conditions
2016 Equity Units	Dominion Energy's 2016 Series A Equity Units issued in August 2016
2017 Tax Reform Act	An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (previously known as The Tax Cuts and Jobs Act) enacted on December 22, 2017
2018 Proxy Statement	Dominion Energy 2018 Proxy Statement, File No. 001-08489
ABO	Accumulated benefit obligation
AFUDC	Allowance for funds used during construction
AMI	Advanced Metering Infrastructure
AMR	Automated meter reading program deployed by East Ohio
AOCI	Accumulated other comprehensive income (loss)
APCo	Appalachian Power Company
ARO	Asset retirement obligation
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC, a limited liability company owned by Dominion Energy, Duke and Southern Company Gas
Atlantic Coast Pipeline Project	The approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina which will be owned by Dominion Energy, Duke and Southern Company Gas and constructed and operated by DETI
BACT	Best available control technology
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
Bear Garden	A 590 MW combined cycle, natural gas-fired power station in Buckingham County, Virginia
BGEPA	Bald and Golden Eagle Protection Act
Blue Racer	Blue Racer Midstream, LLC, a joint venture between Dominion Energy and Caiman
BP	BP Wind Energy North America Inc.
Brayton Point	Brayton Point power station
BREDL	Blue Ridge Environmental Defense League
Brunswick County	A 1,376 MW combined cycle, natural gas-fired power station in Brunswick County, Virginia
CAA	Clean Air Act
Caiman	Caiman Energy II, LLC
CAISO	California ISO
CAO	Chief Accounting Officer
CCR	Coal combustion residual
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as Superfund
CFO	Chief Financial Officer
CGN Committee	Compensation, Governance and Nominating Committee of Dominion Energy's Board of Directors
Clean Power Plan	Regulations issued by the EPA in August 2015 for states to follow in developing plans to reduce CO_2 emissions from existing fossil fuel-fired electric generating units, stayed by the U.S. Supreme Court in February 2016 pending resolution of court challenges by certain states
CNG	Consolidated Natural Gas Company
CO_2	Carbon dioxide
COL	Combined Construction Permit and Operating License
Companies	Dominion Energy, Virginia Power and Dominion Energy Gas, collectively
COO	Chief Operating Officer
Cooling degree days	Units measuring the extent to which the average daily temperature is greater than 65 degrees Fahrenheit, calculated as the difference between 65 degrees and the average temperature for that day
Corporate Unit	A stock purchase contract and 1/20 or 1/40 interest in a RSN issued by Dominion Energy
Cove Point	Dominion Energy Cove Point LNG, LP
Cove Point Holdings	Cove Point GP Holding Company, LLC
CPCN	Certificate of Public Convenience and Necessity
CWA	Clean Water Act
DECG	Dominion Energy Carolina Gas Transmission, LLC
DES	Dominion Energy Services, Inc.
DETI	Dominion Energy Transmission, Inc.
DGI	Dominion Generation, Inc.

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Abbreviation or Acronym	Definition
DGP	Dominion Gathering and Processing, Inc.
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
DOE	U.S. Department of Energy
Dominion Energy	The legal entity, Dominion Energy, Inc., one or more of its consolidated subsidiaries (other than Virginia Power and Dominion Energy Gas) or operating segments, or the entirety of Dominion Energy, Inc. and its consolidated subsidiaries
Dominion Energy Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion Energy Gas	The legal entity, Dominion Energy Gas Holdings, LLC, one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Energy Gas Holdings, LLC and its consolidated subsidiaries
Dominion Energy Midstream	The legal entity, Dominion Energy Midstream Partners, LP, one or more of its consolidated subsidiaries, Cove Point Holdings, Iroquois GP Holding Company, LLC, DECG and Dominion Energy Questar Pipeline (beginning December 1, 2016) or operating segment, or the entirety of Dominion Energy Midstream Partners, LP and its consolidated subsidiaries
Dominion Energy Questar	The legal entity, Dominion Energy Questar Corporation, one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Energy Questar Corporation and its consolidated subsidiaries
Dominion Energy Questar Combination	Dominion Energy's acquisition of Dominion Energy Questar completed on September 16, 2016 pursuant to the terms of the agreement and plan of merger entered on January 31, 2016
Dominion Energy Questar Pipeline	Dominion Energy Questar Pipeline, LLC (formerly known as Questar Pipeline, LLC), one or more of its consolidated subsidiaries, or the entirety of Dominion Energy Questar Pipeline, LLC and its consolidated subsidiaries
Dominion Iroquois	Dominion Iroquois, Inc., which, effective May 2016, holds a 24.07% noncontrolling partnership interest in Iroquois
DSM	Demand-side management
Dth	Dekatherm
Duke	The legal entity, Duke Energy Corporation, one or more of its consolidated subsidiaries or operating segments, or the entirety of Duke Energy Corporation and its consolidated subsidiaries
East Ohio	The East Ohio Gas Company, doing business as Dominion Energy Ohio
Eastern Market Access Project	Project to provide 294,000 Dths/day of firm transportation service to help meet demand for natural gas for Washington Gas Light Company, a local gas utility serving customers in D.C., Virginia and Maryland, and Mattawoman Energy, LLC for its new electric power generation facility to be built in Maryland
Elwood	Elwood power station
Energy Choice	Program authorized by the Ohio Commission which provides energy customers with the ability to shop for energy options from a group of suppliers certified by the Ohio Commission
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPS	Earnings per share
ERISA	Employee Retirement Income Security Act of 1974
ERM	Enterprise Risk Management
ERO	Electric Reliability Organization
ESA	Endangered Species Act
Excess Tax Benefits	Benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Ltd.
Four Brothers	Four Brothers Solar, LLC, a limited liability company owned by Dominion Energy and Four Brothers Holdings, LLC, a wholly-owned subsidiary of NRG effective November 2016
Fowler Ridge	Fowler I Holdings LLC, a wind-turbine facility joint venture with BP in Benton County, Indiana
FTA	Free Trade Agreement
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
Gas Infrastructure	Gas Infrastructure Group operating segment
GHG	Greenhouse gas
Granite Mountain	Granite Mountain Holdings, LLC, a limited liability company owned by Dominion Energy and Granite Mountain Renewables, LLC, a wholly-owned subsidiary of NRG effective November 2016
Green Mountain	Green Mountain Power Corporation
Greensville County	An approximately 1,588 MW natural gas-fired combined-cycle power station under construction in Greensville County, Virginia
Hastings	A natural gas processing and fractionation facility located near Pine Grove, West Virginia
HATFA of 2014	Highway and Transportation Funding Act of 2014

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Abbreviation or Acronym	Definition
Heating degree days	Units measuring the extent to which the average daily temperature is less than 65 degrees Fahrenheit, calculated as the difference between 65 degrees and the average temperature for that day
Hope	Hope Gas, Inc., doing business as Dominion Energy West Virginia
Idaho Commission	Idaho Public Utilities Commission
IRCA	Intercompany revolving credit agreement
Iron Springs	Iron Springs Holdings, LLC, a limited liability company owned by Dominion Energy and Iron Springs Renewables, LLC, a wholly-owned subsidiary of NRG effective November 2016
Iroquois	Iroquois Gas Transmission System, L.P.
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England
July 2016 hybrids	Dominion Energy's 2016 Series A Enhanced Junior Subordinated Notes due 2076
June 2006 hybrids	Dominion Energy's 2006 Series A Enhanced Junior Subordinated Notes due 2066
Kewaunee	Kewaunee nuclear power station
Kincaid	Kincaid power station
kV	Kilovolt
Liability Management Exercise	Dominion Energy exercise in 2014 to redeem certain debt and preferred securities
LIBOR	London Interbank Offered Rate
LIFO	Last-in-first-out inventory method
Line TL-388	A 37-mile, 24-inch gathering pipeline extending from Texas Eastern, LP in Noble County, Ohio to its terminus at Dominion Energy's Gilmore Station in Tuscarawas County, Ohio
Liquefaction Project	A natural gas export/liquefaction facility at Cove Point
LNG	Liquefied natural gas
Local 50	International Brotherhood of Electrical Workers Local 50
Local 69	Local 69, Utility Workers Union of America, United Gas Workers
LTIP	Long-term incentive program
MAP 21 Act	Moving Ahead for Progress in the 21st Century Act
Massachusetts Municipal	Massachusetts Municipal Wholesale Electric Company
MATS	Utility Mercury and Air Toxics Standard Rule
MBTA	Migratory Bird Treaty Act of 1918
mcf	Thousand cubic feet
mcfe	Thousand cubic feet equivalent
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MGD	Million gallons a day
Millstone	Millstone nuclear power station
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master limited partnership, also known as publicly traded partnership
Moody's	Moody's Investors Service
Morgans Corner	Morgans Corner Solar Energy, LLC
MW	Megawatt
MWh	Megawatt hour
NAV	Net asset value
NedPower	NedPower Mount Storm LLC, a wind-turbine facility joint venture between Dominion Energy and Shell in Grant County, West Virginia
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquid
NJNR	NJNR Pipeline Company
North Anna	North Anna nuclear power station
North Carolina Commission	North Carolina Utilities Commission
Northern System	Collection of approximately 131 miles of various diameter natural gas pipelines in Ohio
NOx	Nitrogen oxide
NRC	Nuclear Regulatory Commission
NRG	The legal entity, NRG Energy, Inc., one or more of its consolidated subsidiaries (including, effective November 2016, Four Brothers Holdings, LLC, Granite Mountain Renewables, LLC and Iron Springs Renewables, LLC) or operating segments, or the entirety of NRG Energy, Inc. and its consolidated subsidiaries
NSPS	New Source Performance Standards
NYSE	New York Stock Exchange
October 2014 hybrids	Dominion Energy's 2014 Series A Enhanced Junior Subordinated Notes due 2054

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Abbreviation or Acronym	Definition
ODEC	Old Dominion Electric Cooperative
Ohio Commission	Public Utilities Commission of Ohio
Order 1000	Order issued by FERC adopting new requirements for electric transmission planning, cost allocation and development
Philadelphia Utility Index	Philadelphia Stock Exchange Utility Index
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPP	Percentage of Income Payment Plan deployed by East Ohio
PIR	Pipeline Infrastructure Replacement program deployed by East Ohio
PJM	PJM Interconnection, L.L.C.
Power Delivery	Power Delivery Group operating segment
Power Generation	Power Generation Group operating segment
ppb	Parts-per-billion
PREP	Pipeline Replacement and Expansion Program, a program of replacing, upgrading and expanding natural gas utility infrastructure deployed by Hope
PSMP	Pipeline Safety Management Program deployed by East Ohio to ensure the continued safe and reliable operation of East Ohio's system and compliance with pipeline safety laws
PSD	Prevention of significant deterioration
Questar Gas	Questar Gas Company
RCC	Replacement Capital Covenant
Regulation Act	Legislation effective July 1, 2007, that amended the Virginia Electric Utility Restructuring Act and fuel factor statute, which legislation is also known as the Virginia Electric Utility Regulation Act, as amended in 2015
RGGI	Regional Greenhouse Gas Initiative
Rider B	A rate adjustment clause associated with the recovery of costs related to the conversion of three of Virginia Power's coal-fired power stations to biomass
Rider BW	A rate adjustment clause associated with the recovery of costs related to Brunswick County
Rider GV	A rate adjustment clause associated with the recovery of costs related to Greensville County
Rider R	A rate adjustment clause associated with the recovery of costs related to Bear Garden
Rider S	A rate adjustment clause associated with the recovery of costs related to the Virginia City Hybrid Energy Center
Rider T1	A rate adjustment clause to recover the difference between revenues produced from transmission rates included in base rates, and the new total revenue requirement developed annually for the rate years effective September 1
Rider U	A rate adjustment clause associated with the recovery of costs of new underground distribution facilities
Rider US-2	A rate adjustment clause associated with Woodland, Scott Solar and Whitehouse
Rider W	A rate adjustment clause associated with the recovery of costs related to Warren County
Riders C1A and C2A	Rate adjustment clauses associated with the recovery of costs related to certain DSM programs approved in DSM cases
ROE	Return on equity
ROIC	Return on invested capital
RSN	Remarketable subordinated note
RTEP	Regional transmission expansion plan
RTO	Regional transmission organization
SAFSTOR	A method of nuclear decommissioning, as defined by the NRC, in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated to levels that permit release for unrestricted use
SAIDI	System Average Interruption Duration Index, metric used to measure electric service reliability
SBL Holdco	SBL Holdco, LLC, a wholly-owned subsidiary of DGI
SCANA	The legal entity, SCANA Corporation, one or more of its consolidated subsidiaries, or operating segments, or the entirety of SCANA Corporation and its consolidated subsidiaries
SCANA Merger Agreement	Agreement and plan of merger entered on January 2, 2018 between Dominion Energy and SCANA in which SCANA will become a wholly-owned subsidiary of Dominion Energy upon closing
SCE&G	South Carolina Electric & Gas Company, a wholly-owned subsidiary of SCANA
Scott Solar	A 17 MW utility-scale solar power station in Powhatan County, VA
SEC	Securities and Exchange Commission
September 2006 hybrids	Dominion Energy's 2006 Series B Enhanced Junior Subordinated Notes due 2066
Shell	Shell WindEnergy, Inc.
SO_2	Sulfur dioxide
South Carolina Commission	South Carolina Public Service Commission
Standard & Poor's	Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc.

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Abbreviation or Acronym	Definition
SunEdison	The legal entity, SunEdison, Inc., one or more of its consolidated subsidiaries (including, through November 2016, Four Brothers Holdings, LLC, Granite Mountain Renewables, LLC and Iron Springs Renewables, LLC) or operating segments, or the entirety of SunEdison, Inc. and its consolidated subsidiaries
Surry	Surry nuclear power station
Terra Nova Renewable Partners	A partnership comprised primarily of institutional investors advised by J.P. Morgan Asset Management—Global Real Assets
Three Cedars	Granite Mountain and Iron Springs, collectively
TransCanada	The legal entity, TransCanada Corporation, one or more of its consolidated subsidiaries or operating segments, or the entirety of TransCanada Corporation and its consolidated subsidiaries
TSR	Total shareholder return
UEX Rider	Uncollectible Expense Rider deployed by East Ohio
Utah Commission	Public Service Commission of Utah
VDEQ	Virginia Department of Environmental Quality
VEBA	Voluntary Employees' Beneficiary Association
VIE	Variable interest entity
Virginia City Hybrid Energy Center	A 610 MW baseload carbon-capture compatible, clean coal powered electric generation facility in Wise County, Virginia
Virginia Commission	Virginia State Corporation Commission
Virginia Power	The legal entity, Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries
VOC	Volatile organic compounds
Warren County	A 1,350 MW combined-cycle, natural gas-fired power station in Warren County, Virginia
West Virginia Commission	Public Service Commission of West Virginia
Western System	Collection of approximately 212 miles of various diameter natural gas pipelines and three compressor stations in Ohio
Wexpro	The legal entity, Wexpro Company, one or more of its consolidated subsidiaries, or the entirety of Wexpro Company and its consolidated subsidiaries
Wexpro Agreement	An agreement effective August 1981, which sets forth the rights of Questar Gas to receive certain benefits from Wexpro's operations, including cost-of-service gas
Wexpro II Agreement	An agreement with the states of Utah and Wyoming modeled after the Wexpro Agreement that allows for the addition of properties under the cost-of-service methodology for the benefit of Questar Gas customers
Whitehouse	A 20 MW utility-scale solar power station in Louisa County, VA
White River Hub	White River Hub, LLC
Woodland	A 19 MW utility-scale solar power station in Isle of Wight County, VA
Wyoming Commission	Wyoming Public Service Commission

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Part I

Item 1. Business

GENERAL

Dominion Energy, headquartered in Richmond, Virginia and incorporated in Virginia in 1983, is one of the nation's largest producers and transporters of energy. Dominion Energy's strategy is to be a leading provider of electricity, natural gas and related services to customers primarily in the eastern and Rocky Mountain regions of the U.S. As of December 31, 2017, Dominion Energy's portfolio of assets includes approximately 26,000 MW of generating capacity, 6,600 miles of electric transmission lines, 57,900 miles of electric distribution lines, 14,800 miles of natural gas transmission, gathering and storage pipelines and 51,800 miles of gas distribution pipeline, exclusive of service lines. As of December 31, 2017, Dominion Energy serves nearly 6 million utility and retail energy customers and operates one of the nation's largest underground natural gas storage systems, with approximately 1 trillion cubic feet of storage capacity.

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination for total consideration of $4.4 billion and Dominion Energy Questar, a Rockies-based integrated natural gas company, became a wholly-owned subsidiary of Dominion Energy. Questar Gas, a wholly-owned subsidiary of Dominion Energy Questar, is consolidated by Dominion Energy, and is a voluntary SEC filer. However, its Form 10-K is filed separately and is not combined herein.

In March 2014, Dominion Energy formed Dominion Energy Midstream, an MLP designed to grow a portfolio of natural gas terminaling, processing, storage, transportation and related assets. In October 2014, Dominion Energy Midstream launched its initial public offering and issued 20,125,000 common units representing limited partner interests. Dominion Energy has and may continue to investigate opportunities to acquire assets that meet its strategic objective for Dominion Energy Midstream. At December 31, 2017, Dominion Energy owns the general partner, 50.6% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Energy Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DECG, Dominion Energy Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. Dominion Energy Midstream is consolidated by Dominion Energy, and is an SEC registrant. However, its Form 10-K is filed separately and is not combined herein.

Dominion Energy is focused on expanding its investment in regulated electric generation, transmission and distribution and regulated natural gas transmission and distribution infrastructure. Dominion Energy expects approximately 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

Dominion Energy continues to expand and improve its regulated and long-term contracted electric and natural gas businesses, in accordance with its existing five-year capital investment program. A major impetus for this program is to meet the anticipated increase in demand in its electric utility service territory. Other drivers for the capital investment program include the construction of infrastructure to handle the increase in natural gas production from the Marcellus and Utica Shale formations, to upgrade Dominion Energy's gas and electric transmission and distribution networks, and to meet environmental requirements and standards set by various regulatory bodies. Investments in utility-scale solar generation are expected to be a focus in meeting such environmental requirements, particularly in Virginia. In September 2014, Dominion Energy announced the formation of Atlantic Coast Pipeline. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina, to increase natural gas supplies in the region.

Dominion Energy has transitioned over the past decade to a more regulated, less volatile earnings mix as evidenced by its capital investments in regulated infrastructure, including the Dominion Energy Questar Combination, and in infrastructure whose output is sold under long-term purchase agreements as well as the sale of the electric retail energy marketing business in March 2014. Dominion Energy's nonregulated operations include merchant generation, energy marketing and price risk management activities and natural gas retail energy marketing operations. Dominion Energy's operations are conducted through various subsidiaries, including Virginia Power and Dominion Energy Gas.

Virginia Power, headquartered in Richmond, Virginia and incorporated in Virginia in 1909 as a Virginia public service corporation, is a wholly-owned subsidiary of Dominion Energy and a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and North Carolina. In Virginia, Virginia Power conducts business under the name "Dominion Energy Virginia" and primarily serves retail customers. In North Carolina, it conducts business under the name "Dominion Energy North Carolina" and serves retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, Virginia Power sells electricity at wholesale prices to rural electric cooperatives, municipalities and into wholesale electricity markets. All of Virginia Power's stock is owned by Dominion Energy.

Dominion Energy Gas, a limited liability company formed in September 2013, is a wholly-owned subsidiary of Dominion Energy and a holding company. It serves as the intermediate parent company for certain of Dominion Energy's regulated natural gas operating subsidiaries, which conduct business activities through a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, regulated gas transportation and distribution operations in Ohio, and gas gathering and processing activities primarily in West Virginia, Ohio and Pennsylvania. Dominion Energy Gas' principal wholly-owned subsidiaries are DETI, East Ohio, DGP and Dominion Iroquois. DETI is an interstate natural gas transmission pipeline company serving a broad mix of customers such as local gas distribution companies, marketers, interstate and intrastate pipelines, electric power generators and natural gas producers. The DETI system links to other major pipelines and markets in the mid-Atlantic, Northeast, and Midwest including Dominion Energy's Cove Point pipeline. DETI also operates one of the largest underground natural gas storage systems in the U.S. In August 2016, DETI transferred its gathering and processing facilities to DGP. East Ohio is a regulated natural gas distribution operation serving residential, commercial and industrial gas sales and transportation customers. Its service territory includes Cleveland, Akron, Canton, Youngstown and other eastern and western Ohio communities. In May 2016,

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Dominion Energy Gas sold 0.65% of the noncontrolling partnership interest in Iroquois, a FERC-regulated interstate natural gas pipeline in New York and Connecticut, to TransCanada. At December 31, 2017, Dominion Energy Gas holds a 24.07% noncontrolling partnership interest in Iroquois. All of Dominion Energy Gas' membership interests are owned by Dominion Energy.

Amounts and information disclosed for Dominion Energy are inclusive of Virginia Power and/or Dominion Energy Gas, where applicable.

EMPLOYEES

At December 31, 2017, Dominion Energy had approximately 16,200 full-time employees, of which approximately 5,200 are subject to collective bargaining agreements. At December 31, 2017, Virginia Power had approximately 6,900 full-time employees, of which approximately 3,100 are subject to collective bargaining agreements. At December 31, 2017, Dominion Energy Gas had approximately 3,000 full-time employees, of which approximately 2,100 are subject to collective bargaining agreements.

WHERE YOU CAN FIND MORE INFORMATION ABOUT THE COMPANIES

The Companies file their annual, quarterly and current reports, proxy statements and other information with the SEC. Their SEC filings are available to the public over the Internet at the SEC's website at http://www.sec.gov. You may also read and copy any document they file at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

The Companies make their SEC filings available, free of charge, including the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports, through Dominion Energy's internet website, http://www.dominionenergy.com, as soon as reasonably practicable after filing or furnishing the material to the SEC. Information contained on Dominion Energy's website is not incorporated by reference in this report.

ACQUISITIONS AND DISPOSITIONS

The following are significant acquisitions and divestitures by the Companies during the last five years.

PROPOSED ACQUISITION OF SCANA

Under the terms of the SCANA Merger Agreement announced in January 2018, Dominion Energy has agreed to issue 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock upon closing. In addition, Dominion Energy will provide the financial support for SCE&G to make a $1.3 billion up-front, one-time rate credit to all current electric service customers of SCE&G to be paid within 90 days of closing and a $575 million refund along with the benefit of the 2017 Tax Reform Act resulting in at least a 5% reduction to SCE&G electric service customers' bills over an estimated eight-year period as well as the exclusions from rate recovery of approximately $1.7 billion of costs related to the V.C. Summer Units 2 and 3 new nuclear development project and approximately $180 million to purchase the Columbia Energy Center power station. Subject to receipt of SCANA shareholder and any required regulatory approvals and meeting closing conditions, Dominion Energy targets closing by the end of 2018. See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF DOMINION ENERGY QUESTAR

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination for total consideration of $4.4 billion and Dominion Energy Questar became a wholly-owned subsidiary of Dominion Energy. In December 2016, Dominion Energy contributed Dominion Energy Questar Pipeline to Dominion Energy Midstream. See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF WHOLLY-OWNED MERCHANT SOLAR PROJECTS

Throughout 2017, Dominion Energy completed the acquisition of various wholly-owned merchant solar projects in California, North Carolina and Virginia for $356 million. The projects cost $541 million to construct, including the initial acquisition cost, and generate 259 MW.

Throughout 2016, Dominion Energy completed the acquisition of various wholly-owned merchant solar projects in North Carolina, South Carolina and Virginia for $32 million. The projects cost $421 million to construct, including the initial acquisition cost, and generate 221 MW.

Throughout 2015, Dominion Energy completed the acquisition of various wholly-owned merchant solar projects in California and Virginia for $381 million. The projects cost $588 million to construct, including the initial acquisition cost, and generate 182 MW.

Throughout 2014, Dominion Energy completed the acquisition of various wholly-owned solar development projects in California for $200 million. The projects cost $578 million to construct, including the initial acquisition cost, and generate 179 MW.

See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF VIRGINIA POWER SOLAR PROJECTS

In 2017, Virginia Power entered into agreements to acquire two solar development projects in North Carolina. The projects are expected to close in 2018 and 2019 with a total expected cost of $280 million once constructed, including the initial acquisition cost, and will generate approximately 155 MW combined. See Note 10 to the Consolidated Financial Statements for additional information.

SALE OF CERTAIN RETAIL ENERGY MARKETING ASSETS

In October 2017, Dominion Energy entered into an agreement to sell certain assets associated with its nonregulated retail energy marketing operations for total consideration of $143 million, subject to customary approvals and certain adjustments. Pursuant to the agreement, upon the first closing in December 2017,

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Dominion Energy entered into a commission agreement under which the buyer will pay a commission in connection with the right to use Dominion Energy's brand in marketing materials and other services over a ten-year term. See Note 10 to the Consolidated Financial Statements for additional information.

ASSIGNMENT OF TOWER RENTAL PORTFOLIO

Virginia Power rents space on certain of its electric transmission towers to various wireless carriers for communications antennas and other equipment. In March 2017, Virginia Power sold its rental portfolio to Vertical Bridge Towers II, LLC for $91 million in cash. See Note 10 to the Consolidated Financial Statements for additional information.

ACQUISITION OF NON-WHOLLY-OWNED MERCHANT SOLAR PROJECTS

In 2015, Dominion Energy acquired 50% of the units in Four Brothers and Three Cedars from SunEdison for $107 million. In November 2016, NRG acquired the 50% of units in Four Brothers and Three Cedars previously held by SunEdison. The facilities began commercial operations in the third quarter of 2016, with generating capacity of 530 MW, at a cost of $1.1 billion. See Note 3 to the Consolidated Financial Statements for additional information.

SALE OF INTEREST IN MERCHANT SOLAR PROJECTS

In September 2015, Dominion Energy signed an agreement to sell a noncontrolling interest (consisting of 33% of the equity interests) in all of its then wholly-owned merchant solar projects, 24 solar projects totaling 425 MW, to SunEdison. In December 2015, the sale of interest in 15 of the solar projects closed for $184 million with the sale of interest in the remaining projects completed in January 2016 for $117 million. Upon closing, SunEdison sold its interest in these projects to Terra Nova Renewable Partners. See Note 3 to the Consolidated Financial Statements for additional information.

DOMINION ENERGY MIDSTREAM ACQUISITION OF INTEREST IN IROQUOIS

In September 2015, Dominion Energy Midstream acquired from NG and NJNR a 25.93% noncontrolling partnership interest in Iroquois. The investment was recorded at $216 million based on the value of Dominion Energy Midstream's common units at closing. The common units issued to NG and NJNR are reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements. See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF DECG

In January 2015, Dominion Energy completed the acquisition of 100% of the equity interests of DECG from SCANA for $497 million in cash, as adjusted for working capital. In April 2015, Dominion Energy contributed DECG to Dominion Energy Midstream. See Note 3 to the Consolidated Financial Statements for additional information.

ASSIGNMENTS OF SHALE DEVELOPMENT RIGHTS

In December 2013, Dominion Energy Gas closed on agreements with two natural gas producers to convey over time approximately 100,000 acres of Marcellus Shale development rights underneath several natural gas storage fields. The agreements provided for payments to Dominion Energy Gas, subject to customary adjustments, of approximately $200 million over a period of nine years, and an overriding royalty interest in gas produced from that acreage. In March 2015, Dominion Energy Gas and a natural gas producer closed on an amendment to a December 2013 agreement, which included the immediate conveyance of approximately 9,000 acres of Marcellus Shale development rights and a two-year extension of the term of the original agreement. The conveyance of development rights resulted in the recognition of $43 million of previously deferred revenue. In April 2016, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the immediate conveyance of a 32% partial interest in the remaining approximately 70,000 acres. This conveyance resulted in the recognition of the remaining $35 million of previously deferred revenue. In August 2017, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the finalization of contractual matters on previous conveyances, the conveyance of Dominion Energy Gas' remaining 68% interest in approximately 70,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage. As a result of this amendment, Dominion Energy Gas will receive total consideration of $130 million, with $65 million received in November 2017 and $65 million to be received by the end of the third quarter of 2018 in connection with the final conveyance.

In March 2015, Dominion Energy Gas conveyed to a natural gas producer approximately 11,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields and received proceeds of $27 million and an overriding royalty interest in gas produced from the acreage.

In September 2015, Dominion Energy Gas closed on an agreement with a natural gas producer to convey approximately 16,000 acres of Utica and Point Pleasant Shale development rights underneath one of its natural gas storage fields. The agreement provided for a payment to Dominion Energy Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage.

In November 2014, Dominion Energy Gas closed on an agreement with a natural gas producer to convey over time approximately 24,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields. The agreement provided for payments to Dominion Energy Gas, subject to customary adjustments, of approximately $120 million over a period of four years, and an overriding royalty interest in gas produced from the acreage. In January 2018, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the conveyance of Dominion Energy Gas' remaining 50% interest in approximately 18,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage for proceeds of $28 million.

See Note 10 to the Consolidated Financial Statements for additional information on these sales of Marcellus acreage.

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SALE OF ELECTRIC RETAIL ENERGY MARKETING BUSINESS

In March 2014, Dominion Energy completed the sale of its electric retail energy marketing business. The proceeds were $187 million, net of transaction costs. The sale of the electric retail energy marketing business did not qualify for discontinued operations classification.

SALE OF PIPELINES AND PIPELINE SYSTEMS

In March 2014, Dominion Energy Gas sold the Northern System to an affiliate that subsequently sold the Northern System to Blue Racer for consideration of $84 million. Dominion Energy Gas' consideration consisted of $17 million in cash proceeds and the extinguishment of affiliated current borrowings of $67 million and Dominion Energy's consideration consisted of cash proceeds of $84 million.

In September 2013, DETI sold Line TL-388 to Blue Racer for $75 million in cash proceeds.

SALE OF BRAYTON POINT, KINCAID AND EQUITY METHOD INVESTMENT IN ELWOOD

In August 2013, Dominion Energy completed the sale of Brayton Point, Kincaid and its equity method investment in Elwood to Energy Capital Partners and received proceeds of $465 million, net of transaction costs. The historical results of Brayton Point's and Kincaid's operations are presented in discontinued operations.

OPERATING SEGMENTS

Dominion Energy manages its daily operations through three primary operating segments: Power Delivery, Power Generation and Gas Infrastructure. Dominion Energy also reports a Corporate and Other segment, which includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's other operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Virginia Power manages its daily operations through two primary operating segments: Power Delivery and Power Generation. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Dominion Energy Gas manages its daily operations through its primary operating segment: Gas Infrastructure. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Energy Gas as a result of Dominion Energy's basis in the net assets contributed.

While daily operations are managed through the operating segments previously discussed, assets remain wholly-owned by the Companies and their respective legal subsidiaries.

A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion Energy	Virginia Power	Dominion Energy Gas
Power Delivery	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Power Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Gas Infrastructure	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG terminalling and storage	X		
	Nonregulated retail energy marketing	X		

(1) Includes remaining producer services activities.

For additional financial information on operating segments, including revenues from external customers, see Note 25 to the Consolidated Financial Statements. For additional information on operating revenue related to the Companies' principal products and services, see Notes 2 and 4 to the Consolidated Financial Statements, which information is incorporated herein by reference.

Power Delivery

The Power Delivery Operating Segment of Dominion Energy and Virginia Power includes Virginia Power's regulated electric transmission and distribution (including customer service) operations, which serve approximately 2.6 million residential, commercial, industrial and governmental customers in Virginia and North Carolina.

Power Delivery's existing five-year investment plan includes spending approximately $8.5 billion from 2018 through 2022 to upgrade or add new transmission and distribution lines, substations and other facilities to meet growing electricity demand within its service territory and maintain reliability and regulatory compliance. The proposed electric delivery infrastructure projects are intended to address both continued customer growth and increases in electricity consumption. In addition, data centers continue to contribute to anticipated demand growth.

Revenue provided by electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Variability in earnings is driven primarily by changes in rates, weather, customer growth and other factors impacting consumption such as the economy and energy conservation, in addition to operating and maintenance expenditures. Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link investments to operational results. SAIDI performance results, excluding major events, were 117 minutes at the end of 2017, down from the three-year average of 123 minutes. Virginia Power's overall customer satisfaction improved year over year when compared to 2016 J.D.

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Power and Associates' scoring. In the future, safety, electric service reliability, outage durations and customer service will remain key focus areas for electric distribution. Modernizing the electric grid will become a key focus area to support the enhancement of the customer service experience, build upon improvements in resiliency and security and support enhanced innovation and renewable generation.

Revenue provided by Virginia Power's electric transmission operations is based primarily on rates approved by FERC. The profitability of this business is dependent on its ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability in earnings primarily results from changes in rates and the timing of property additions, retirements and depreciation.

Virginia Power is a member of PJM, a RTO, and its electric transmission facilities are integrated into PJM wholesale electricity markets. Consistent with the increased authority given to NERC by EPACT, Virginia Power's electric transmission operations are committed to meeting NERC standards, modernizing its infrastructure and maintaining superior system reliability. Virginia Power's electric transmission operations will continue to focus on safety, operational performance, NERC compliance and execution of PJM's RTEP.

COMPETITION

Power Delivery Operating Segment— Dominion Energy and Virginia Power

There is no competition for electric distribution service within Virginia Power's service territory in Virginia and North Carolina and no such competition is currently permitted. Historically, since its electric transmission facilities are integrated into PJM and electric transmission services are administered by PJM, there was no competition in relation to transmission service provided to customers within the PJM region. However, competition from non-incumbent PJM transmission owners for development, construction and ownership of certain transmission facilities in Virginia Power's service territory is now permitted pursuant to Order 1000, subject to state and local siting and permitting approvals. This could result in additional competition to build and own transmission infrastructure in Virginia Power's service area in the future and could allow Dominion Energy to seek opportunities to build and own facilities in other service territories.

REGULATION

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Virginia Power's electric distribution service, including the rates it may charge to jurisdictional customers, is subject to regulation by the Virginia and North Carolina Commissions. Virginia Power's wholesale electric transmission rates, tariffs and terms of service are subject to regulation by FERC. Electric transmission siting authority remains the jurisdiction of the Virginia and North Carolina Commissions. However, EPACT provides FERC with certain backstop authority for transmission siting. See *State Regulations and Federal Regulations* in *Regulation* and Note 13 to the Consolidated Financial Statements for additional information.

PROPERTIES

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Virginia Power has approximately 6,600 miles of electric transmission lines of 69 kV or more located in North Carolina, Virginia and West Virginia. Portions of Virginia Power's electric transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, any surplus capacity that may exist in these lines. While Virginia Power owns and maintains its electric transmission facilities, they are a part of PJM, which coordinates the planning, operation, emergency assistance and exchange of capacity and energy for such facilities.

As a part of PJM's RTEP process, PJM authorized the following material reliability projects (including Virginia Power's estimated cost):

- Surry-to-Skiffes Creek-to-Whealton ($325 million);
- Mt. Storm-to-Dooms ($240 million);
- Idylwood substation ($110 million);
- Dooms-to-Lexington ($130 million);
- Cunningham-to-Elmont ($110 million);
- Landstown voltage regulation ($70 million);
- Warrenton (including Remington CT-to-Warrenton, Vint Hill-to-Wheeler-to-Gainesville, and Vint Hill and Wheeler switching stations) ($110 million);
- Remington/Gordonsville/Pratts Area Improvement (including Remington-to-Gordonsville, and new Gordonsville substation transformer) ($110 million);
- Gainesville-to-Haymarket ($55 million);
- Kings Dominion-to-Fredericksburg ($50 million);
- Loudoun-Brambleton line-to-Poland Road Substation ($60 million);
- Cunningham-to-Dooms ($60 million);
- Carson-to-Rogers Road ($55 million);
- Dooms-Valley rebuild ($65 million);
- Mt. Storm-Valley rebuild ($225 million);
- Glebe-to-Station ($320 million);
- Idylwood-to-Tysons ($125 million);
- Chesterfield-to-Lakeside ($35 million); and
- Landstown-to-Thrasher ($25 million).

In addition, in December 2017, the Virginia Commission granted Virginia Power a CPCN to rebuild and operate in Lancaster County, Virginia and Middlesex County, Virginia, approximately 2 miles of existing 115 kV transmission lines to be constructed under the Rappahannock River between Harmony Village Substation and White Stone Substation. The total estimated cost of the project is approximately $85 million.

Virginia Power plans to increase transmission substation physical security and expects to invest $250 million—$300 million through 2022 to strengthen its electrical system to better protect critical equipment, enhance its spare equipment process and create multiple levels of security.

In addition, Virginia Power's electric distribution network includes approximately 57,900 miles of distribution lines, exclusive of service level lines, in Virginia and North Carolina. The grants for most of its electric lines contain rights-of-way that have been obtained from the apparent owners of real estate, but underlying titles have not been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many electric lines are on publicly-owned property, where permission to operate can be revoked.

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Virginia legislation in 2014 provides for the recovery of costs, subject to approval by the Virginia Commission, for Virginia Power to move approximately 4,000 miles of electric distribution lines underground. The program is designed to reduce restoration outage time by moving Virginia Power's most outage-prone overhead distribution lines underground, has an annual investment cap of approximately $175 million and is expected to be completed over the next decade. In August 2016, the Virginia Commission approved the first phase of the program encompassing approximately 400 miles of converted lines and $140 million in capital spending (with approximately $123 million recoverable through Rider U). In September 2017, the Virginia Commission approved recovery through Rider U of a total capital investment of $40 million for second phase conversions.

SOURCES OF ENERGY SUPPLY

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Power Delivery's supply of electricity to serve Virginia Power customers is produced or procured by Power Generation. See *Power Generation* for additional information.

SEASONALITY

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Power Delivery's earnings vary seasonally as a result of the impact of changes in temperature, the impact of storms and other catastrophic weather events, and the availability of alternative sources for heating on demand by residential and commercial customers. Generally, the demand for electricity peaks during the summer and winter months to meet cooling and heating needs. An increase in heating degree days for Power Delivery's electric utility-related operations does not produce the same increase in revenue as an increase in cooling degree days, due to seasonal pricing differentials and because alternative heating sources are more readily available.

Power Generation

The Power Generation Operating Segment of Virginia Power includes the generation operations of the Virginia Power regulated electric utility and its related energy supply operations. Virginia Power's utility generation operations primarily serve the supply requirements for Power Delivery's utility customers. *The Power Generation Operating Segment of Dominion Energy* includes Virginia Power's generation facilities and its related energy supply operations as well as the generation operations of Dominion Energy's merchant fleet and energy marketing and price risk management activities for these assets.

Power Generation's existing five-year investment plan includes spending approximately $8.3 billion from 2018 through 2022 to construct new generation capacity and extend the life of nuclear generation facilities to meet growing electricity demand within its service territory and maintain reliability. The most significant project currently under construction is Greensville County, which is estimated to cost approximately $1.3 billion, excluding financing costs. See *Properties* and *Environmental Strategy* for additional information on this and other utility projects.

In addition, Dominion Energy's merchant fleet includes numerous renewable generation facilities, which include a fuel cell generation facility in Connecticut and solar generation facilities in operation or development in nine states, including Virginia. The output of these facilities is primarily sold under long-term power purchase agreements with terms generally ranging from 15 to 25 years. See Notes 3 and 10 to the Consolidated Financial Statements for additional information regarding certain solar projects.

Earnings for the *Power Generation Operating Segment of Virginia Power* primarily result from the sale of electricity generated by its utility fleet. Revenue is based primarily on rates established by state regulatory authorities and state law. Approximately 82% of revenue comes from serving Virginia jurisdictional customers. Base rates for the Virginia jurisdiction are set using a modified cost-of-service rate model, and are generally designed to allow an opportunity to recover the cost of providing utility service and earn a reasonable return on investments used to provide that service. Earnings variability may arise when revenues are impacted by factors not reflected in current rates, such as the impact of weather on customers' demand for services. Likewise, earnings may reflect variations in the timing or nature of expenses as compared to those contemplated in current rates, such as labor and benefit costs, capacity expenses, and the timing, duration and costs of scheduled and unscheduled outages. The cost of fuel and purchased power is generally collected through fuel cost-recovery mechanisms established by regulators and does not materially impact net income. The cost of new generation facilities is generally recovered through rate adjustment clauses in Virginia. Variability in earnings from rate adjustment clauses reflects changes in the authorized ROE and the carrying amount of these facilities, which are largely driven by the timing and amount of capital investments, as well as depreciation. See Note 13 to the Consolidated Financial Statements for additional information.

The Power Generation Operating Segment of Dominion Energy derives its earnings primarily from the sale of electricity generated by Virginia Power's utility and Dominion Energy's merchant generation assets, as well as from associated capacity and ancillary services. Variability in earnings provided by Dominion Energy's nonrenewable merchant fleet relates to changes in market-based prices received for electricity and capacity. Market-based prices for electricity are largely dependent on commodity prices, primarily natural gas, and the demand for electricity, which is primarily dependent upon weather. Capacity prices are dependent upon resource requirements in relation to the supply available (both existing and new) in the forward capacity auctions, which are held approximately three years in advance of the associated delivery year. Dominion Energy manages the electric price volatility of its merchant fleet by hedging a substantial portion of its expected near-term energy sales with derivative instruments. Variability also results from changes in the cost of fuel consumed, labor and benefits and the timing, duration and costs of scheduled and unscheduled outages. Variability in earnings provided by Dominion Energy's renewable merchant fleet is primarily driven by weather.

COMPETITION

Power Generation Operating Segment—Dominion Energy and Virginia Power

Virginia Power's generation operations are not subject to significant competition as only a limited number of its Virginia jurisdictional electric utility customers have retail choice. See *Electric* under *State Regulations* in *Regulation* for more information. Currently, North Carolina does not offer retail choice to electric customers.

Power Generation Operating Segment—Dominion Energy

Power Generation's recently acquired and developed renewable generation projects are not currently subject to significant competition as the output from these facilities is primarily sold under long-term power purchase agreements with terms generally ranging from 15 to 25 years. Competition for the nonrenewable merchant fleet is impacted by electricity and fuel prices, new market entrants, construction by others of generating assets and transmission capacity, technological advances in power generation, the actions of environmental and other regulatory authorities and other factors. These competitive factors may negatively impact the merchant fleet's ability to profit from the sale of electricity and related products and services.

Unlike Power Generation's regulated generation fleet, its nonrenewable merchant generation fleet is dependent on its ability to operate in a competitive environment and does not have a predetermined rate structure that provides for a rate of return on its capital investments. Power Generation's nonrenewable merchant assets operate within functioning RTOs and primarily compete on the basis of price. Competitors include other generating assets bidding to operate within the RTOs. Power Generation's nonrenewable merchant units compete in the wholesale market with other generators to sell a variety of products including energy, capacity and ancillary services. It is difficult to compare various types of generation given the wide range of fuels, fuel procurement strategies, efficiencies and operating characteristics of the fleet within any given RTO. However, Dominion Energy applies its expertise in operations, dispatch and risk management to maximize the degree to which its nonrenewable merchant fleet is competitive compared to similar assets within the region.

In November 2017, Connecticut adopted the Act Concerning Zero Carbon Solicitation and Procurement, which allows nuclear generating facilities to compete for power purchase agreements in a state sponsored procurement for electricity. In February 2018, Connecticut regulators recommended pursuing the procurement. They are expected to issue a request for proposals by May 1, 2018. Millstone will participate in the state sponsored procurement. If successful in the competitive bid process, Millstone would receive a long-term power purchase agreement for between three and ten years.

REGULATION

Power Generation Operating Segment—Dominion Energy and Virginia Power

Virginia Power's utility generation fleet and Dominion Energy's merchant generation fleet are subject to regulation by FERC, the NRC, the EPA, the DOE, the Army Corps of Engineers and other federal, state and local authorities. Virginia Power's utility generation fleet is also subject to regulation by the Virginia and North Carolina Commissions. See *Regulation, Future Issues and Other Matters* in Item 7. MD&A and Notes 13 and 22 to the Consolidated Financial Statements for more information.

PROPERTIES

For a listing of Dominion Energy's and Virginia Power's existing generation facilities, see Item 2. Properties.

Power Generation Operating Segment—Dominion Energy and Virginia Power

The generation capacity of Virginia Power's electric utility fleet totals approximately 20,800 MW. The generation mix is diversified and includes gas, coal, nuclear, oil, renewables, biomass and power purchase agreements. Virginia Power's generation facilities are located in Virginia, West Virginia and North Carolina and serve load in Virginia and northeastern North Carolina.

Virginia Power is developing, financing and constructing new generation capacity to meet growing electricity demand within its service territory. Significant projects under construction or development are set forth below:

- Virginia Power plans to acquire or construct certain solar facilities in Virginia and North Carolina. See Notes 10 and 13 to the Consolidated Financial Statements for more information.
- Virginia Power continues to consider the construction of a third nuclear unit at a site located at North Anna. See Note 13 to the Consolidated Financial Statements for more information on this project.
- Virginia Power is considering the construction of a hydroelectric pumped storage facility in Southwest Virginia.
- In March 2016, the Virginia Commission authorized the construction of Greensville County and related transmission interconnection facilities. Commercial operations are expected to commence in late 2018, at an estimated cost of approximately $1.3 billion, excluding financing costs.
- In June 2017, Virginia Power signed an agreement to develop two 6 MW wind turbines off the coast of Virginia for the Coastal Virginia Offshore Wind project. The project is expected to cost approximately $300 million and to be installed by the end of 2020.
- In October 2017, Virginia Power received a permit by rule from the VDEQ to construct and operate the Hollyfield solar facility, a 17 MW solar facility in King William County, Virginia and related distribution interconnection facilities. The total estimated cost of the Hollyfield solar facility is approximately $33 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the University of Virginia, an agency of the Commonwealth of Virginia and a non-jurisdictional customer, will compensate Virginia Power for the facility's net electrical energy output.

Power Generation Operating Segment—Dominion Energy

The generation capacity of Dominion Energy's merchant fleet totals approximately 5,100 MW. The generation mix is diversified and includes nuclear, natural gas and renewables. Merchant nonrenewable generation facilities are located in Connecticut, Pennsylvania and Rhode Island, with a majority of that capacity concentrated in New England. Dominion Energy's merchant renewable generation facilities include a fuel cell generation facility in Connecticut, solar generation facilities in California, Connecticut, Georgia, Indiana, North Carolina, South Carolina, Tennessee, Utah and Virginia, and wind generation facilities in Indiana and West Virginia.

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Sources of Energy Supply

Power Generation Operating Segment—Dominion Energy and Virginia Power

Power Generation uses a variety of fuels to power its electric generation and purchases power for utility system load requirements and to satisfy physical forward sale requirements, as described below. Some of these agreements have fixed commitments and are included as contractual obligations in *Future Cash Payments for Contractual Obligations and Planned Capital Expenditures* in Item 7. MD&A.

Nuclear Fuel—Power Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent on the market environment. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs. Additional fuel is purchased as required to ensure optimal cost and inventory levels.

Fossil Fuel—Power Generation primarily utilizes natural gas and coal in its fossil fuel plants. All recent fossil fuel plant construction for Power Generation involves natural gas generation.

Power Generation's natural gas and oil supply is obtained from various sources including purchases from major and independent producers in the Mid-Continent and Gulf Coast regions, purchases from local producers in the Appalachian area and Marcellus and Utica regions, purchases from gas marketers and withdrawals from underground storage fields owned by Dominion Energy or third parties. Power Generation manages a portfolio of natural gas transportation contracts (capacity) that provides for reliable natural gas deliveries to its gas turbine fleet, while minimizing costs.

Power Generation's coal supply is obtained through long-term contracts and short-term spot agreements from domestic suppliers.

Biomass—Power Generation's biomass supply is obtained through long-term contracts and short-term spot agreements from local suppliers.

Purchased Power—Power Generation purchases electricity from the PJM spot market and through power purchase agreements with other suppliers to provide for utility system load requirements.

Power Generation also occasionally purchases electricity from the PJM and ISO-NE spot markets to satisfy physical forward sale requirements as part of its merchant generation operations.

Power Generation Operating Segment—Virginia Power

Presented below is a summary of Virginia Power's actual system output by energy source:

Source	2017	2016	2015
Nuclear(1)	**32%**	31%	30%
Natural gas	**32**	31	23
Coal(2)	**17**	24	26
Purchased power, net	**14**	8	15
Other(3)	**5**	6	6
Total	**100%**	100%	100%

(1) Excludes ODEC's 11.6% ownership interest in North Anna.
(2) Excludes ODEC's 50.0% ownership interest in the Clover power station.
(3) Includes oil, hydro, biomass and solar.

Seasonality

Power Generation Operating Segment—Dominion Energy and Virginia Power

Sales of electricity for Power Generation typically vary seasonally as a result of the impact of changes in temperature and the availability of alternative sources for heating on demand by residential and commercial customers. See *Power Delivery-Seasonality* above for additional considerations that also apply to Power Generation.

Nuclear Decommissioning

Power Generation Operating Segment—Dominion Energy and Virginia Power

Virginia Power has a total of four licensed, operating nuclear reactors at Surry and North Anna in Virginia.

Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. Amounts collected from ratepayers are placed into trusts and are invested to fund the expected future costs of decommissioning the Surry and North Anna units.

Virginia Power believes that the decommissioning funds and their expected earnings for the Surry and North Anna units will be sufficient to cover expected decommissioning costs, particularly when combined with future ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. This reflects the long-term investment horizon, since the units will not be decommissioned for decades, and a positive long-term outlook for trust fund investment returns. Virginia Power will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirements, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC.

The estimated cost to decommission Virginia Power's four nuclear units is reflected in the table below and is primarily based upon site-specific studies completed in 2014. These cost studies are generally completed every four to five years. The current cost estimates assume decommissioning activities will begin shortly after cessation of operations, which will occur when the operating licenses expire.

Under the current operating licenses, Virginia Power is scheduled to decommission the Surry and North Anna units during the period 2032 to 2078. NRC regulations allow licensees to apply for extension of an operating license in up to 20-year increments. Virginia Power has announced its intention to apply for operating life extensions for Surry and North Anna.

Power Generation Operating Segment—Dominion Energy

In addition to the four nuclear units discussed above, Dominion Energy has two licensed, operating nuclear reactors at Millstone in Connecticut. A third Millstone unit ceased operations before Dominion Energy acquired the power station. In May 2013, Dominion Energy ceased operations at its single Kewaunee unit in Wisconsin and commenced decommissioning activities using the SAFSTOR methodology. The planned decommissioning completion date is 2073, which is within the NRC allowed 60-year window.

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As part of Dominion Energy's acquisition of both Millstone and Kewaunee, it acquired decommissioning funds for the related units. Any funds remaining in Kewaunee's trust after decommissioning is completed are required to be refunded to Wisconsin ratepayers. Dominion Energy believes that the amounts currently available in the decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. Dominion Energy will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirements, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC. The estimated cost to decommission Dominion Energy's eight units is reflected in the table below and is primarily based upon site-specific studies completed for Surry, North Anna and Millstone in 2014 and for Kewaunee in 2013.

The estimated decommissioning costs and license expiration dates for the nuclear units owned by Dominion Energy and Virginia Power are shown in the following table:

	NRC license expiration year	Most recent cost estimate (2017 dollars)(1)	Funds in trusts at December 31, 2017	2017 contributions to trusts
(dollars in millions)				
Surry				
Unit 1	2032	$ 612	$ 680	$ —
Unit 2	2033	633	670	—
North Anna				
Unit 1(2)	2038	524	541	—
Unit 2(2)	2040	536	508	—
Total (Virginia Power)		2,305	2,399	—
Millstone				
Unit 1(3)	N/A	377	533	—
Unit 2	2035	575	700	—
Unit 3(4)	2045	698	688	—
Kewaunee				
Unit 1(5)	N/A	452	773	—
Total (Dominion Energy)		$ 4,407	$ 5,093	$ —

(1) The cost estimates shown above reflect reductions for the expected future recovery of certain spent fuel costs based on Dominion Energy's and Virginia Power's contracts with the DOE for disposal of spent nuclear fuel consistent with the reductions reflected in Dominion Energy's and Virginia Power's nuclear decommissioning AROs.

(2) North Anna is jointly owned by Virginia Power (88.4%) and ODEC (11.6%). However, Virginia Power is responsible for 89.26% of the decommissioning obligation. Amounts reflect 89.26% of the decommissioning cost for both of North Anna's units.

(3) Unit 1 permanently ceased operations in 1998, before Dominion Energy's acquisition of Millstone.

(4) Millstone Unit 3 is jointly owned by Dominion Energy Nuclear Connecticut, Inc., with a 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal and Green Mountain. Decommissioning cost is shown at Dominion Energy's ownership percentage. At December 31, 2017, the minority owners held $42 million of trust funds related to Millstone Unit 3 that are not reflected in the table above.

(5) Permanently ceased operations in 2013.

Also see Notes 14 and 22 to the Consolidated Financial Statements for further information about AROs and nuclear decommissioning, respectively, and Note 9 to the Consolidated Financial Statements for information about nuclear decommissioning trust investments.

Gas Infrastructure

The Gas Infrastructure Operating Segment of Dominion Energy Gas includes certain of Dominion Energy's regulated natural gas operations. DETI, the gas transmission pipeline and storage business, serves gas distribution businesses and other customers in the Northeast, mid-Atlantic and Midwest. East Ohio, the primary gas distribution business of Dominion Energy Gas, serves residential, commercial and industrial gas sales, transportation and gathering service customers primarily in Ohio. DGP conducts gas gathering and processing activities, which include the sale of extracted products at market rates, primarily in West Virginia, Ohio and Pennsylvania. Dominion Iroquois holds a 24.07% noncontrolling partnership interest in Iroquois, which provides service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, through interconnecting pipelines and exchanges primarily in New York.

The Gas Infrastructure Operating Segment of Dominion Energy includes LNG operations, Dominion Energy Questar operations, Hope's gas distribution operations in West Virginia, and nonregulated retail natural gas marketing, as well as Dominion Energy's investments in the Blue Racer joint venture, Atlantic Coast Pipeline and Dominion Energy Midstream. See *Properties and Investments* below for additional information regarding the Blue Racer and Atlantic Coast Pipeline investments. Dominion Energy's LNG operations involve the import and storage of LNG at Cove Point and the transportation of regasified LNG to the interstate pipeline grid and mid-Atlantic and Northeast markets. Dominion Energy has received DOE and FERC approval to export LNG from Cove Point and, once the Liquefaction Project commences commercial operations, will be able to import LNG and regasify it as natural gas and liquefy natural gas and export it as LNG. See Note 22 to the Consolidated Financial Statements for more information.

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination and Dominion Energy Questar, a Rockies-based integrated natural gas company, became a wholly-owned subsidiary of Dominion Energy. Dominion Energy Questar included Questar Gas, Wexpro and Dominion Energy Questar Pipeline at closing. Questar Gas' regulated gas distribution operations in Utah, southwestern Wyoming and southeastern Idaho includes 29,600 miles of gas distribution pipeline. Wexpro develops and produces natural gas from reserves supplied to Questar Gas under a cost-of-service framework. Dominion Energy Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage services in Utah, Wyoming and western Colorado through 2,200 miles of gas transmission pipeline and 56 bcf of working gas storage. See *Acquisitions and Dispositions* above and Note 3 to the Consolidated Financial Statements for a description of the Dominion Energy Questar Combination.

In 2014, Dominion Energy formed Dominion Energy Midstream, an MLP initially consisting of a preferred equity interest in Cove Point. See *General* above for more information. Also see *Acquisitions and Dispositions* above and Note 3 to the Consolidated Financial Statements for a description of Dominion Energy's contribution of Dominion Energy Questar Pipeline to

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Dominion Energy Midstream in December 2016 as well as Dominion Energy's acquisition of DECG, which Dominion Energy contributed to Dominion Energy Midstream in April 2015, and Dominion Energy Midstream's acquisition of a 25.93% noncontrolling partnership interest in Iroquois in September 2015. DECG provides FERC-regulated interstate natural gas transportation services in South Carolina and southeastern Georgia through 1,500 miles of gas transmission pipeline.

Gas Infrastructure's existing five-year investment plan includes spending approximately $8.3 billion from 2018 through 2022 to upgrade existing or add new infrastructure to meet growing energy needs within its service territory and maintain reliability. Demand for natural gas is expected to continue to grow as initiatives to transition to gas from more carbon-intensive fuels are implemented. This plan includes Dominion Energy's portion of spending for the Atlantic Coast Pipeline Project.

Earnings for the *Gas Infrastructure Operating Segment of Dominion Energy Gas* primarily result from rates established by FERC and the Ohio Commission. The profitability of this business is dependent on Dominion Energy Gas' ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability in earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

Approximately 91% of DETI's transmission capacity is subscribed including 86% under long-term contracts (two years or greater) and 5% on a year-to-year basis. DETI's storage services are 100% subscribed with long-term contracts.

Revenue from processing and fractionation operations largely results from the sale of commodities at market prices. For DGP's processing plants, Dominion Energy Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion Energy Gas to commodity price risk for the value of the spread between the NGL products and natural gas. In addition, Dominion Energy Gas has volumetric risk as the majority of customers receiving these services are not required to deliver minimum quantities of gas.

East Ohio utilizes a straight-fixed-variable rate design for a majority of its customers. Under this rate design, East Ohio recovers a large portion of its fixed operating costs through a flat monthly charge accompanied by a reduced volumetric base delivery rate. Accordingly, East Ohio's revenue is less impacted by weather-related fluctuations in natural gas consumption than under the traditional rate design.

Earnings for the *Gas Infrastructure Operating Segment of Dominion Energy* primarily include the results of rates established by FERC and the West Virginia, Utah, Wyoming and Idaho Commissions. Additionally, Dominion Energy receives revenue from firm fee-based contractual arrangements, including negotiated rates, for certain LNG storage and terminalling services. Dominion Energy Questar Pipeline's and DECG's revenues are primarily derived from reservation charges for firm transportation and storage services as provided for in their FERC-approved tariffs. Revenue provided by Questar Gas' operations is based primarily on rates established by the Utah and Wyoming Commissions. The Idaho Commission has contracted with the Utah Commission for rate oversight of Questar Gas operations in a small area of southeastern Idaho. Hope's gas distribution operations in West Virginia serve residential, commercial, sale for resale and industrial gas sales, transportation and gathering service customers. Revenue provided by Hope's operations is based primarily on rates established by the West Virginia Commission. The profitability of these businesses is dependent on their ability, through the rates they are permitted to charge, to recover costs and earn a reasonable return on their capital investments. Variability in earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

COMPETITION

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy Gas' natural gas transmission operations compete with domestic and Canadian pipeline companies. Dominion Energy Gas also competes with gas marketers seeking to provide or arrange transportation, storage and other services. Alternative fuel sources, such as oil or coal, provide another level of competition. Although competition is based primarily on price, the array of services that can be provided to customers is also an important factor. The combination of capacity rights held on certain long-line pipelines, a large storage capability and the availability of numerous receipt and delivery points along its own pipeline system enable Dominion Energy to tailor its services to meet the needs of individual customers.

DGP's processing and fractionation operations face competition in obtaining natural gas supplies for its processing and related services. Numerous factors impact any given customer's choice of processing services provider, including the location of the facilities, efficiency and reliability of operations, and the pricing arrangements offered.

In Ohio, there has been no legislation enacted to require supplier choice for natural gas distribution consumers. However, East Ohio has offered an Energy Choice program to residential and commercial customers since October 2000. East Ohio has since taken various steps approved by the Ohio Commission toward exiting the merchant function, including restructuring its commodity service and placing Energy Choice-eligible customers in a direct retail relationship with participating suppliers. Further, in April 2013, East Ohio fully exited the merchant function for its nonresidential customers, which are now required to choose a retail supplier or be assigned to one at a monthly variable rate set by the supplier. At December 31, 2017, approximately 1 million of East Ohio's 1.2 million Ohio customers were participating in the Energy Choice program.

Gas Infrastructure Operating Segment—Dominion Energy

Questar Gas and Hope do not currently face direct competition from other distributors of natural gas for residential and commercial customers in their service territories as state regulations in Utah, Wyoming and Idaho for Questar Gas, and West Virginia for Hope, do not allow customers to choose their provider at this time. See *State Regulations* in *Regulation* for additional information.

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Cove Point's gas transportation, LNG import and storage operations, as well as the Liquefaction Project's capacity are contracted primarily under long-term fixed reservation fee agreements. However, in the future Cove Point may compete with other independent terminal operators as well as major oil and gas companies on the basis of terminal location, services provided and price. Competition from terminal operators primarily comes from refiners and distribution companies with marketing and trading arms.

Dominion Energy Questar Pipeline's and DECG's pipeline systems generate a substantial portion of their revenue from long-term firm contracts for transportation services and are therefore insulated from competitive factors during the terms of the contracts. When these long-term contracts expire, Dominion Energy Questar Pipeline's pipeline system faces competitive pressures from similar facilities that serve the Rocky Mountain region and DECG's pipeline system faces competitive pressures from similar facilities that serve the South Carolina and southeastern Georgia area in terms of location, rates, terms of service, and flexibility and reliability of service.

Dominion Energy's retail energy marketing operations compete against incumbent utilities and other energy marketers in nonregulated energy markets for natural gas. In March 2014, Dominion Energy completed the sale of its electric retail energy marketing business. In October 2017, Dominion Energy entered into an agreement to sell certain assets associated with its nonregulated retail energy marketing operations. The sale is expected to be completed by the end of 2018. The remaining retail natural gas business consists of approximately 350,000 customer accounts in five states. The heaviest concentration of customers in these markets are located in states where utilities have the advantage of long-standing commitment to customer choice, primarily Ohio and Pennsylvania.

REGULATION

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy Gas' natural gas transmission and storage operations are regulated primarily by FERC. East Ohio's gas distribution operations, including the rates that it may charge to customers, are regulated by the Ohio Commission. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

Gas Infrastructure Operating Segment—Dominion Energy

Cove Point's, Dominion Energy Questar Pipeline's, and DECG's operations are regulated primarily by FERC. Questar Gas' distribution operations, including the rates it may charge customers, are regulated by the Utah, Wyoming and Idaho Commissions. Hope's gas distribution operations, including the rates that it may charge customers, are regulated by the West Virginia Commission. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

PROPERTIES AND INVESTMENTS

For a description of Dominion Energy's and Dominion Energy Gas' existing facilities see Item 2. Properties.

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy Gas has the following significant projects under construction or development to better serve customers or expand its service offerings within its service territory.

In January 2018, DETI filed an application to request FERC authorization to construct and operate certain facilities located in Ohio and Pennsylvania for the Sweden Valley project. The project is expected to cost approximately $50 million and provide 120,000 Dths per day of firm transportation service from Pennsylvania to Ohio for delivery to Tennessee Gas Pipeline Company, L.L.C. The project's capacity is fully subscribed pursuant to a precedent agreement with one customer and is expected to be placed into service in the fourth quarter of 2019.

In September 2014, DETI announced its intent to construct and operate the Supply Header project which is estimated to cost between $550 million and $600 million to construct, excluding financing costs, and provide 1,500,000 Dths per day of firm transportation service to various customers. In December 2014, DETI entered into a precedent agreement with Atlantic Coast Pipeline for the Supply Header project. In October 2017, DETI received FERC authorization to construct and operate the project facilities, with the facilities expected to be in service in late 2019.

In 2008, East Ohio began PIR, aimed at replacing approximately 4,100 miles of its pipeline system at a cost of $2.7 billion. In 2011, approval was obtained to include an additional 1,450 miles and to increase annual capital investment to meet the program goal. The program will replace approximately 25% of the pipeline system and is anticipated to take place over a total of 25 years. In March 2015, East Ohio filed an application with the Ohio Commission requesting approval to extend the PIR program for an additional five years and to increase the annual capital investment, with corresponding increases in the annual rate-increase caps. In September 2016, the Ohio Commission approved a stipulation filed jointly by East Ohio and the Staff of the Ohio Commission to settle East Ohio's pending application. As requested, the PIR program and associated cost recovery will continue for another five-year term, calendar years 2017 through 2021, and East Ohio will be permitted to increase its annual capital expenditures to $200 million by 2018 and 3% per year thereafter subject to the cost recovery rate increase caps proposed by East Ohio. Costs associated with calendar year 2016 investment will be recovered under the existing terms. In April 2017, the Ohio Commission approved East Ohio's application to adjust the PIR cost recovery rates for 2016 costs. The filing reflects gross plan investment for 2016 of $188 million, cumulative gross plant investment of $1.2 billion and a revenue requirement of $157 million.

Gas Infrastructure Operating Segment—Dominion Energy

Dominion Energy has the following significant projects under construction or development.

Cove Point—Dominion Energy expects the Liquefaction Project to commence commercial operations in March 2018, which will enable the Cove Point facility to liquefy domestically-produced natural gas and export it as LNG. The DOE previously authorized Dominion Energy to export LNG to countries with free trade agreements. In September 2013, the DOE authorized

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Dominion Energy to export LNG from Cove Point to non-free trade agreement countries.

In September 2014, Cove Point received the FERC order authorizing the Liquefaction Project with certain conditions. The conditions regarding the Liquefaction Project set forth in the FERC order largely incorporate the mitigation measures proposed in the environmental assessment. In October 2014, Cove Point commenced construction of the Liquefaction Project, with an in-service date anticipated in March 2018 at a total estimated cost of approximately $4.1 billion, excluding financing costs. The Cove Point facility is authorized to export at a rate of 770 million cubic feet of natural gas per day for a period of 20 years.

In April 2013, Dominion Energy announced it had fully subscribed the capacity of the project with 20-year terminal service agreements. ST Cove Point, LLC, a joint venture of Sumitomo Corporation, a Japanese corporation that is one of the world's leading trading companies, and Tokyo Gas Co., Ltd., a Japanese corporation that is the largest natural gas utility in Japan, and GAIL Global (USA) LNG LLC, a wholly-owned indirect U.S. subsidiary of GAIL (India) Ltd., have each contracted for half of the capacity. Following completion of the front-end engineering and design work, Dominion Energy also announced it had awarded its engineering, procurement and construction contract for new liquefaction facilities to IHI/Kiewit Cove Point, a joint venture between IHI E&C International Corporation and Kiewit Energy Company.

Cove Point has historically operated as an LNG import facility under various long-term import contracts. Since 2010, Dominion Energy has renegotiated certain existing LNG import contracts in a manner that will result in a significant reduction in pipeline and storage capacity utilization and associated anticipated revenues during the period from 2017 through 2028. Such amendments created the opportunity for Dominion Energy to explore the Liquefaction Project, which, will extend the economic life of Cove Point and contribute to Dominion Energy's overall growth plan. In total, these renegotiations reduced Cove Point's expected annual revenues from the import-related contracts by approximately $150 million from 2017 through 2028, partially offset by approximately $50 million of additional revenues in the years 2013 through 2017.

In June 2015, Cove Point executed binding agreements with two customers for the approximately $150 million Eastern Market Access Project. In January 2018, Cove Point received FERC authorization to construct and operate the project facilities, which are expected to be placed into service in early 2019.

DECG—In 2014, DECG executed binding precedent agreements with three customers for the Charleston project. The project is expected to cost approximately $125 million, and provide 80,000 Dths per day of firm transportation service from an existing interconnect with Transcontinental Gas Pipe, LLC in Spartanburg County, South Carolina to customers in Dillon, Marlboro, Sumter, Charleston, Lexington and Remington counties, South Carolina. In February 2017, DECG received FERC approval to construct and operate the project facilities, which are expected to be placed into service in March 2018.

Questar Gas—In 2010, Questar Gas began replacing aging high pressure infrastructure under a cost-tracking mechanism that allows it to place into rate base and earn a return on capital expenditures associated with a multi-year natural gas infrastructure-replacement program upon the completion of each project. At that time, the commission-allowed annual spending in the replacement program was approximately $55 million.

In its 2014 Utah general rate case, Questar Gas received approval to include intermediate high pressure infrastructure in the replacement program and increase the annual spending limit to approximately $65 million, adjusted annually using a gross domestic product inflation factor. At that time, 420 miles of high pressure pipe and 70 miles of intermediate high pressure pipe were identified to be replaced in the program over a 17-year period. Questar Gas has spent about $65 million each year through 2017 under this program. The program is evaluated in each Utah general rate case. The next Utah general rate case is anticipated to occur in 2019.

Gas Infrastructure Equity Method Investments—In September 2015, Dominion Energy, through Dominion Energy Midstream, acquired an additional 25.93% interest in Iroquois. Dominion Energy Gas holds a 24.07% interest with TransCanada holding a 50% interest. Iroquois owns and operates a 416-mile FERC regulated interstate natural gas pipeline providing service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end-users, through interconnecting pipelines and exchanges. Iroquois' pipeline extends from the U.S.-Canadian border at Waddington, New York through the state of Connecticut to South Commack, Long Island, New York and continuing on from Northport, Long Island, New York through the Long Island Sound to Hunts Point, Bronx, New York. See Note 9 to the Consolidated Financial Statements for further information about Dominion Energy's equity method investment in Iroquois.

In September 2014, Dominion Energy, along with Duke and Southern Company Gas, announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion Energy an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion Energy purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. The members hold the following membership interests: Dominion Energy, 48%; Duke, 47%; and Southern Company Gas, 5%. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina, with development and construction costs estimated between $6.0 billion and $6.5 billion, excluding financing costs. In October 2014, Atlantic Coast Pipeline requested approval from FERC to utilize the pre-filing process under which environmental review for the natural gas pipeline project will commence. Atlantic Coast Pipeline filed its FERC application in September 2015 and expects to be in service in late 2019. In October 2017, Atlantic Coast Pipeline received the FERC order authorizing the construction and operation of the project. The FERC order has been appealed to the U.S. Court of Appeals for the Fourth Circuit and the project remains subject to other pending federal and state approvals. See Note 9 to the Consolidated Financial Statements for further information about Dominion Energy's equity method investment in Atlantic Coast Pipeline.

In December 2012, Dominion Energy formed Blue Racer with Caiman to provide midstream services to natural gas producers operating in the Utica Shale region in Ohio and portions

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of Pennsylvania. Blue Racer is an equal partnership between Dominion Energy and Caiman, with Dominion Energy contributing midstream assets and Caiman contributing private equity capital. Midstream services offered by Blue Racer include gathering, processing, fractionation, and natural gas liquids transportation and marketing. Blue Racer is expected to develop additional new capacity designed to meet producer needs as the development of the Utica Shale formation increases. See Note 9 to the Consolidated Financial Statements for further information about Dominion Energy's equity method investment in Blue Racer.

Sources of Energy Supply

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy's and Dominion Energy Gas' natural gas supply is obtained from various sources including purchases from major and independent producers in the Mid-Continent and Gulf Coast regions, local producers in the Appalachian area, gas marketers and, for Questar Gas specifically, from Wexpro and other producers in the Rocky Mountain region. Wexpro's gas development and production operations serve the majority of Questar Gas' gas supply requirements in accordance with the Wexpro Agreement and the Wexpro II Agreement, comprehensive agreements with the states of Utah and Wyoming. Dominion Energy's and Dominion Energy Gas' large underground natural gas storage network and the location of their pipeline systems are a significant link between the country's major interstate gas pipelines and large markets in the Northeast, mid-Atlantic and Rocky Mountain regions. Dominion Energy's and Dominion Energy Gas' pipelines are part of an interconnected gas transmission system, which provides access to supplies nationwide for local distribution companies, marketers, power generators and industrial and commercial customers.

Dominion Energy's and Dominion Energy Gas' underground storage facilities play an important part in balancing gas supply with consumer demand and are essential to serving the Northeast, mid-Atlantic, Midwest and Rocky Mountain regions. In addition, storage capacity is an important element in the effective management of both gas supply and pipeline transmission capacity.

The supply of gas to serve Dominion Energy's retail energy marketing customers is procured through Dominion Energy's energy marketing group and market wholesalers.

Seasonality

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Gas Infrastructure's natural gas distribution business earnings vary seasonally, as a result of the impact of changes in temperature on demand by residential and commercial customers for gas to meet heating needs. Historically, the majority of these earnings have been generated during the heating season, which is generally from November to March; however, implementation of rate mechanisms in Ohio for East Ohio, and Utah, Wyoming and Idaho for Questar Gas, have reduced the earnings impact of weather-related fluctuations. Demand for services at Dominion Energy's gas transmission and storage business can also be weather sensitive. Earnings are also impacted by changes in commodity prices driven by seasonal weather changes, the effects of unusual weather events on operations and the economy.

The earnings of Dominion Energy's retail energy marketing operations also vary seasonally. Generally, the demand for gas peaks during the winter months to meet heating needs.

Corporate and Other

Corporate and Other Segment-Virginia Power and Dominion Energy Gas

Virginia Power's and Dominion Energy Gas' Corporate and Other segments primarily include certain specific items attributable to their operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Corporate and Other Segment-Dominion Energy

Dominion Energy's Corporate and Other segment includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Regulation

The Companies are subject to regulation by various federal, state and local authorities, including the state commissions of Virginia, North Carolina, Ohio, West Virginia, Utah, Wyoming and Idaho, SEC, FERC, EPA, DOE, NRC, Army Corps of Engineers, and the Department of Transportation.

State Regulations

Electric

Virginia Power's electric utility retail service is subject to regulation by the Virginia Commission and the North Carolina Commission.

Virginia Power holds CPCNs which authorize it to maintain and operate its electric facilities now in operation and to sell electricity to customers. However, Virginia Power may not construct generating facilities or large capacity transmission lines without the prior approval of various state and federal government agencies. In addition, the Virginia Commission and the North Carolina Commission regulate Virginia Power's transactions with affiliates and transfers of certain facilities. The Virginia Commission also regulates the issuance of certain securities.

Electric Regulation in Virginia

The Regulation Act instituted a cost-of-service rate model, ending Virginia's planned transition to retail competition for electric supply service to most classes of customers.

The Regulation Act authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, FERC-approved transmission costs, underground distribution lines, environmental compliance, conservation and energy efficiency programs and renewable energy programs, and also contains statutory provisions directing Virginia Power to file annual fuel cost recovery cases with the Virginia Commission. As amended, it provides for enhanced returns on capital expenditures on specific newly-proposed generation projects.

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In February 2015, the Virginia Governor signed legislation into law which will keep Virginia Power's base rates unchanged until at least December 1, 2022. In addition, no biennial reviews will be conducted by the Virginia Commission for the five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. The legislation states that Virginia Power's 2015 biennial review, filed in March 2015, would proceed for the sole purpose of reviewing and determining whether any refunds are due to customers based on earnings performance for generation and distribution services during the 2013 and 2014 test periods. In addition the legislation requires the Virginia Commission to conduct proceedings in 2017 and 2019 to determine the utility's ROE for use in connection with rate adjustment clauses and requires utilities to file integrated resource plans annually rather than biennially. In November 2017, the Virginia Commission approved an ROE of 9.2% for rate adjustment clauses.

In February 2017, the Governor of Virginia signed legislation into law that allows utilities to file a rate adjustment clause to recover costs of pumped hydroelectricity generation and storage facilities that are located in the coalfield region of Virginia. In March 2017, the Governor of Virginia signed legislation into law that allows utilities to file a rate adjustment clause to recover, beginning in 2020, reasonably appropriate costs for extending the operating licenses, or the operating lives, of nuclear power generation facilities.

In March 2017, the Governor of Virginia signed legislation into law stating that it is in the public interest for utilities to replace existing overhead tap lines having nine or more total unplanned outage events-per-mile with new underground facilities, and that utilities can seek cost recovery for such new underground facilities through a rate adjustment clause.

If the Virginia Commission's future rate decisions, including actions relating to Virginia Power's rate adjustment clause filings, differ materially from Virginia Power's expectations, it may adversely affect its results of operations, financial condition and cash flows.

See *Futures Issues and Other Matters* in Item 7. MD&A and Note 13 to the Consolidated Financial Statements for additional information, which is incorporated herein by reference.

Electric Regulation in North Carolina

Virginia Power's retail electric base rates in North Carolina are regulated on a cost-of-service/rate-of-return basis subject to North Carolina statutes and the rules and procedures of the North Carolina Commission. North Carolina base rates are set by a process that allows Virginia Power to recover its operating costs and an ROIC. If retail electric earnings exceed the authorized ROE established by the North Carolina Commission, retail electric rates may be subject to review and possible reduction by the North Carolina Commission, which may decrease Virginia Power's future earnings. Additionally, if the North Carolina Commission does not allow recovery of costs incurred in providing service on a timely basis, Virginia Power's future earnings could be negatively impacted. Fuel rates are subject to revision under annual fuel cost adjustment proceedings.

Virginia Power's transmission service rates in North Carolina are regulated by the North Carolina Commission as part of Virginia Power's bundled retail service to North Carolina customers.

See Note 13 to the Consolidated Financial Statements for additional information, which is incorporated herein by reference.

GAS

Dominion Energy Questar's natural gas development, production, transportation, and distribution services, including the rates it may charge its customers, are regulated by the state commissions of Utah, Wyoming and Idaho. East Ohio's natural gas distribution services, including the rates it may charge its customers, are regulated by the Ohio Commission. Hope's natural gas distribution services are regulated by the West Virginia Commission.

Gas Regulation in Utah, Wyoming and Idaho

Questar Gas is subject to regulation of rates and other aspects of its business by the Utah, Wyoming and Idaho Commissions. The Idaho Commission has contracted with the Utah Commission for rate oversight of Questar Gas' operations in a small area of southeastern Idaho. When necessary, Questar Gas seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates for Questar Gas are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges.

In addition to general rate increases, Questar Gas makes routine separate filings with the Utah and Wyoming Commissions to reflect changes in the costs of purchased gas. The majority of these purchased gas costs are subject to rate recovery through the Wexpro Agreement and Wexpro II Agreement. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas recovery filings generally cover a prospective twelve-month period. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

In connection with the Dominion Energy Questar Combination, Questar Gas withdrew its general rate case filed in July 2016 with the Utah Commission and agreed not to file a general rate case with the Utah Commission to adjust its base distribution non-gas rates prior to July 2019, unless otherwise ordered by the Utah Commission. In addition Questar Gas agreed not to file a general rate case with the Wyoming Commission with a requested rate effective date earlier than January 2020. This does not impact Questar Gas' ability to adjust rates through various riders. See Note 3 to the Consolidated Financial Statements for additional information.

Gas Regulation in Ohio

East Ohio is subject to regulation of rates and other aspects of its business by the Ohio Commission. When necessary, East Ohio seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. A straight-fixed-variable rate design, in which the majority of operating costs are recovered through a monthly charge rather than a volumetric charge, is utilized to establish rates for a majority of East Ohio's customers pursuant to a 2008 rate case settlement.

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In addition to general base rate increases, East Ohio makes routine filings with the Ohio Commission to reflect changes in the costs of gas purchased for operational balancing on its system. These purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The rider filings cover unrecovered gas costs plus prospective annual demand costs. Increases or decreases in gas cost rider rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

The Ohio Commission has also approved several stand-alone cost recovery mechanisms to recover specified costs and a return for infrastructure projects and certain other costs that vary widely over time; such costs are excluded from general base rates. See Note 13 to the Consolidated Financial Statements for additional information.

Gas Regulation in West Virginia

Hope is subject to regulation of rates and other aspects of its business by the West Virginia Commission. When necessary, Hope seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates for Hope are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges.

In addition to general rate increases, Hope makes routine separate filings with the West Virginia Commission to reflect changes in the costs of purchased gas. The majority of these purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas cost recovery filings generally cover a prospective twelve-month period. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

Legislation was passed in West Virginia authorizing a stand-alone cost recovery mechanism to recover specified costs and a return for infrastructure upgrades, replacements and expansions between general base rate cases. See Note 13 to the Consolidated Financial Statements for additional information.

Status of Competitive Retail Gas Services

The states of Ohio and West Virginia, in which Dominion Energy and Dominion Energy Gas have gas distribution operations, have considered legislation regarding a competitive deregulation of natural gas sales at the retail level.

Ohio—Since October 2000, East Ohio has offered the Energy Choice program, under which residential and commercial customers are encouraged to purchase gas directly from retail suppliers or through a community aggregation program. In October 2006, East Ohio restructured its commodity service by entering into gas purchase contracts with selected suppliers at a fixed price above the New York Mercantile Exchange month-end settlement and passing that gas cost to customers under the Standard Service Offer program. Starting in April 2009, East Ohio buys natural gas under the Standard Service Offer program only for customers not eligible to participate in the Energy Choice program and places Energy Choice-eligible customers in a direct retail relationship with selected suppliers, which is designated on the customers' bills.

In January 2013, the Ohio Commission granted East Ohio's motion to fully exit the merchant function for its nonresidential customers, beginning in April 2013, which requires those customers to choose a retail supplier or be assigned to one at a monthly variable rate set by the supplier. At December 31, 2017, approximately 1.0 million of Dominion Energy Gas' 1.2 million Ohio customers were participating in the Energy Choice program. Subject to the Ohio Commission's approval, East Ohio may eventually exit the gas merchant function in Ohio entirely and have all customers select an alternate gas supplier. East Ohio continues to be the provider of last resort in the event of default by a supplier. Large industrial customers in Ohio also source their own natural gas supplies.

West Virginia—At this time, West Virginia has not enacted legislation allowing customers to choose providers in the retail natural gas markets served by Hope. However, the West Virginia Commission has issued regulations to govern pooling services, one of the tools that natural gas suppliers may utilize to provide retail customers a choice in the future and has issued rules requiring competitive gas service providers to be licensed in West Virginia.

Federal Regulations

FEDERAL ENERGY REGULATORY COMMISSION

Electric

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Virginia Power purchases and sells electricity in the PJM wholesale market and Dominion Energy's merchant generators sell electricity in the PJM, MISO, CAISO and ISO-NE wholesale markets, and to wholesale purchasers in the states of Virginia, North Carolina, Indiana, Connecticut, Tennessee, Georgia, California, South Carolina and Utah, under Dominion Energy's market-based sales tariffs authorized by FERC or pursuant to FERC authority to sell as a qualified facility. In addition, Virginia Power has FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside Virginia Power's service territory. Any such sales would be voluntary.

Dominion Energy and Virginia Power are subject to FERC's Standards of Conduct that govern conduct between transmission function employees of interstate gas and electricity transmission providers and the marketing function employees of their affiliates. The rule defines the scope of transmission and marketing-related functions that are covered by the standards and is designed to prevent transmission providers from giving their affiliates undue preferences.

Dominion Energy and Virginia Power are also subject to FERC's affiliate restrictions that (1) prohibit power sales between Virginia Power and Dominion Energy's merchant plants without first receiving FERC authorization, (2) require the merchant plants and Virginia Power to conduct their wholesale power sales operations separately, and (3) prohibit Virginia Power from sharing market information with merchant plant operating personnel. The rules are designed to prohibit Virginia Power from giving the merchant plants a competitive advantage.

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EPACT included provisions to create an ERO. The ERO is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. FERC has certified NERC as the ERO and also issued an initial order approving many reliability standards that went into effect in 2007. Entities that violate standards will be subject to fines of up to $1.2 million per day, per violation and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

Dominion Energy and Virginia Power plan and operate their facilities in compliance with approved NERC reliability requirements. Dominion Energy and Virginia Power employees participate on various NERC committees, track the development and implementation of standards, and maintain proper compliance registration with NERC's regional organizations. Dominion Energy and Virginia Power anticipate incurring additional compliance expenditures over the next several years as a result of the implementation of new cybersecurity programs. In addition, NERC has redefined critical assets which expanded the number of assets subject to NERC reliability standards, including cybersecurity assets. NERC continues to develop additional requirements specifically regarding supply chain standards and control centers that impact the bulk electric system. While Dominion Energy and Virginia Power expect to incur additional compliance costs in connection with NERC requirements and initiatives, such expenses are not expected to significantly affect results of operations.

In April 2008, FERC granted an application for Virginia Power's electric transmission operations to establish a forward-looking formula rate mechanism that updates transmission rates on an annual basis and approved an ROE of 11.4%, effective as of January 1, 2008. The formula rate is designed to recover the expected revenue requirement for each calendar year and is updated based on actual costs. The FERC-approved formula method, which is based on projected costs, allows Virginia Power to earn a current return on its growing investment in electric transmission infrastructure.

Gas

FERC regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, as amended. Under the Natural Gas Act, FERC has authority over rates, terms and conditions of services performed by Dominion Energy Questar Pipeline, DETI, DECG, Iroquois and certain services performed by Cove Point. The design, construction and operation of Cove Point's LNG facility, including associated natural gas pipelines, the Liquefaction Project and the import and export of LNG are also regulated by FERC.

Dominion Energy's and Dominion Energy Gas' interstate gas transmission and storage activities are conducted on an open access basis, in accordance with certificates, tariffs and service agreements on file with FERC and FERC regulations.

Dominion Energy and Dominion Energy Gas operate in compliance with FERC standards of conduct, which prohibit the sharing of certain non-public transmission information or customer specific data by its interstate gas transmission and storage companies with non-transmission function employees. Pursuant to these standards of conduct, Dominion Energy and Dominion Energy Gas also make certain informational postings available on Dominion Energy's website.

See Note 13 to the Consolidated Financial Statements for additional information.

Safety Regulations

Dominion Energy and Dominion Energy Gas are also subject to the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which mandate inspections of interstate and intrastate natural gas transmission and storage pipelines, particularly those located in areas of high-density population. Dominion Energy and Dominion Energy Gas have evaluated their natural gas transmission and storage properties, as required by the Department of Transportation regulations under these Acts, and has implemented a program of identification, testing and potential remediation activities. These activities are ongoing.

The Companies are subject to a number of federal and state laws and regulations, including Occupational Safety and Health Administration, and comparable state statutes, whose purpose is to protect the health and safety of workers. The Companies have an internal safety, health and security program designed to monitor and enforce compliance with worker safety requirements, which is routinely reviewed and considered for improvement. The Companies believe that they are in material compliance with all applicable laws and regulations related to worker health and safety. Notwithstanding these preventive measures, incidents may occur that are outside of the Companies' control.

Environmental Regulations

Each of the Companies' operating segments faces substantial laws, regulations and compliance costs with respect to environmental matters. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the Companies. If compliance expenditures and associated operating costs are not recoverable from customers through regulated rates (in regulated businesses) or market prices (in unregulated businesses), those costs could adversely affect future results of operations and cash flows. The Companies have applied for or obtained the necessary environmental permits for the construction and operation of their facilities. Many of these permits are subject to reissuance and continuing review. For a discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance required to be discussed in this Item, see *Environmental Matters* in *Future Issues and Other Matters* in Item 7. MD&A, which information is incorporated herein by reference. Additional information can also be found in Item 3. Legal Proceedings and Note 22 to the Consolidated Financial Statements, which information is incorporated herein by reference.

AIR

The CAA is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. Regulated emissions include, but are not limited to, carbon, methane, VOC, other GHGs, mercury, other toxic metals,

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hydrogen chloride, NO_X, SO_2, and particulate matter. At a minimum, delegated states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

GLOBAL CLIMATE CHANGE

The national and international attention to GHG emissions and their relationship to climate change has resulted in federal, regional and state legislative and regulatory action in this area. See, for example, the discussion of the Clean Power Plan and the United Nation's Paris Agreement in *Environmental Matters* in *Future Issues and Other* Matters in Item 7. MD&A.

The Companies support national climate change legislation that would provide a consistent, economy-wide approach to addressing this issue and are currently taking action to protect the environment and reduce GHG emissions while meeting the growing needs of their customers. Dominion Energy's CEO and operating segment CEOs are responsible for compliance with the laws and regulations governing environmental matters, including GHG emissions, and Dominion Energy's Board of Directors receives periodic updates on these matters. See *Environmental Strategy* below, *Environmental Matters* in *Future Issues and Other Matters* in Item 7. MD&A and Note 22 to the Consolidated Financial Statements for information on climate change legislation and regulation, which information is incorporated herein by reference.

WATER

The CWA is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. The CWA and analogous state laws impose restrictions and strict controls regarding discharges of effluent into surface waters and require permits to be obtained from the EPA or the analogous state agency for those discharges. Containment berms and similar structures may be required to help prevent accidental releases. Dominion Energy must comply with applicable CWA requirements at its current and former operating facilities. Stormwater related to construction activities is also regulated under the CWA and by state and local stormwater management and erosion and sediment control laws. From time to time, Dominion Energy's projects and operations may impact tidal and non-tidal wetlands. In these instances, Dominion Energy must obtain authorization from the appropriate federal, state and local agencies prior to impacting wetlands. The authorizing agency may impose significant direct or indirect mitigation costs to compensate for such impacts to wetlands.

WASTE AND CHEMICAL MANAGEMENT

Dominion Energy is subject to various federal and state laws and implementing regulations governing the management, storage, treatment, reuse and disposal of waste materials and hazardous substances, including the Resources Conservation and Recovery Act of 1976, CERCLA, the Emergency Planning and Community Right-to-Know Act of 1986 and the Toxic Substance Control Act of 1976. Dominion Energy's operations and construction activities, including activities associated with oil and gas production and gas storage wells, generate waste. Across Dominion Energy, completion water is disposed at commercial disposal facilities. Produced water is either hauled for disposal, evaporated or injected into company and third-party owned underground injection wells. Wells drilled in tight-gas-sand and shale reservoirs require hydraulic-fracture stimulation to achieve economic production rates and recoverable reserves. The majority of Wexpro's current and future production and reserve potential is derived from reservoirs that require hydraulic-fracture stimulation to be commercially viable. Currently, all well construction activities, including hydraulic-fracture stimulation and management and disposal of hydraulic fracturing fluids, are regulated by federal and state agencies that review and approve all aspects of gas- and oil-well design and operation.

PROTECTED SPECIES

The ESA and analogous state laws prohibit activities that can result in harm to specific species of plants and animals, as well as impacts to the habitat on which those species depend. In addition to ESA programs, the MBTA and the BGEPA establish broader prohibitions on harm to protected birds. Many of the Companies' facilities are subject to requirements of the ESA, MBTA and BGEPA. The ESA and BGEPA require potentially lengthy coordination with the state and federal agencies to ensure potentially affected species are protected. Ultimately, the suite of species protections may restrict company activities to certain times of year, project modifications may be necessary to avoid harm, or a permit may be needed to allow for unavoidable taking of the species. The authorizing agency may impose mitigation requirements and costs to compensate for harm of a protected species or habitat loss. These requirements and time of year restrictions can result in adverse impacts on project plans and schedules such that the Companies' businesses may be materially affected.

OTHER REGULATIONS

Other significant environmental regulations to which the Companies are subject include federal and state laws protecting graves, sacred sites, historic sites and cultural resources, including those of American Indian populations. These can result in compliance and mitigation costs, and potential adverse effects on project plans and schedules such that the Companies' businesses may be materially affected.

Nuclear Regulatory Commission

All aspects of the operation and maintenance of Dominion Energy's and Virginia Power's nuclear power stations are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification, and the operation of a nuclear unit may be suspended if the NRC determines that the public interest, health or safety so requires.

From time to time, the NRC adopts new requirements for the operation and maintenance of nuclear facilities. In many cases, these new regulations require changes in the design, operation and maintenance of existing nuclear facilities. If the NRC adopts such requirements in the future, it could result in substantial increases in the cost of operating and maintaining Dominion Energy's and Virginia Power's nuclear generating units. See Note 22 to the Consolidated Financial Statements for further information.

The NRC also requires Dominion Energy and Virginia Power to decontaminate their nuclear facilities once operations cease.

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This process is referred to as decommissioning, and Dominion Energy and Virginia Power are required by the NRC to be financially prepared. For information on decommissioning trusts, see *Power Generation-Nuclear Decommissioning* above and Note 9 to the Consolidated Financial Statements. See Note 22 to the Consolidated Financial Statements for information on spent nuclear fuel.

ENVIRONMENTAL STRATEGY

As part of the Companies' overall long term strategic planning overseen by the Board of Directors, we have a well formed environmental strategy. The Companies are committed to continuing to be an industry leader, delivering safe, reliable, clean and affordable energy while fully complying with all applicable environmental laws and regulations. Additionally, we seek to build partnerships and engage with local communities, stakeholders and customers on environmental issues important to them. The Companies are dedicated to meeting their customers' growing energy needs with innovative, sustainable solutions. It is the Companies' belief that sustainable solutions should strive to balance the interdependent goals of environmental stewardship and economic effects. The integrated strategy to meet these objectives consists of three major elements:

- Reduction of GHG emissions;
- Energy infrastructure modernization, including natural gas and electric operations; and
- Conservation and energy efficiency.

Reduction of GHG Emissions

The Companies integrated strategy has resulted in a reduction in GHG emission intensity. Over the past two decades, the Companies have made changes to the generation mix and to natural gas operations which have significantly improved environmental performance. For example, Power Generation has significantly reduced both its carbon emissions and its carbon intensity while generating electricity with an increasingly clean portfolio. From 2000 through 2016, our carbon intensity decreased by 43%. This strategy has also resulted in significant reductions of other air pollutants such as NO_X, SO_2 and mercury and also reduced the amount of coal ash generated and the amount of water withdrawn. The principal components of the strategy, which include initiatives that address electric energy production and delivery, natural gas storage, transmission and delivery and energy management, are as follows:

- Expand Dominion Energy's and Virginia Power's renewable energy portfolio, including solar, wind power, and biomass, to further diversify Dominion Energy's and Virginia Power's fleet, meet state renewable energy targets and lower the carbon footprint;
- Pursue the extension of operating licenses of existing nuclear units which provide carbon-free generation;
- Evaluate effective battery solutions, such as hydroelectric pumped storage, which help support a grid with increased renewables;
- Enhance conservation and energy efficiency programs on both the electric and gas side of our businesses to help customers use energy wisely and reduce environmental impacts;
- Sell, close, place in cold reserve or convert to cleaner fuels a number of coal-fired generation units owned by Dominion Energy and Virginia Power;
- Evaluate behind-the-meter and rate design solutions and other business opportunities;
- Construct new electric and gas transmission infrastructure to modernize the grid, to expand availability of cleaner fuel, to reduce emissions, to promote energy and economic security and help deliver more green energy to population centers where it is needed most;
- Replace older distribution pipeline mains and services; and
- Implement and enhance voluntary methane mitigation measures through participation in the EPA's Natural Gas Star and Methane Challenge programs; and continue to evaluate business opportunities presented by a lower carbon economy and innovative technologies.

See *Operating Segments* for more information on certain of the projects described above.

CLEANER GENERATION

Renewable energy is an important component of a diverse and reliable energy mix that helps to mitigate the environmental aspects of energy production. Nationally, Dominion Energy has nearly 2,400 MW of renewable generating capacity in operation or under development in nine states, including offtake agreements for Virginia Power's utility customers. Both Virginia and North Carolina have passed legislation setting targets for renewable power. Dominion Energy is committed to meeting Virginia's goals of 12% of base year electric energy sales from renewable power sources by 2022, and 15% by 2025, and North Carolina's Renewable Portfolio Standard of 12.5% by 2021 and continues to add utility-scale solar capacity. Backed by a $1 billion investment, Dominion Energy has grown its solar fleet in Virginia and North Carolina over the past two years from near zero to about 1,350 megawatts in service, in construction or under development.

See *Operating Segments* and Item 2. Properties for additional information, including Dominion Energy's merchant solar properties.

GHG EMISSIONS

Since 2000, Dominion Energy and Virginia Power have tracked the emissions of their electric generation fleet, which employs a mix of fuel and renewable energy sources. Comparing annual year 2016 to annual year 2000, the entire electric generating fleet (based on ownership percentage) reduced its average CO_2 emissions rate per MWh of energy produced from electric generation by approximately 43%. Comparing annual year 2016 to annual year 2000, the regulated electric generating fleet (based on ownership percentage) reduced its average CO_2 emissions rate per MWh of energy produced from electric generation by approximately 26%.

Dominion Energy also develops a comprehensive GHG inventory annually. For Power Generation, Dominion Energy and Virginia Power's direct CO_2 equivalent emissions, based on ownership percentage, were 37.2 million metric tons and 33.1 million metric tons, respectively, in 2016, compared to 34.3 million metric tons and 30.9 million metric tons, respectively, in 2015. The corresponding carbon intensity rates for Dominion Energy were 0.339 metric tons CO_2 equivalent

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emissions per net MWh in 2016 and 0.348 metric tons CO_2 equivalent emissions per net MWh in 2015.

For Power Delivery's regulated electric transmission and distribution operations, direct CO_2 equivalent emissions for 2016 were 42,856 metric tons, compared to 53,819 metric tons in 2015.

Dominion Energy's natural gas companies have been reporting GHG emissions to the EPA since 2011 under the GHG Reporting Program. In January 2016, the GHG Reporting Program was expanded to also include GHG inputs and emissions associated with natural gas gathering and boosting sources and transmission pipeline blowdowns for facilities that exceed 25,000 metric tons per year of CO_2 equivalent emissions. The sources within these new facilities were not previously covered under the rule and the first reports for these new sources were submitted to EPA on March 31, 2017.

Hope and East Ohio direct CO_2 equivalent emissions together decreased from 0.90 million metric tons in 2015 to 0.86 million metric tons in 2016. DETI's and Cove Point's direct CO_2 equivalent emissions together were 1.3 million metric tons in 2016, increasing from 1.1 million metric tons in 2015 attributable to new EPA reporting of transmission pipeline blowdowns.

The Companies' GHG inventory follows all methodologies specified in the EPA Mandatory Greenhouse Gas Reporting Rule, 40 Code of Federal Regulations Part 98 for calculating emissions. Total CO_2 equivalent emissions reported for our natural gas assets, as estimated in Dominion Energy's corporate inventory, were 2.3 million metric tons in 2016. This estimate includes emissions reported under the GHG Reporting Program, as well as other emissions not required to be reported under the federal program. The 2016 corporate GHG inventory emission estimate includes Dominion Energy Questar Pipeline, Questar Gas and Wexpro for the entire calendar year.

Energy Infrastructure Modernization

Dominion Energy's existing five-year investment plan includes significant capital expenditures to upgrade or add new electric transmission and distribution lines, substations and other facilities to meet growing electricity demand within its service territory, maintain reliability, implement a strategic underground program to minimize outage duration and address environmental requirements. These enhancements are primarily aimed at meeting Dominion Energy's continued goal of providing reliable service, and are intended to address both continued population growth and increases in electricity consumption. An additional benefit will be added capacity to efficiently deliver electricity from the renewable projects now being developed, or to be developed in the future, to meet our customers' preference for cleaner energy. See *Operating Segments* for additional information.

The Companies have also implemented infrastructure improvements and improved operational practices to reduce the GHG emissions from our natural gas facilities. Dominion Energy and Dominion Energy Gas, in connection with their existing five-year investment plans, are also pursuing the construction or upgrade of regulated infrastructure in their natural gas businesses. The Companies have made voluntary commitments as part of the EPA Methane Challenge Program to continue to reduce methane emissions as part of these improvements. See *Operating Segments* for additional information, including natural gas infrastructure projects.

Conservation and Energy Efficiency

Conservation and load management play a significant role in meeting the growing demand for electricity and natural gas, while also helping to reduce the environmental footprint of our customers.

The Regulation Act provides incentives for energy conservation through the implementation of conservation programs. Additional legislation in 2009 added definitions of peak-shaving and energy efficiency programs, and allowed for a margin on operating expenses and recovery of revenue reductions related to energy efficiency programs.

Virginia Power's DSM programs, implemented with Virginia Commission and North Carolina Commission approval, provide important incremental steps in assisting customers to reduce energy consumption through programs that include energy audits and incentives for customers to upgrade or install certain energy efficient measures and/or systems. The DSM programs began in Virginia in 2010 and in North Carolina in 2011. Currently, there are residential and non-residential DSM programs active in the two states. Virginia Power continues to evaluate opportunities to redesign current DSM programs and develop new DSM initiatives in Virginia and North Carolina.

Virginia Power continues to upgrade meters throughout Virginia to AMI, also referred to as smart meters. The AMI meter upgrades are part of an ongoing demonstration effort to help Virginia Power further evaluate the effectiveness of AMI meters to monitor voltage stability, remotely turn off and on electric service, increase detection and reporting capabilities with respect to power outages and restorations, obtain remote daily meter readings and offer dynamic rates.

East Ohio offers two DSM programs, approved by the Ohio Commission, designed to help customers reduce their energy consumption. One program provides weatherization assistance to help income-eligible customers reduce their energy usage. Another program has been designed to help East Ohio's residential customers improve their homes' energy efficiency, starting with a home energy assessment. Following the assessment, customers receive a report with recommendations on how to save energy and improve their home's comfort. This program includes rebates and free installation of several energy-efficient products such as, high-efficiency showerheads, kitchen and bathroom faucet aerators, programmable thermostat or carbon monoxide detector and water heater pipe wrap.

Questar Gas offers an energy-efficiency program, approved by the Utah and Wyoming Commissions, designed to help customers reduce their energy consumption. This program promotes the use of energy-efficient appliances and practices to reduce natural gas usage. The program provides home energy planning, which provides homeowners with a step-by-step roadmap to efficiency improvements to reduce gas usage. In addition to the recommendations, the program provides home owners with energy-saving devices such as pipe insulation and low-flow shower heads as well as rebates on appliances and weatherization items. The program also offers new construction builders with rebates for installing high-efficiency equipment and offers commercial businesses with rebates on energy efficient equipment and retrofits.

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CYBERSECURITY

In an effort to reduce the likelihood and severity of cyber intrusions, the Companies have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of data and systems. In addition, the Companies are subject to mandatory cybersecurity regulatory requirements, interface regularly with a wide range of external organizations, and participate in classified briefings to maintain an awareness of current cybersecurity threats and vulnerabilities. The Companies' current security posture and regulatory compliance efforts are intended to address the evolving and changing cyber threats. See Item 1A. Risk Factors for additional information.

Item 1A. Risk Factors

The Companies' businesses are influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. A number of these factors have been identified below. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in Item 7. MD&A.

The Companies' results of operations can be affected by changes in the weather. Fluctuations in weather can affect demand for the Companies' services. For example, milder than normal weather can reduce demand for electricity and gas transmission and distribution services. In addition, severe weather, including hurricanes, winter storms, earthquakes, floods and other natural disasters can disrupt operation of the Companies' facilities and cause service outages, production delays and property damage that require incurring additional expenses. Changes in weather conditions can result in reduced water levels or changes in water temperatures that could adversely affect operations at some of the Companies' power stations. Furthermore, the Companies' operations could be adversely affected and their physical plant placed at greater risk of damage should changes in global climate produce, among other possible conditions, unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, abnormal levels of precipitation and, for operations located on or near coastlines, a change in sea level or sea temperatures.

The rates of Dominion Energy's and Dominion Energy Gas' gas transmission and distribution operations and Virginia Power's electric transmission, distribution and generation operations are subject to regulatory review. Revenue provided by Virginia Power's electric transmission, distribution and generation operations and Dominion Energy's and Dominion Energy Gas' gas transmission and distribution operations is based primarily on rates approved by state and federal regulatory agencies. However, certain large scale customers are able to enter into negotiated-rate contracts rather than pay cost-of-service rates which are subject to regulatory review. The profitability of these businesses is dependent on their ability, through the rates that they are permitted to charge, to recover costs and earn a reasonable rate of return on their capital investment.

Virginia Power's wholesale rates for electric transmission service are updated on an annual basis through operation of a FERC-approved formula rate mechanism. Through this mechanism, Virginia Power's wholesale rates for electric transmission reflect the estimated cost-of-service for each calendar year. The difference in the estimated cost-of-service and actual cost-of-service for each calendar year is included as an adjustment to the wholesale rates for electric transmission service in a subsequent calendar year. These wholesale rates are subject to FERC review and prospective adjustment in the event that customers and/or interested state commissions file a complaint with FERC and are able to demonstrate that Virginia Power's wholesale revenue requirement is no longer just and reasonable. They are also subject to retroactive corrections to the extent that the formula rate was not properly populated with the actual costs.

Similarly, various rates and charges assessed by Dominion Energy's and Dominion Energy Gas' gas transmission businesses are subject to review by FERC. In addition, the rates of Dominion Energy's and Dominion Energy Gas' gas distribution businesses are subject to state regulatory review in the jurisdictions in which they operate. A failure by Dominion Energy or Dominion Energy Gas to support these rates could result in rate decreases from current rate levels, which could adversely affect Dominion Energy's and Dominion Energy Gas' results of operations, cash flows and financial condition.

Virginia Power's base rates, terms and conditions for generation and distribution services to customers in Virginia are reviewed by the Virginia Commission on a biennial basis in a proceeding that involves the determination of Virginia Power's actual earned ROE during a combined two-year historic test period, and the determination of Virginia Power's authorized ROE prospectively. Under certain circumstances described in the Regulation Act, Virginia Power may be required to share a portion of its earnings with customers through a refund process.

Legislation signed by the Virginia Governor in February 2015 suspends biennial reviews for the five successive 12-month test periods beginning January 1, 2015 and ending December 31, 2019, and no changes will be made to Virginia Power's existing base rates until at least December 1, 2022. During this period, Virginia Power bears the risk of any severe weather events and natural disasters, the risk of asset impairments related to the early retirement of any generation facilities due to the implementation of environmental regulations, as well as an increase in general operating and financing costs, and Virginia Power may not recover its associated costs through increases to base rates. If Virginia Power incurs any such significant additional expenses during this period, Virginia Power may not be able to recover its costs and/or earn a reasonable return on capital investment, which could negatively affect Virginia Power's future earnings.

Virginia Power's retail electric base rates for bundled generation, transmission, and distribution services to customers in North Carolina are regulated on a cost-of-service/rate-of-return basis subject to North Carolina statutes, and the rules and procedures of the North Carolina Commission. If retail electric earnings exceed the returns established by the North Carolina Commission, retail electric rates may be subject to review and possible reduction by the North Carolina Commission, which may decrease Virginia Power's future earnings. Additionally, if the North Carolina Commission does not allow recovery through

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base rates, on a timely basis, of costs incurred in providing service, Virginia Power's future earnings could be negatively impacted.

Governmental officials, stakeholders and advocacy groups may challenge these regulatory reviews. Such challenges may lengthen the time, complexity and costs associated with such regulatory reviews.

The Companies are subject to complex governmental regulation, including tax regulation, that could adversely affect their results of operations and subject the Companies to monetary penalties. The Companies' operations are subject to extensive federal, state and local regulation and require numerous permits, approvals and certificates from various governmental agencies. Such laws and regulations govern the terms and conditions of the services we offer, our relationships with affiliates, protection of our critical electric infrastructure assets and pipeline safety, among other matters. These operations are also subject to legislation governing taxation at the federal, state and local level. They must also comply with environmental legislation and associated regulations. Management believes that the necessary approvals have been obtained for existing operations and that the business is conducted in accordance with applicable laws. The Companies' businesses are subject to regulatory regimes which could result in substantial monetary penalties if any of the Companies is found not to be in compliance, including mandatory reliability standards and interaction in the wholesale markets. New laws or regulations, the revision or reinterpretation of existing laws or regulations, changes in enforcement practices of regulators, or penalties imposed for non-compliance with existing laws or regulations may result in substantial additional expense. Recent legislative and regulatory changes that are impacting the Companies include the 2017 Tax Reform Act and tariffs imposed on imported solar panels by the U.S. government in 2018.

The 2017 Tax Reform Act could have a material impact on our operations, cash flows, and financial results. Reductions in the estimated annual cost-of-service effect (commonly referred to as the gross-up factor) due to the reduction in the corporate income tax rates to 21% under the provisions of the 2017 Tax Reform Act could result in amounts currently collected from utility customers to be refundable to such customers, generally through reductions in rates. In addition, the Companies' regulators may require the reduction in accumulated deferred income tax balances under the provisions of the 2017 Tax Reform Act to be shared with customers, generally through reductions in future rates. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes may be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred taxes may be determined by our federal and state regulators.

The 2017 Tax Reform Act could have a material impact on Dominion Energy and Dominion Energy Gas' FERC-regulated gas operations including rates charged to customers. In light of the reduction in the income tax rate in the 2017 Tax Reform Act, our FERC-regulated gas subsidiaries are subject to an increased risk of FERC initiating industry-wide proceedings under Section 5 of the Natural Gas Act to have interstate pipelines substantiate rates charged for transportation and storage of natural gas in interstate commerce, when viewed holistically, are "just and reasonable" taking into account the effects of tax reform and all other drivers. It is unclear if FERC will mandate a one-time rate reset or Section 5 rate case for Dominion Energy and Dominion Energy Gas' regulated subsidiaries; however, states as well as customers have petitioned FERC to request changes in rates as a result of tax reform.

The interpretation of provisions of the 2017 Tax Reform Act that take effect in 2018 may significantly impact our operations. The 2017 Tax Reform Act contains provisions that limit the deductibility of interest expense. The new provision generally limits the interest deduction on business interest to (1) business interest income, plus (2) 30 percent of the taxpayer's adjusted taxable income. Business interest and business interest income is defined as that allocable to a trade or business and not investment interest and income. Regulated public utilities are not subject to this interest limitation; however Dominion Energy is a consolidated group with both regulated and merchant lines of businesses. The U.S. Department of Treasury has been tasked with providing guidance on applying the interest limitation to consolidated groups, such as Dominion Energy, but it is unclear when that guidance may be issued, or whether that guidance could result in a disallowance of a portion of our interest deductions in the future.

Dominion Energy and Virginia Power's generation business may be negatively affected by possible FERC actions that could change market design in the wholesale markets or affect pricing rules or revenue calculations in the RTO markets. Dominion Energy and Virginia Power's generation stations operating in RTO markets sell capacity, energy and ancillary services into wholesale electricity markets regulated by FERC. The wholesale markets allow these generation stations to take advantage of market price opportunities, but also expose them to market risk. Properly functioning competitive wholesale markets depend upon FERC's continuation of clearly identified market rules. From time to time FERC may investigate and authorize RTOs to make changes in market design. FERC also periodically reviews Dominion Energy's authority to sell at market-based rates. Material changes by FERC to the design of the wholesale markets or its interpretation of market rules, Dominion Energy or Virginia Power's authority to sell power at market-based rates, or changes to pricing rules or rules involving revenue calculations, could adversely impact the future results of Dominion Energy or Virginia Power's generation business. For example, in July 2015, FERC approved changes to PJM's Reliability Pricing Model capacity market establishing a new Capacity Performance Resource product. This product offers the potential for higher capacity prices but can also impose significant economic penalties on generator owners such as Virginia Power for failure to perform during periods when electricity is in high demand. In addition, there have been changes to the interpretation and application of FERC's market manipulation rules. A failure to comply with these rules could lead to civil and criminal penalties.

The Companies' infrastructure build and expansion plans often require regulatory approval before construction can commence. The Companies may not complete facility construction, pipeline, conversion or other infrastructure projects that they commence, or they may complete projects on materially different terms or timing than initially anticipated, and they may not be able to achieve the intended benefits of any such project, if completed. Several facility construction, pipeline, electric transmission line, expansion, conversion and other infrastructure projects have been announced and additional projects

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may be considered in the future. The Companies compete for projects with companies of varying size and financial capabilities, including some that may have competitive advantages. Commencing construction on announced and future projects may require approvals from applicable state and federal agencies, and such approvals could include mitigation costs which may be material to the Companies. Projects may not be able to be completed on time as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties, difficulties with partners or potential partners, a decline in the credit strength of counterparties or vendors, or other factors beyond the Companies' control. Even if facility construction, pipeline, expansion, electric transmission line, conversion and other infrastructure projects are completed, the total costs of the projects may be higher than anticipated and the performance of the business of the Companies following completion of the projects may not meet expectations. Start-up and operational issues can arise in connection with the commencement of commercial operations at our facilities, including but not limited to commencement of commercial operations at our power generation facilities following expansions and the Liquefaction Project. Such issues may include failure to meet specific operating parameters, which may require adjustments to meet or amend these operating parameters. Additionally, the Companies may not be able to timely and effectively integrate the projects into their operations and such integration may result in unforeseen operating difficulties or unanticipated costs. Further, regulators may disallow recovery of some of the costs of a project if they are deemed not to be prudently incurred. Any of these or other factors could adversely affect the Companies' ability to realize the anticipated benefits from the facility construction, pipeline, electric transmission line, expansion, conversion and other infrastructure projects.

The development, construction and commissioning of several large-scale infrastructure projects simultaneously involves significant execution risk. The Companies are currently simultaneously developing, constructing or commissioning several major projects, including the Liquefaction Project, the Atlantic Coast Pipeline Project, the Supply Header project, Greensville County and multiple DETI projects, which together help contribute to the over $25 billion in capital expenditures planned by the Companies through 2022. Several of the Companies' key projects are increasingly large-scale, complex and being constructed in constrained geographic areas or in difficult terrain, for example, the Atlantic Coast Pipeline Project. The advancement of the Companies' ventures is also affected by the interventions, litigation or other activities of stakeholder and advocacy groups, some of which oppose natural gas-related and energy infrastructure projects. For example, certain landowners and stakeholder groups oppose the Atlantic Coast Pipeline Project, which could impede construction activities or the acquisition of rights-of-way and other land rights on a timely basis or on acceptable terms. Given that these projects provide the foundation for the Companies' strategic growth plan, if the Companies are unable to obtain or maintain the required approvals, develop the necessary technical expertise, allocate and coordinate sufficient resources, adhere to budgets and timelines, effectively handle public outreach efforts, or otherwise fail to successfully execute the projects, there could be an adverse impact to the Companies' financial position, results of operations and cash flows. For example, while Dominion Energy has received the required approvals to commence construction of the Liquefaction Project from the DOE, all DOE export licenses are subject to review and possible withdrawal should the DOE conclude that such export authorization is no longer in the public interest. Failure to comply with regulatory approval conditions or an adverse ruling in any future litigation could adversely affect the Companies' ability to execute their business plan.

The Companies are dependent on their contractors for the successful and timely completion of large-scale infrastructure projects. The construction of such projects is expected to take several years, is typically confined within a limited geographic area or difficult terrain and could be subject to delays, cost overruns, labor disputes and other factors that could cause the total cost of the project to exceed the anticipated amount and adversely affect the Companies' financial performance and/or impair the Companies' ability to execute the business plan for the project as scheduled.

Further, an inability to obtain financing or otherwise provide liquidity for the projects on acceptable terms could negatively affect the Companies' financial condition, cash flows, the projects' anticipated financial results and/or impair the Companies' ability to execute the business plan for the projects as scheduled.

The Companies' operations and construction activities are subject to a number of environmental laws and regulations which impose significant compliance costs to the Companies. The Companies' operations and construction activities are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources, and health and safety. Compliance with these legal requirements requires the Companies to commit significant capital toward permitting, emission fees, environmental monitoring, installation and operation of environmental control equipment and purchase of allowances and/or offsets. Additionally, the Companies could be responsible for expenses relating to remediation and containment obligations, including at sites where they have been identified by a regulatory agency as a potentially responsible party. Expenditures relating to environmental compliance have been significant in the past, and the Companies expect that they will remain significant in the future. Certain facilities have become uneconomical to operate and have been shut down, converted to new fuel types or sold. These types of events could occur again in the future.

We expect that existing environmental laws and regulations may be revised and/or new laws may be adopted including regulation of GHG emissions which could have an impact on the Companies' business. Risks relating to expected regulation of GHG emissions from existing fossil fuel-fired electric generating units are discussed below. In addition, further regulation of air quality and GHG emissions under the CAA have been imposed on the natural gas sector, including rules to limit methane leakage. The Companies are also subject to federal water and waste regulations, including regulations concerning cooling water intake structures, coal combustion by-product handling and disposal practices, wastewater discharges from steam electric generating stations, management and disposal of hydraulic fracturing fluids and the potential further regulation of polychlorinated biphenyls.

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Compliance costs cannot be estimated with certainty due to the inability to predict the requirements and timing of implementation of any new environmental rules or regulations. Other factors which affect the ability to predict future environmental expenditures with certainty include the difficulty in estimating clean-up costs and quantifying liabilities under environmental laws that impose joint and several liabilities on all responsible parties. However, such expenditures, if material, could make the Companies' facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect the Companies' results of operations, financial performance or liquidity.

Any additional federal and/or state requirements imposed on energy companies mandating limitations on GHG emissions or requiring efficiency improvements may result in compliance costs that alone or in combination could make some of the Companies' electric generation units or natural gas facilities uneconomical to maintain or operate. The Clean Power Plan, targeted at reducing CO_2 emissions from existing fossil fuel-fired power generation facilities, has been stayed and is being reviewed by the EPA. Compliance with a replacement rule for the Clean Power Plan, or similar regulations, are expected to require increasing the energy efficiency of equipment at facilities, committing significant capital toward carbon reduction programs, purchase of allowances and/or emission rate credits, fuel switching, and/or retirement of high-emitting generation facilities and potential replacement with lower emitting generation facilities. In the absence of federal legislation, states are also contemplating regulations regarding GHG emissions. For example, the Virginia General Assembly has considered legislation which would authorize the state to directly join the RGGI program as a full participant. Given these developments and uncertainties, Dominion Energy and Virginia Power cannot estimate the aggregate effect of such requirements on their results of operations, financial condition or their customers. However, such expenditures, if material, could make Dominion Energy's and Virginia Power's generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect Dominion Energy's or Virginia Power's results of operations, financial performance or liquidity.

There are also potential impacts on Dominion Energy's and Dominion Energy Gas' natural gas businesses as federal or state GHG regulations may require GHG emission reductions from the natural gas sector which, in addition to resulting in increased costs, could affect demand for natural gas. Additionally, GHG requirements could result in increased demand for energy conservation and renewable products, which could impact the natural gas businesses.

Virginia Power is subject to risks associated with the disposal and storage of coal ash. Virginia Power historically produced and continues to produce coal ash, or CCRs, as a by-product of its coal-fired generation operations. The ash is stored and managed in impoundments (ash ponds) and landfills located at eight different facilities.

Virginia Power is facing litigation regarding alleged CWA violations at Chesapeake power station, and may face litigation concerning its coal ash facilities at other stations. Depending on the final outcome of any such litigation, Virginia Power could incur expenses and other costs, including costs associated with closing, corrective action and ongoing monitoring of certain ash ponds. In addition, the EPA has issued regulations concerning the management and storage of CCRs, which Virginia has adopted. These CCR regulations require Virginia Power to make additional capital expenditures and increase its operating and maintenance expenses.

Further, while Virginia Power operates its ash ponds and landfills in compliance with applicable state safety regulations, a release of coal ash with a significant environmental impact, such as the Dan River ash basin release by a neighboring utility, could result in remediation costs, civil and/or criminal penalties, claims, litigation, increased regulation and compliance costs, and reputational damage, and could impact the financial condition of Virginia Power.

The Companies' operations are subject to operational hazards, equipment failures, supply chain disruptions and personnel issues which could negatively affect the Companies. Operation of the Companies' facilities involves risk, including the risk of potential breakdown or failure of equipment or processes due to aging infrastructure, fuel supply, pipeline integrity or transportation disruptions, accidents, labor disputes or work stoppages by employees, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, and performance below expected levels. The Companies' businesses are dependent upon sophisticated information technology systems and network infrastructure, the failure of which could prevent them from accomplishing critical business functions. Because the Companies' transmission facilities, pipelines and other facilities are interconnected with those of third parties, the operation of their facilities and pipelines could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of the Companies' facilities below expected capacity levels could result in lost revenues and increased expenses, including higher maintenance costs. Unplanned outages of the Companies' facilities and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of the Companies' business. Unplanned outages typically increase the Companies' operation and maintenance expenses and may reduce their revenues as a result of selling less output or may require the Companies to incur significant costs as a result of operating higher cost units or obtaining replacement output from third parties in the open market to satisfy forward energy and capacity or other contractual obligations. Moreover, if the Companies are unable to perform their contractual obligations, penalties or liability for damages could result.

In addition, there are many risks associated with the Companies' operations and the transportation, storage and processing of natural gas and NGLs, including nuclear accidents, fires, explosions, uncontrolled release of natural gas and other environmental hazards, pole strikes, electric contact cases, the collision of third party equipment with pipelines and avian and other wildlife impacts. Such incidents could result in loss of human life or injuries among employees, customers or the public in general, environmental pollution, damage or destruction of facilities or business interruptions and associated public or employee safety impacts, loss of revenues, increased liabilities, heightened regulatory scrutiny and reputational risk. Further, the location of pipelines and storage facilities, or generation, transmission, substations and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks.

Dominion Energy and Virginia Power have substantial ownership interests in and operate nuclear generating units; as a result, each may incur substantial costs and liabilities. Dominion Energy's and Virginia Power's nuclear facilities are subject to operational, environmental, health and financial risks such as the on-site storage of spent nuclear fuel, the ability to dispose of such spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, limitations on the amounts and types of insurance available, potential operational liabilities and extended outages, the costs of replacement power, the costs of maintenance and the costs of securing the facilities against possible terrorist attacks. Dominion Energy and Virginia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that future decommissioning costs could exceed amounts in the decommissioning trusts and/or damages could exceed the amount of insurance coverage. If Dominion Energy's and Virginia Power's decommissioning trust funds are insufficient, and they are not allowed to recover the additional costs incurred through insurance, or in the case of Virginia Power through regulatory mechanisms, their results of operations could be negatively impacted.

Dominion Energy's and Virginia Power's nuclear facilities are also subject to complex government regulation which could negatively impact their results of operations. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, depending on its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require Dominion Energy and Virginia Power to make substantial expenditures at their nuclear plants. In addition, although the Companies have no reason to anticipate a serious nuclear incident at their plants, if an incident did occur, it could materially and adversely affect their results of operations and/or financial condition. A major incident at a nuclear facility anywhere in the world, such as the nuclear events in Japan in 2011, could cause the NRC to adopt increased safety regulations or otherwise limit or restrict the operation or licensing of domestic nuclear units.

Sustained declines in natural gas and NGL prices have resulted in, and could result in further, curtailments of third-party producers' drilling programs, delaying the production of volumes of natural gas and NGLs that Dominion Energy and Dominion Energy Gas gather, process, and transport and reducing the value of NGLs retained by Dominion Energy Gas, which may adversely affect Dominion Energy and Dominion Energy Gas' revenues and earnings. Dominion Energy and Dominion Energy Gas obtain their supply of natural gas and NGLs from numerous third-party producers. Most producers are under no obligation to deliver a specific quantity of natural gas or NGLs to Dominion Energy's and Dominion Energy Gas' facilities. A number of other factors could reduce the volumes of natural gas and NGLs available to Dominion Energy's and Dominion Energy Gas' pipelines and other assets. Increased regulation of energy extraction activities could result in reductions in drilling for new natural gas wells, which could decrease the volumes of natural gas supplied to Dominion Energy and Dominion Energy Gas. Producers with direct commodity price exposure face liquidity constraints, which could present a credit risk to Dominion Energy and Dominion Energy Gas. Producers could shift their production activities to regions outside Dominion Energy's and Dominion Energy Gas' footprint. In addition, the extent of natural gas reserves and the rate of production from such reserves may be less than anticipated. If producers were to decrease the supply of natural gas or NGLs to Dominion Energy's and Dominion Energy Gas' systems and facilities for any reason, Dominion Energy and Dominion Energy Gas could experience lower revenues to the extent they are unable to replace the lost volumes on similar terms. In addition, Dominion Energy Gas' revenue from processing and fractionation operations largely results from the sale of commodities at market prices. Dominion Energy Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion Energy Gas to commodity price risk for the value of the spread between the NGL products and natural gas, and relative changes in these prices could adversely impact Dominion Energy Gas' results.

Dominion Energy's merchant power business operates in a challenging market, which could adversely affect its results of operations and future growth. The success of Dominion Energy's merchant power business depends upon favorable market conditions including the ability to sell power at prices sufficient to cover its operating costs. Dominion Energy operates in active wholesale markets that expose it to price volatility for electricity and fuel as well as the credit risk of counterparties. Dominion Energy attempts to manage its price risk by entering into hedging transactions, including short-term and long-term fixed price sales and purchase contracts.

In these wholesale markets, the spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. In many cases, the next unit of electricity supplied would be provided by generating stations that consume fossil fuels, primarily natural gas. Consequently, the open market wholesale price for electricity generally reflects the cost of natural gas plus the cost to convert the fuel to electricity. Therefore, changes in the price of natural gas generally affect the open market wholesale price of electricity. To the extent Dominion Energy does not enter into long-term power purchase agreements or otherwise effectively hedge its output, these changes in market prices could adversely affect its financial results.

Dominion Energy purchases fuel under a variety of terms, including long-term and short-term contracts and spot market purchases. Dominion Energy is exposed to fuel cost volatility for the portion of its fuel obtained through short-term contracts or on the spot market, including as a result of market supply shortages. Fuel prices can be volatile and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs, thus adversely impacting Dominion Energy's financial results.

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In addition, in the event that any of the merchant generation facilities experience a forced outage, Dominion Energy may not receive the level of revenue it anticipated.

The Companies' financial results can be adversely affected by various factors driving supply and demand for electricity and gas and related services. Technological advances required by federal laws mandate new levels of energy efficiency in end-use devices, including lighting, furnaces and electric heat pumps and could lead to declines in per capita energy consumption. Additionally, certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by a fixed date. Further, Virginia Power's business model is premised upon the cost efficiency of the production, transmission and distribution of large-scale centralized utility generation. However, advances in distributed generation technologies, such as solar cells, gas microturbines and fuel cells, may make these alternative generation methods competitive with large-scale utility generation, and change how customers acquire or use our services. Virginia Power has an exclusive franchise to serve retail electric customers in Virginia. However, Virginia's Retail Access Statutes allow certain Power Generation customers exceptions to this franchise. As market conditions change, Virginia Power's customers may further pursue exceptions and Virginia Power's exclusive franchise may erode.

Reduced energy demand or significantly slowed growth in demand due to customer adoption of energy efficient technology, conservation, distributed generation, regional economic conditions, or the impact of additional compliance obligations, unless substantially offset through regulatory cost allocations, could adversely impact the value of the Companies' business activities.

Dominion Energy Gas has experienced a decline in demand for certain of its processing services due to competing facilities operating in nearby areas.

Dominion Energy and Dominion Energy Gas may not be able to maintain, renew or replace their existing portfolio of customer contracts successfully, or on favorable terms. Upon contract expiration, customers may not elect to re-contract with Dominion Energy and Dominion Energy Gas as a result of a variety of factors, including the amount of competition in the industry, changes in the price of natural gas, their level of satisfaction with Dominion Energy's and Dominion Energy Gas' services, the extent to which Dominion Energy and Dominion Energy Gas are able to successfully execute their business plans and the effect of the regulatory framework on customer demand. The failure to replace any such customer contracts on similar terms could result in a loss of revenue for Dominion Energy and Dominion Energy Gas and related decreases in their earnings and cash flows.

Certain of Dominion Energy and Dominion Energy Gas' gas pipeline services are subject to long-term, fixed-price "negotiated rate" contracts that are not subject to adjustment, even if the cost to perform such services exceeds the revenues received from such contracts. Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate" which may be above or below the FERC regulated, cost-based recourse rate for that service. These "negotiated rate" contracts are not generally subject to adjustment for increased costs which could be produced by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue as a result of these "negotiated rate" contracts could decrease Dominion Energy and Dominion Energy Gas' earnings and cash flows.

Exposure to counterparty performance may adversely affect the Companies' financial results of operations. The Companies are exposed to credit risks of their counterparties and the risk that one or more counterparties may fail or delay the performance of their contractual obligations, including but not limited to payment for services. Some of Dominion Energy's operations are conducted through less than wholly-owned subsidiaries. In such arrangements, Dominion Energy is dependent on third parties to fund their required share of capital expenditures. Counterparties could fail or delay the performance of their contractual obligations for a number of reasons, including the effect of regulations on their operations. Defaults or failure to perform by customers, suppliers, contractors, joint venture partners, financial institutions or other third parties may adversely affect the Companies' financial results.

Dominion Energy will also be exposed to counterparty credit risk relating to the terminal services agreements for the Liquefaction Project. While the counterparties' obligations are supported by parental guarantees and letters of credit, there is no assurance that such credit support would be sufficient to satisfy the obligations in the event of a counterparty default. In addition, if a controversy arises under either agreement resulting in a judgment in Dominion Energy's favor, Dominion Energy may need to seek to enforce a final U.S. court judgment in a foreign tribunal, which could involve a lengthy process.

Market performance and other changes may decrease the value of Dominion Energy's and Virginia Power's decommissioning trust funds and Dominion Energy's and Dominion Energy Gas' benefit plan assets or increase Dominion Energy's and Dominion Energy Gas' liabilities, which could then require significant additional funding. The performance of the capital markets affects the value of the assets that are held in trusts to satisfy future obligations to decommission Dominion Energy's and Virginia Power's nuclear plants and under Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans. The Companies have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuation and will yield uncertain returns, which may fall below expected return rates.

With respect to decommissioning trust funds, a decline in the market value of these assets may increase the funding requirements of the obligations to decommission Dominion Energy's and Virginia Power's nuclear plants or require additional NRC-approved funding assurance.

A decline in the market value of the assets held in trusts to satisfy future obligations under Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans may increase the funding requirements under such plans. Additionally, changes in interest rates will affect the liabilities under Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including increased numbers of retirements or changes in mortality assumptions, may also increase the funding requirements of the obligations related to the pension and other postretirement benefit plans.

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If the decommissioning trust funds and benefit plan assets are negatively impacted by market fluctuations or other factors, the Companies' results of operations, financial condition and/or cash flows could be negatively affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Companies use derivative instruments, including futures, swaps, forwards, options and FTRs, to manage commodity, currency and financial market risks. In addition, Dominion Energy and Dominion Energy Gas purchase and sell commodity-based contracts for hedging purposes.

The Dodd-Frank Act was enacted into law in July 2010 in an effort to improve regulation of financial markets. The Dodd-Frank Act includes provisions that will require certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end users, can choose to exempt their hedging transactions from these clearing and exchange trading requirements. Final rules for the over-the-counter derivative-related provisions of the Dodd-Frank Act will continue to be established through the ongoing rulemaking process of the applicable regulators, including rules regarding margin requirements for non-cleared swaps. If, as a result of changes to the rulemaking process, the Companies' derivative activities are not exempted from the clearing, exchange trading or margin requirements, the Companies could be subject to higher costs, including from higher margin requirements, for their derivative activities. In addition, changes to or the elimination of rulemaking that implements Title VII of the Dodd-Frank Act by the Companies' counterparties could result in increased costs related to the Companies' derivative activities.

Changing rating agency requirements could negatively affect the Companies' growth and business strategy. In order to maintain appropriate credit ratings to obtain needed credit at a reasonable cost in light of existing or future rating agency requirements, the Companies may find it necessary to take steps or change their business plans in ways that may adversely affect their growth and earnings. A reduction in the Companies' credit ratings could result in an increase in borrowing costs, loss of access to certain markets, or both, thus adversely affecting operating results and could require the Companies to post additional collateral in connection with some of its price risk management activities.

An inability to access financial markets could adversely affect the execution of the Companies' business plans. The Companies rely on access to short-term money markets and longer-term capital markets as significant sources of funding and liquidity for business plans with increasing capital expenditure needs, normal working capital and collateral requirements related to hedges of future sales and purchases of energy-related commodities. Deterioration in the Companies' creditworthiness, as evaluated by credit rating agencies or otherwise, or declines in market reputation either for the Companies or their industry in general, or general financial market disruptions outside of the Companies' control could increase their cost of borrowing or restrict their ability to access one or more financial markets. Further market disruptions could stem from delays in the current economic recovery, the bankruptcy of an unrelated company, general market disruption due to general credit market or political events, or the failure of financial institutions on which the Companies rely. Increased costs and restrictions on the Companies' ability to access financial markets may be severe enough to affect their ability to execute their business plans as scheduled.

Potential changes in accounting practices may adversely affect the Companies' financial results. The Companies cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry or their operations specifically. New accounting standards could be issued that could change the way they record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect earnings or could increase liabilities.

War, acts and threats of terrorism, intentional acts and other significant events could adversely affect the Companies' operations. The Companies cannot predict the impact that any future terrorist attacks may have on the energy industry in general, or on the Companies' business in particular. Any retaliatory military strikes or sustained military campaign may affect the Companies' operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets. In addition, the Companies' infrastructure facilities, including projects under construction, could be direct targets of, or indirect casualties of, an act of terror. For example, a physical attack on a critical substation in California resulted in serious impacts to the power grid. Furthermore, the physical compromise of the Companies' facilities could adversely affect the Companies' ability to manage these facilities effectively. Instability in financial markets as a result of terrorism, war, intentional acts, pandemic, credit crises, recession or other factors could result in a significant decline in the U.S. economy and increase the cost of insurance coverage. This could negatively impact the Companies' results of operations and financial condition.

Hostile cyber intrusions could severely impair the Companies' operations, lead to the disclosure of confidential information, damage the reputation of the Companies and otherwise have an adverse effect on the Companies' business. The Companies own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run the Companies' facilities are not completely isolated from external networks. There appears to be an increasing level of activity, sophistication and maturity of threat actors, in particular nation state actors, that wish to disrupt the U.S. bulk power system and the U.S. gas transmission or distribution system. Such parties could view the Companies' computer systems, software or networks as attractive targets for cyber attack. For example, malware has been designed to target software that runs the nation's critical infrastructure such as power transmission grids and gas pipelines. In addition, the Companies' businesses require that they and their vendors collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack on the systems that control the Companies' electric generation, electric or gas transmission or distribution assets could severely disrupt business operations, preventing the Companies from serving customers or collecting revenues. The breach of certain business systems could affect the Companies' ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to the Companies' reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. The Companies maintain property and casualty insurance that may cover certain damage caused by potential cyber incidents; however, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available. For these reasons, a significant cyber incident could materially and adversely affect the Companies' business, financial condition and results of operations.

Failure to attract and retain key executive officers and an appropriately qualified workforce could have an adverse effect on the Companies' operations. The Companies' business strategy is dependent on their ability to recruit, retain and motivate employees. The Companies' key executive officers are the CEO, CFO and presidents and those responsible for financial, operational, legal, regulatory and accounting functions. Competition for skilled management employees in these areas of the Companies' business operations is high. Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the length of time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the Companies' business. In addition, certain specialized knowledge is required of the Companies' technical employees for transmission, generation and distribution operations. The Companies' inability to attract and retain these employees could adversely affect their business and future operating results.

The completion of the merger with SCANA is subject to the receipt of consents, approvals and/or findings from governmental entities, which may impose conditions that could have an adverse effect on Dominion Energy or SCANA or could cause either Dominion Energy or SCANA to abandon the merger. The completion of the merger is also subject to there not having been substantive changes in certain South Carolina laws that have or would reasonably be expected to have an adverse effect on SCANA or its subsidiaries or orders of governmental entities or changes in law that impose any condition that would reasonably be expected to result in specified changes to the South Carolina Commission petition. Dominion Energy and SCANA are not required to complete the merger until after the applicable waiting period under the Hart-Scott-Rodino Act expires or terminates and the requisite authorizations, approvals, consents and/or permits are received from the FERC, NRC, South Carolina Commission, North Carolina Commission and Georgia Public Service Commission. Any of the relevant governmental entities may oppose the merger, fail to approve the merger, fail to make required findings in favor of the merger, or impose certain requirements or obligations as conditions for their consent, approval or findings or in connection with their review. Regulatory approvals of the merger or findings with respect to the merger may not be obtained on a timely basis or at all, and such approvals or findings may include conditions that could have an adverse effect on Dominion Energy and/or SCANA, or result in the abandonment of the merger. Dominion Energy cannot provide any assurance that Dominion Energy and SCANA will obtain the necessary approvals or findings or that any required conditions will not have an adverse effect on Dominion Energy following the merger.

Subject to the terms and conditions set forth in the merger agreement, the merger agreement may require Dominion Energy to accept conditions from regulators that could adversely impact Dominion Energy after the merger without either of Dominion Energy or SCANA having the right to refuse to close the merger on the basis of those regulatory conditions, except that Dominion Energy is generally not required, and SCANA is generally not permitted without Dominion Energy's prior approval, to take any action or accept any condition that results in a burdensome condition for Dominion Energy or SCANA as more fully described in the SCANA Merger Agreement.

In addition, the SCANA Merger Agreement provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if, since the date of the SCANA Merger Agreement, any governmental entity shall have enacted any order, or there shall have been any change in law (including the Base Load Review Act and the other laws governing South Carolina public utilities), which imposes any material change to the terms, conditions or undertakings set forth in the South Carolina Commission petition, or any significant changes to the economic value of the proposed terms set forth in the South Carolina Commission petition, in each case as determined by Dominion Energy in good faith.

The SCANA Merger Agreement further provides that Dominion Energy will have the right to refuse to close the merger if there shall have occurred any substantive change in the Base Load Review Act or other laws governing South Carolina public utilities which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries. There is currently pending before the South Carolina Senate a bill that would make substantive changes to the Base Load Review Act. This bill has passed the South Carolina House of Representatives. If this bill becomes law, Dominion Energy would not be obligated to complete the merger if it is determined that the bill has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries.

Certain lawsuits and regulatory actions have been filed against SCANA and SCE&G in connection with the abandonment of the V.C. Summer Units 2 and 3 new nuclear development project. If the relief requested in these matters (including a request for declaratory judgment that the Base Load Review Act is unconstitutional) is granted, Dominion Energy might not be obligated to complete the merger.

Dominion Energy and SCANA can provide no assurance that these risks will not materialize and either adversely impact Dominion Energy after the completion of the merger or, if such conditions rise to the thresholds discussed above, some of which,

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as described above, are in the subjective determination of Dominion Energy acting in good faith, or if the required authorizations, approvals, consents and/or permits are not obtained or received, result in the abandonment of the merger.

Dominion Energy expects to incur substantial expenses related to the merger with SCANA. Dominion Energy expects to incur relatively significant expenses in connection with completing the merger. While Dominion Energy has assumed that a certain level of transaction and integration expenses would be incurred, there are a number of factors beyond its control that could affect the total amount or the timing of its integration expenses. Many of the expenses that will be incurred, by their nature, are difficult to estimate accurately at the present time.

Following the merger with SCANA, Dominion Energy may be unable to successfully integrate SCANA's businesses. Dominion Energy and SCANA currently operate as independent public companies. After the merger, Dominion Energy will be required to devote significant management attention and resources to integrating SCANA's business. Potential difficulties Dominion Energy may encounter in the integration process include the following:

- The complexities associated with integrating SCANA and its utility businesses, while at the same time continuing to provide consistent, high quality services;
- The complexities of integrating a company with different core services, markets and customers;
- The inability to attract and retain key employees;
- Potential unknown liabilities and unforeseen increased expenses, delays or regulatory conditions associated with the merger;
- Difficulties in managing political and regulatory conditions related to SCANA's utility businesses after the merger;
- The cost recovery plan includes a moratorium on filing requests for adjustments in SCE&G's base electric rates until 2021 if the merger is approved by the South Carolina Commission, which would limit Dominion Energy's ability to recover increases in non-fuel related costs of electric operations for SCE&G's customers; and
- Performance shortfalls as a result of the diversion of Dominion Energy management's attention caused by completing the merger and integrating SCANA's utility businesses.

For these reasons, it is possible that the integration process following the merger could result in the distraction of Dominion Energy's management, the disruption of Dominion Energy's ongoing business or inconsistencies in its services, standards, controls, procedures and policies, any of which could adversely affect the ability of Dominion Energy to maintain or establish relationships with current and prospective customers, vendors and employees or could otherwise adversely affect the business and financial results of Dominion Energy.

Dominion Energy and SCANA may be materially adversely affected by negative publicity related to the merger and in connection with other related matters, including the abandonment of the V.C. Summer Units 2 and 3 new nuclear development project. From time to time, political and public sentiment in connection with the merger and in connection with other matters, including the abandonment of the V.C. Summer Units 2 and 3 new nuclear development project may result in a significant amount of adverse press coverage and other adverse public statements affecting Dominion Energy and SCANA. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceedings, as well as responding to and addressing adverse press coverage and other adverse public statements, can divert the time and effort of senior management from the management of Dominion Energy's and SCANA's respective businesses.

Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of Dominion Energy and SCANA, on the morale and performance of their employees and on their relationships with their respective regulators, customers and commercial counterparties. It may also have a negative impact on their ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on Dominion Energy's and SCANA's respective business, financial condition, results of operations and prospects.

The market value of Dominion Energy common stock could decline if large amounts of its common stock are sold following the merger with SCANA. Following the merger, shareholders of Dominion Energy and former SCANA shareholders will own interests in a combined company operating an expanded business with more assets and a different mix of liabilities. Current shareholders of Dominion Energy and SCANA may not wish to continue to invest in the combined company, or may wish to reduce their investment in the combined company, in order to comply with institutional investing guidelines, to increase diversification or to track any rebalancing of stock indices in which Dominion Energy common stock or SCANA common stock is or was included. If, following the merger, large amounts of Dominion Energy common stock are sold, the price of its common stock could decline.

The merger with SCANA may not be accretive to operating earnings and may cause dilution to Dominion Energy's earnings per share, which may negatively affect the market price of Dominion Energy common stock. Dominion Energy currently anticipates that the merger will be immediately accretive to Dominion Energy's forecasted operating earnings per share on a standalone basis. This expectation is based on preliminary estimates, which may materially change. Dominion Energy may encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates or its ability to realize operational efficiencies. Any of these factors could cause a decrease in Dominion Energy's operating earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Dominion Energy's common stock. Dominion Energy expects the initial effect of the merger on its GAAP earnings will be a decrease in such earnings due to the anticipated charges for refunds to SCE&G customers, write-offs of regulatory assets and transaction costs.

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Litigation against SCANA and Dominion Energy could result in an injunction preventing the completion of the merger with SCANA or may adversely affect the combined company's business, financial condition or results of operations following the merger with SCANA. Following the announcement of the SCANA Merger Agreement, lawsuits have been filed asserting claims relating to the merger. Among other things, the lawsuits allege breaches of various fiduciary duties by the members of the SCANA board in connection with the merger and allegations that Dominion Energy and/or SCANA aided and abetted such alleged breaches. Among other remedies, the plaintiffs seek to enjoin the merger, rescind the merger agreement or be awarded monetary damages should the merger be completed. While Dominion Energy believes that dismissal of these lawsuits is warranted, the outcome of any such litigation is inherently uncertain. The defense or settlement of any lawsuit or any claim that remains unresolved at the time the merger closes may adversely affect the combined company's business, financial condition or results of operation. Additionally, other lawsuits may be filed in the future making similar or new claims and seeking similar or new remedies.

Dominion Energy has goodwill and other intangible assets on its balance sheet, and these amounts will increase as a result of the merger with SCANA. If its goodwill or other intangible assets become impaired in the future, Dominion Energy may be required to record a significant, non-cash charge to earnings and reduce its shareholders' equity. Upon the completion of the merger, Dominion Energy will record as goodwill the excess of the purchase price paid by Dominion Energy over the fair value of SCANA's assets and liabilities as determined for financial accounting purposes. Under GAAP, intangible assets are reviewed for impairment on an annual basis or more frequently whenever events or circumstances indicate that its carrying value may not be recoverable. If Dominion Energy's intangible assets, including goodwill as a result of the merger, are determined to be impaired in the future, Dominion Energy may be required to record a significant, non-cash charge to earnings during the period in which the impairment is determined.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

As of December 31, 2017, Dominion Energy owned its principal executive office and three other corporate offices, all located in Richmond, Virginia. Dominion Energy also leases corporate offices in other cities in which its subsidiaries operate. Virginia Power and Dominion Energy Gas share Dominion Energy's principal office in Richmond, Virginia, which is owned by Dominion Energy. In addition, Virginia Power's Power Delivery and Power Generation segments share certain leased buildings and equipment. See Item 1. Business for additional information about each segment's principal properties, which information is incorporated herein by reference.

Dominion Energy's assets consist primarily of its investments in its subsidiaries, the principal properties of which are described here and in Item 1. Business.

Certain of Virginia Power's property is subject to the lien of the Indenture of Mortgage securing its First and Refunding Mortgage Bonds. There were no bonds outstanding as of December 31, 2017; however, by leaving the indenture open, Virginia Power expects to retain the flexibility to issue mortgage bonds in the future. Certain of Dominion Energy's merchant generation facilities are also subject to liens.

GAS INFRASTRUCTURE

Dominion Energy and Dominion Energy Gas

East Ohio's gas distribution network is located in Ohio. This network involves approximately 18,900 miles of pipe, exclusive of service lines. The right-of-way grants for many natural gas pipelines have been obtained from the actual owners of real estate, as underlying titles have been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many natural gas pipelines are on publicly-owned property, where company rights and actions are determined on a case-by-case basis, with results that range from reimbursed relocation to revocation of permission to operate.

Dominion Energy Gas has approximately 10,400 miles, excluding interests held by others, of gas transmission, gathering and storage pipelines located in the states of Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. Dominion Energy Gas also owns NGL processing plants capable of processing over 270,000 mcf per day of natural gas. Hastings is the largest plant and is capable of processing over 180,000 mcf per day of natural gas. Hastings can also fractionate over 580,000 Gals per day of NGLs into marketable products, including propane, isobutane, butane and natural gasoline. NGL operations have storage capacity of 1,226,500 Gals of propane, 109,000 Gals of isobutane, 442,000 Gals of butane, 2,000,000 Gals of natural gasoline and 1,012,500 Gals of mixed NGLs. Dominion Energy Gas also operates 20 underground gas storage fields located in New York, Ohio, Pennsylvania and West Virginia, with approximately 2,000 storage wells and approximately 399,000 acres of operated leaseholds.

The total designed capacity of the underground storage fields operated by Dominion Energy Gas is approximately 926 bcf. Certain storage fields are jointly-owned and operated by Dominion Energy Gas. The capacity of those fields owned by Dominion Energy Gas' partners totals approximately 223 bcf.

Dominion Energy

Cove Point's LNG facility has an operational peak regasification daily send-out capacity of approximately 1.8 million Dths and an aggregate LNG storage capacity of approximately 14.6 bcfe. In addition, Cove Point has a liquefier that has the potential to create approximately 15,000 Dths/day.

The Cove Point pipeline is a 36-inch diameter underground, interstate natural gas pipeline that extends approximately 88 miles from Cove Point to interconnections with Transcontinental Gas Pipe Line Company, LLC in Fairfax County, Virginia, and with Columbia Gas Transmission, LLC and DETI in Loudoun County, Virginia. In 2009, the original pipeline was expanded to include a 36-inch diameter expansion that extends approximately 48 miles, roughly 75% of which is parallel to the original pipeline.

Questar Gas distributes gas to customers in Utah, Wyoming and Idaho. Questar Gas owns and operates distribution systems and has a total of 29,600 miles of street mains, service lines and interconnecting pipelines. Questar Gas has a major operations center in Salt Lake City, and has operations centers, field offices and service-center facilities in other parts of its service area.

Dominion Energy Questar Pipeline operates 2,200 miles of natural gas transportation pipelines that interconnect with other pipelines in Utah, Wyoming and western Colorado. Dominion Energy Questar Pipeline's system ranges in diameter from lines that are less than four inches to 36-inches. Dominion Energy Questar Pipeline owns the Clay Basin storage facility in northeastern Utah, which has a certificated capacity of 120 bcf, including 54 bcf of working gas.

DECG's interstate natural gas pipeline system in South Carolina and southeastern Georgia is comprised of nearly 1,500 miles of transmission pipeline.

Hope's gas distribution network located in West Virginia is comprised of 3,200 miles of pipe, exclusive of service lines.

In total, Dominion Energy has 171 compressor stations with approximately 1,190,000 installed compressor horsepower.

POWER DELIVERY

See Item 1. Business, *General* for details regarding Power Delivery's principal properties, which primarily include transmission and distribution lines.

POWER GENERATION

Dominion Energy and Virginia Power generate electricity for sale on a wholesale and a retail level. Dominion Energy and Virginia Power supply electricity demand either from their generation facilities or through purchased power contracts. As of December 31, 2017, Power Generation's total utility and merchant generating capacity was approximately 26,000 MW. The following tables list Power Generation's utility and merchant generating units and capability, as of December 31, 2017.

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VIRGINIA POWER UTILITY GENERATION(1)

Plant	Location	Net Summer Capability (MW)	Percentage Net Summer Capability
Gas			
Brunswick County (CC)	Brunswick County, VA	1,376	
Warren County (CC)	Warren County, VA	1,350	
Ladysmith (CT)	Ladysmith, VA	784	
Bear Garden (CC)	Buckingham County, VA	622	
Remington (CT)	Remington, VA	608	
Possum Point (CC)	Dumfries, VA	573	
Chesterfield (CC)	Chester, VA	397	
Elizabeth River (CT)	Chesapeake, VA	348	
Possum Point(6)	Dumfries, VA	316	
Bellemeade (CC)(6)	Richmond, VA	267	
Bremo(6)	Bremo Bluff, VA	227	
Gordonsville Energy (CC)	Gordonsville, VA	218	
Gravel Neck (CT)	Surry, VA	170	
Darbytown (CT)	Richmond, VA	168	
Rosemary (CC)	Roanoke Rapids, NC	165	
Total Gas		7,589	37%
Coal			
Mt. Storm	Mt. Storm, WV	1,624	
Chesterfield(6)	Chester, VA	1,268	
Virginia City Hybrid Energy Center	Wise County, VA	610	
Clover	Clover, VA	439(2)	
Yorktown(3)	Yorktown, VA	323	
Mecklenburg(6)	Clarksville, VA	138	
Total Coal		4,402	21
Nuclear			
Surry	Surry, VA	1,676	
North Anna	Mineral, VA	1,672(4)	
Total Nuclear		3,348	16
Oil			
Yorktown	Yorktown, VA	790	
Possum Point	Dumfries, VA	783	
Gravel Neck (CT)	Surry, VA	198	
Darbytown (CT)	Richmond, VA	168	
Possum Point (CT)	Dumfries, VA	72	
Chesapeake (CT)	Chesapeake, VA	51	
Low Moor (CT)	Covington, VA	48	
Northern Neck (CT)	Lively, VA	47	
Total Oil		2,157	11
Hydro			
Bath County	Warm Springs, VA	1,808(5)	
Gaston	Roanoke Rapids, NC	220	
Roanoke Rapids	Roanoke Rapids, NC	95	
Other	Various	3	
Total Hydro		2,126	10
Biomass			
Pittsylvania	Hurt, VA	83	
Altavista	Altavista, VA	51	
Polyester	Hopewell, VA	51	
Southampton	Southampton, VA	51	
Total Biomass		236	1
Solar			
Whitehouse Solar	Louisa County, VA	20	
Woodland Solar	Isle of Wight County, VA	19	
Scott Solar	Powhatan County, VA	17	
Total Solar		56	—
Various			
Mt. Storm (CT)	Mt. Storm, WV	11	—
		19,925	
Power Purchase Agreements		854	4
Total Utility Generation		20,779	100%

Note: (CT) denotes combustion turbine and (CC) denotes combined cycle.

(1) The table excludes Virginia Power's Morgans Corner solar facility located in Pasquotank County, NC, Remington solar facility located in Remington, VA and Oceana solar facility located in Virginia Beach, VA which have a net summer capacity of 20 MW, 20 MW and 18 MW, respectively as these facilities are dedicated to serving non-jurisdictional customers.

(2) Excludes 50% undivided interest owned by ODEC.

(3) Coal-fired units are expected to be retired at Yorktown power station as early as 2018 as a result of the issuance of MATS.

(4) Excludes 11.6% undivided interest owned by ODEC.

(5) Excludes 40% undivided interest owned by Allegheny Generating Company, a subsidiary of FirstEnergy Corp.

(6) In January 2018, Virginia Power announced it would place certain units at this facility in cold storage.

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Dominion Merchant Generation

Plant	Location	Net Summer Capability (MW)	Percentage Net Summer Capability
Nuclear			
Millstone	Waterford, CT	2,001(1)	
Total Nuclear		2,001	39%
Gas			
Fairless (CC)	Fairless Hills, PA	1,240	
Manchester (CC)	Providence, RI	468	
Total Gas		1,708	33
Solar(2)			
Escalante I, II and III	Beaver County, UT	120(3)	
Amazon Solar Farm Virginia—Southampton	Newsoms, VA	100	
Amazon Solar Farm Virginia—Accomack	Oak Hall, VA	80	
Innovative Solar 37	Morven, NC	79	
Moffett Solar 1	Ridgeland, SC	71	
Granite Mountain East and West	Iron County, UT	65(3)	
Summit Farms Solar	Moyock, NC	60	
Enterprise	Iron County, UT	40(3)	
Iron Springs	Iron County, UT	40(3)	
Pavant Solar	Holden, UT	34(4)	
Camelot Solar	Mojave, CA	30(4)	
Midway II	Calipatria, CA	30	
Indy I, II and III	Indianapolis, IN	20(4)	
Amazon Solar Farm Virginia—Buckingham	Cumberland, VA	20	
Amazon Solar Farm Virginia—Correctional	Barhamsville, VA	20	
Hecate Cherrydale	Cape Charles, VA	20	
Amazon Solar Farm Virginia—Sappony	Soney Creek, VA	20	
Amazon Solar Farm Virginia—Scott II	Powhatan, VA	20	
Cottonwood Solar	Kings and Kern counties, CA	16(4)	
Alamo Solar	San Bernardino, CA	13(4)	
Maricopa West Solar	Kern County, CA	13(4)	
Imperial Valley Solar	Imperial, CA	13(4)	
Richland Solar	Jeffersonville, GA	13(4)	
CID Solar	Corcoran, CA	13(4)	
Kansas Solar	Lenmore, CA	13(4)	
Kent South Solar	Lenmore, CA	13(4)	
Old River One Solar	Bakersfield, CA	13(4)	
West Antelope Solar	Lancaster, CA	13(4)	
Adams East Solar	Tranquility, CA	13(4)	
Catalina 2 Solar	Kern County, CA	12(4)	
Mulberry Solar	Selmer, TN	11(4)	
Selmer Solar	Selmer, TN	11(4)	
Columbia 2 Solar	Mojave, CA	10(4)	
Hecate Energy Clarke County	White Post, VA	10	
Ridgeland Solar Farm I	Ridgeland, SC	10	
Azalea Solar	Davisboro, GA	5(4)	
Clipperton	Clinton, NC	5	
Fremont Solar	Fremont, NC	5	
Moorings 2	Lagrange, NC	5	
Pikeville Solar	Pikeville, NC	5	
Wakefield	Zebulon, NC	5	
Somers Solar	Somers, CT	3(4)	
Total Solar		1,112	22
Wind			
Fowler Ridge(5)	Benton County, IN	150(6)	
NedPower(5)	Grant County, WV	132(7)	
Total Wind		282	6
Fuel Cell			
Bridgeport Fuel Cell	Bridgeport, CT	15	
Total Fuel Cell		15	—
Total Merchant Generation		5,118	100%

Note: (CC) denotes combined cycle.
(1) Excludes 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal and Green Mountain.
(2) All solar facilities are alternating current.
(3) Excludes 50% noncontrolling interest owned by NRG. Dominion Energy's interest is subject to a lien securing Dominion Solar Projects III, Inc.'s debt.
(4) Excludes 33% noncontrolling interest owned by Terra Nova Renewable Partners. Dominion Energy's interest is subject to a lien securing SBL Holdco's debt.
(5) Subject to a lien securing the facility's debt.
(6) Excludes 50% membership interest owned by BP.
(7) Excludes 50% membership interest owned by Shell.

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Item 3. Legal Proceedings

From time to time, the Companies are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by the Companies, or permits issued by various local, state and/or federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, the Companies and their subsidiaries are involved in various legal proceedings.

In January 2016, Virginia Power self-reported a release of mineral oil from the Crystal City substation and began extensive cleanup. Virginia Power assumed the role of responsible party and has continued to cooperate with ongoing requirements for investigative and corrective action. In December 2016, the Virginia State Water Control Board approved a consent order between the VDEQ and Virginia Power related to this matter, which included a penalty in excess of $100,000. In May 2017, the VDEQ formally terminated the consent order, finding that all requirements had been completed. Also in May 2017, the U.S. Department of the Interior, on behalf of several federal and state agencies, proposed a settlement to resolve the agencies' claims for natural resource damages related to the mineral oil release. In January 2018, Virginia Power and the natural resource trustee agencies executed a settlement agreement that would require Virginia Power to pay approximately $400,000 to fund wetland restoration and related projects in the location of the release. Final approval of the settlement is pending completion of a 30-day public comment period which is expected during the first quarter of 2018.

See Notes 13 and 22 to the Consolidated Financial Statements and *Future Issues and Other Matters* in Item 7. MD&A, which information is incorporated herein by reference, for discussion of various environmental and other regulatory proceedings to which the Companies are a party.

Item 4. Mine Safety Disclosures

Not applicable.

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Information concerning the executive officers of Dominion Energy, each of whom is elected annually, is as follows:

Name and Age	Business Experience Past Five Years(1)
Thomas F. Farrell, II (63)	Chairman of the Board of Directors, President and CEO of Dominion Energy from April 2007 to date; Chairman and CEO of Dominion Energy Midstream GP, LLC (the general partner of Dominion Energy Midstream) from March 2014 to date and President from February 2015 to date; CEO of Dominion Energy Gas from September 2013 to date and Chairman from March 2014 to date; Chairman and CEO of Virginia Power from February 2006 to date and Questar Gas from September 2016 to date.
Mark F. McGettrick (60)	Executive Vice President and CFO of Dominion Energy from June 2009 to date, Dominion Energy Midstream GP, LLC from March 2014 to date, Virginia Power from June 2009 to date, Dominion Energy Gas from September 2013 to date, and Questar Gas from September 2016 to date.
Robert M. Blue (50)	Executive Vice President and President & CEO—Power Delivery Group of Dominion Energy from May 2017 to date; President and COO—Power Delivery Group of Virginia Power from May 2017 to date; Senior Vice President and President & CEO—Dominion Virginia Power of Dominion Energy from January 2017 to May 2017; President and COO of Virginia Power from January 2017 to May 2017; Senior Vice President—Law, Regulation & Policy of Dominion Energy, Dominion Energy Gas and Dominion Energy Midstream GP, LLC from February 2016 to December 2016 and Questar Gas from September 2016 to December 2016; President of Virginia Power from January 2016 to December 2016; Senior Vice President—Regulation, Law, Energy Solutions and Policy of Dominion Energy and Dominion Energy Gas from May 2015 to January 2016 and Dominion Energy Midstream GP, LLC from July 2015 to January 2016; Senior Vice President—Regulation, Law, Energy Solutions and Policy of Virginia Power from May 2015 to December 2015; President of Virginia Power from January 2014 to May 2015; Senior Vice President—Law, Public Policy and Environment of Dominion Energy from January 2011 to December 2013.
Paul D. Koonce (58)	Executive Vice President and President & CEO—Power Generation Group of Dominion Energy from January 2017 to date; President and COO—Power Generation Group of Virginia Power from May 2017 to date; Executive Vice President and CEO—Dominion Generation Group of Dominion Energy from January 2016 to December 2016; Executive Vice President and CEO—Energy Infrastructure Group of Dominion Energy from February 2013 to December 2015; Executive Vice President of Dominion Energy from April 2006 to February 2013; Executive Vice President of Dominion Energy Midstream GP, LLC from March 2014 to December 2015; President and COO of Virginia Power from June 2009 to May 2017; President of Dominion Energy Gas from September 2013 to December 2015.
Diane Leopold (51)	Executive Vice President and President & CEO—Gas Infrastructure Group of Dominion Energy and Dominion Energy Midstream GP, LLC from May 2017 to date; President of Dominion Energy Gas from January 2017 to date and Questar Gas from August 2017 to date; Senior Vice President and President & CEO—Dominion Energy of Dominion Energy and Dominion Energy Midstream GP, LLC from January 2017 to May 2017; President of DETI, East Ohio and Dominion Cove Point, Inc. from January 2014 to date; Senior Vice President of DETI from April 2012 to December 2013.
Mark O. Webb (53)	Senior Vice President—Corporate Affairs and Chief Legal Officer of Dominion Energy, Virginia Power, Dominion Energy Gas, Dominion Energy Midstream GP, LLC, and Questar Gas from January 2017 to date; Senior Vice President, General Counsel and Chief Risk Officer of Dominion Energy, Virginia Power and Dominion Energy Gas from May 2016 to December 2016; Senior Vice President and General Counsel of Dominion Energy Midstream GP, LLC from May 2016 to December 2016 and Questar Gas from September 2016 to December 2016; Vice President, General Counsel and Chief Risk Officer of Dominion Energy, Virginia Power and Dominion Energy Gas from January 2014 to May 2016; Vice President and General Counsel of Dominion Energy Midstream GP, LLC from March 2014 to May 2016; Vice President and General Counsel of Dominion Energy and Virginia Power from January 2013 to December 2013 and Dominion Energy Gas from September 2013 to December 2013.
Michele L. Cardiff (50)	Vice President, Controller and CAO of Dominion Energy and Virginia Power from April 2014 to date, Dominion Energy Gas and Dominion Energy Midstream GP, LLC from March 2014 to date and Questar Gas from September 2016 to date; Vice President—Accounting of DES from January 2014 to March 2014; Vice President and General Auditor of DES from September 2012 to December 2013.

(1) Any service listed for Virginia Power, Dominion Energy Midstream GP, LLC, Dominion Energy Gas, DETI, East Ohio, Dominion Cove Point, Inc., Questar Gas and DES reflects service at a subsidiary of Dominion Energy.

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Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Dominion Energy

Dominion Energy’s common stock is listed on the NYSE. At February 15, 2018, there were approximately 123,000 record holders of Dominion Energy’s common stock. The number of record holders is comprised of individual shareholder accounts maintained on Dominion Energy’s transfer agent records and includes accounts with shares held in (1) certificate form, (2) book-entry in the Direct Registration System and (3) book-entry under Dominion Energy Direct®. Discussions of expected dividend payments and restrictions on Dominion Energy’s payment of dividends required by this Item are contained in *Liquidity and Capital Resources* in Item 7. MD&A and Notes 17 and 20 to the Consolidated Financial Statements. Cash dividends were paid quarterly in 2017 and 2016. Quarterly information concerning stock prices and dividends is disclosed in Note 26 to the Consolidated Financial Statements, which information is incorporated herein by reference.

The following table presents certain information with respect to Dominion Energy’s common stock repurchases during the fourth quarter of 2017:

DOMINION ENERGY PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share(2)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased under the Plans or Programs(3)
10/1/2017-10/31/17	**29,305**	**$76.93**	**N/A**	**19,629,059 shares/$1.18 billion**
11/1/2017-11/30/17	**8**	**80.49**	**N/A**	**19,629,059 shares/$1.18 billion**
12/1/2017-12/31/17	**4**	**83.57**	**N/A**	**19,629,059 shares/$1.18 billion**
Total	**29,317**	**$76.93**	**N/A**	**19,629,059 shares/$1.18 billion**

(1) 29,305, 8 and 4 shares were tendered by employees to satisfy tax withholding obligations on vested restricted stock in October, November and December 2017, respectively.
(2) Represents the weighted-average price paid per share.
(3) The remaining repurchase authorization is pursuant to repurchase authority granted by the Dominion Energy Board of Directors in February 2005, as modified in June 2007. The aggregate authorization granted by the Dominion Energy Board of Directors was 86 million shares (as adjusted to reflect a two-for-one stock split distributed in November 2007) not to exceed $4 billion.

Virginia Power

There is no established public trading market for Virginia Power’s common stock, all of which is owned by Dominion Energy. Potential restrictions on Virginia Power’s payment of dividends are discussed in Note 20 to the Consolidated Financial Statements. In 2016, no dividends were declared or paid given the sufficiency of operating and other cash flows at Dominion Energy. In 2017, Virginia Power declared and paid quarterly cash dividends of $445 million, $409 million and $345 million during the first three quarters of 2017, respectively. Virginia Power intends to pay quarterly cash dividends in 2018 but is neither required to nor restricted, except as described above, from making such payments.

Dominion Energy Gas

All of Dominion Energy Gas’ membership interests are owned by Dominion Energy. Potential restrictions on Dominion Energy Gas’ payment of distributions are discussed in Note 20 to the Consolidated Financial Statements. Dominion Energy Gas declared and paid cash distributions of $150 million in the second quarter of 2016. Dominion Energy Gas declared and paid cash distributions of $7 million and $8 million in the first and second quarters of 2017, respectively. Dominion Energy Gas intends to pay quarterly cash dividends in 2018 but is neither required to nor restricted, except as described above, from making such payments.

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Item 6. Selected Financial Data

The following table should be read in conjunction with the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

DOMINION ENERGY

Year Ended December 31,	2017(1)	2016(2)	2015	2014(3)	2013(4)
(millions, except per share amounts)					
Operating revenue	**$12,586**	$11,737	$11,683	$12,436	$13,120
Income from continuing operations, net of tax(5)	**2,999**	2,123	1,899	1,310	1,789
Loss from discontinued operations, net of tax(5)	**—**	—	—	—	(92)
Net income attributable to Dominion Energy	**2,999**	2,123	1,899	1,310	1,697
Income from continuing operations before loss from discontinued operations per common share-basic	**4.72**	3.44	3.21	2.25	3.09
Net income attributable to Dominion Energy per common share-basic	**4.72**	3.44	3.21	2.25	2.93
Income from continuing operations before loss from discontinued operations per common share-diluted	**4.72**	3.44	3.20	2.24	3.09
Net income attributable to Dominion Energy per common share-diluted	**4.72**	3.44	3.20	2.24	2.93
Dividends declared per common share	**3.035**	2.80	2.59	2.40	2.25
Total assets	**76,585**	71,610	58,648	54,186	49,963
Long-term debt	**30,948**	30,231	23,468	21,665	19,199

(1) Includes $851 million of tax benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate, partially offset by $96 million of after-tax charges associated with equity method investments in wind-powered generation facilities.

(2) Includes a $122 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

(3) Includes $248 million of after-tax charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, a $193 million after-tax charge related to Dominion Energy's restructuring of its producer services business and a $174 million after-tax charge associated with the Liability Management Exercise.

(4) Includes a $109 million after-tax charge related to Dominion Energy's restructuring of its producer services business ($76 million) and an impairment of certain natural gas infrastructure assets ($33 million). Also in 2013, Dominion Energy recorded a $92 million after-tax net loss from the discontinued operations of Brayton Point and Kincaid.

(5) Amounts attributable to Dominion Energy's common shareholders.

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

MD&A discusses Dominion Energy's results of operations and general financial condition and Virginia Power's and Dominion Energy Gas' results of operations. MD&A should be read in conjunction with Item 1. Business and the Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. Virginia Power and Dominion Energy Gas meet the conditions to file under the reduced disclosure format, and therefore have omitted certain sections of MD&A.

CONTENTS OF MD&A

MD&A consists of the following information:

- Forward-Looking Statements
- Accounting Matters—Dominion Energy
- Dominion Energy
  - Results of Operations
  - Segment Results of Operations
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FORWARD-LOOKING STATEMENTS

This report contains statements concerning the Companies' expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may," "continue," "target" or other similar words.

The Companies make forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to differ materially from predicted results. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Additionally, other factors may cause actual results to differ materially from those indicated in any forward-looking statement. These factors include but are not limited to:

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events and other natural disasters, including, but not limited to, hurricanes, high winds, severe storms, earthquakes, flooding and changes in water temperatures and availability that can cause outages and property damage to facilities;
- Federal, state and local legislative and regulatory developments, including changes in federal and state tax laws and regulations, including provisions of the 2017 Tax Reform Act that take effect beginning in 2018;
- Changes to federal, state and local environmental laws and regulations, including those related to climate change, the tightening of emission or discharge limits for GHGs and other substances, more extensive permitting requirements and the regulation of additional substances;
- Cost of environmental compliance, including those costs related to climate change;
- Changes in implementation and enforcement practices of regulators relating to environmental standards and litigation exposure for remedial activities;
- Difficulty in anticipating mitigation requirements associated with environmental and other regulatory approvals or related appeals;
- Risks associated with the operation of nuclear facilities, including costs associated with the disposal of spent nuclear fuel, decommissioning, plant maintenance and changes in existing regulations governing such facilities;
- Unplanned outages at facilities in which the Companies have an ownership interest;
- Fluctuations in energy-related commodity prices and the effect these could have on Dominion Energy's and Dominion Energy Gas' earnings and the Companies' liquidity position and the underlying value of their assets;
- Counterparty credit and performance risk;
- Global capital market conditions, including the availability of credit and the ability to obtain financing on reasonable terms;
- Risks associated with Virginia Power's membership and participation in PJM, including risks related to obligations created by the default of other participants;
- Fluctuations in the value of investments held in nuclear decommissioning trusts by Dominion Energy and Virginia Power and in benefit plan trusts by Dominion Energy and Dominion Energy Gas;
- Fluctuations in interest rates or foreign currency exchange rates;
- Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- Risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Impacts of acquisitions, divestitures, transfers of assets to joint ventures or Dominion Energy Midstream, and retirements of assets based on asset portfolio reviews;
- The expected timing and likelihood of completion of the proposed acquisition of SCANA, including the ability to obtain the requisite approvals of SCANA's shareholders and the terms and condition of any regulatory approvals;
- Receipt of approvals for, and timing of, closing dates for other acquisitions and divestitures;
- The timing and execution of Dominion Energy Midstream's growth strategy;
- Changes in rules for regional transmission organizations and independent system operators in which Dominion Energy and Virginia Power participate, including changes in rate designs, changes in FERC's interpretation of market rules and new and evolving capacity models;
- Political and economic conditions, including inflation and deflation;
- Domestic terrorism and other threats to the Companies' physical and intangible assets, as well as threats to cybersecurity;

- Changes in demand for the Companies' services, including industrial, commercial and residential growth or decline in the Companies' service areas, changes in supplies of natural gas delivered to Dominion Energy and Dominion Energy Gas' pipeline and processing systems, failure to maintain or replace customer contracts on favorable terms, changes in customer growth or usage patterns, including as a result of energy conservation programs, the availability of energy efficient devices and the use of distributed generation methods;
- Additional competition in industries in which the Companies operate, including in electric markets in which Dominion Energy's merchant generation facilities operate and potential competition from the development and deployment of alternative energy sources, such as self-generation and distributed generation technologies, and availability of market alternatives to large commercial and industrial customers;
- Competition in the development, construction and ownership of certain electric transmission facilities in Virginia Power's service territory in connection with FERC Order 1000;
- Changes in technology, particularly with respect to new, developing or alternative sources of generation and smart grid technologies;
- Changes to regulated electric rates collected by Virginia Power and regulated gas distribution, transportation and storage rates, including LNG storage, collected by Dominion Energy and Dominion Energy Gas;
- Changes in operating, maintenance and construction costs;
- Timing and receipt of regulatory approvals necessary for planned construction or growth projects and compliance with conditions associated with such regulatory approvals;
- The inability to complete planned construction, conversion or growth projects at all, or with the outcomes or within the terms and time frames initially anticipated, including as a result of increased public involvement or intervention in such projects;
- Adverse outcomes in litigation matters or regulatory proceedings; and
- The impact of operational hazards, including adverse developments with respect to pipeline and plant safety or integrity, equipment loss, malfunction or failure, operator error, and other catastrophic events.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors.

The Companies' forward-looking statements are based on beliefs and assumptions using information available at the time the statements are made. The Companies caution the reader not to place undue reliance on their forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. The Companies undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

ACCOUNTING MATTERS

Critical Accounting Policies and Estimates

Dominion Energy has identified the following accounting policies, including certain inherent estimates, that as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to its financial condition or results of operations under different conditions or using different assumptions. Dominion Energy has discussed the development, selection and disclosure of each of these policies with the Audit Committee of its Board of Directors.

ACCOUNTING FOR REGULATED OPERATIONS

The accounting for Dominion Energy's regulated electric and gas operations differs from the accounting for nonregulated operations in that Dominion Energy is required to reflect the effect of rate regulation in its Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator.

Dominion Energy evaluates whether or not recovery of its regulatory assets through future rates is probable and makes various assumptions in its analysis. The expectations of future recovery are generally based on orders issued by regulatory commissions, legislation or historical experience, as well as discussions with applicable regulatory authorities and legal counsel. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. See Notes 12 and 13 to the Consolidated Financial Statements for additional information.

ASSET RETIREMENT OBLIGATIONS

Dominion Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists and the ARO can be reasonably estimated. These AROs are recognized at fair value as incurred or when sufficient information becomes available to determine fair value and are generally capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Dominion Energy estimates the fair value of its AROs using present value techniques, in which it makes various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. The impact on measurements of new AROs or remeasurements of existing AROs, using different cost escalation or credit-adjusted risk free rates in the future, may be significant. When Dominion Energy revises any assumptions used to calculate the fair value of existing AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset for assets that are in service; for assets that have ceased operations, Dominion Energy adjusts the carrying amount of the ARO liability with such changes recognized in income. Dominion Energy accretes the ARO liability to reflect the passage of time.

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In 2017, 2016 and 2015, Dominion Energy recognized $117 million, $104 million and $93 million, respectively, of accretion, and expects to recognize $117 million in 2018. Dominion Energy records accretion and depreciation associated with utility nuclear decommissioning AROs and regulated pipeline replacement AROs as an adjustment to the regulatory liabilities related to these items.

A significant portion of Dominion Energy's AROs relates to the future decommissioning of its merchant and utility nuclear facilities. These nuclear decommissioning AROs are reported in the Power Generation segment. At December 31, 2017, Dominion Energy's nuclear decommissioning AROs totaled $1.5 billion, representing approximately 62% of its total AROs. Based on their significance, the following discussion of critical assumptions inherent in determining the fair value of AROs relates to those associated with Dominion Energy's nuclear decommissioning obligations.

Dominion Energy obtains from third-party specialists periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for its nuclear plants. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. In addition, Dominion Energy's cost estimates include cost escalation rates that are applied to the base year costs. Dominion Energy determines cost escalation rates, which represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities, for each nuclear facility. The selection of these cost escalation rates is dependent on subjective factors which are considered to be critical assumptions.

INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws, including the provisions of the 2017 Tax Reform Act, involves uncertainty, since tax authorities may interpret the laws differently. In addition, the states in which we operate may or may not conform to some or all the provisions in the 2017 Tax Reform Act. Ultimate resolution or clarification of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

Given the uncertainty and judgment involved in the determination and filing of income taxes, there are standards for recognition and measurement in financial statements of positions taken or expected to be taken by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. At December 31, 2017, Dominion Energy had $38 million of unrecognized tax benefits. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations.

Deferred income tax assets and liabilities are recorded representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Dominion Energy evaluates quarterly the probability of realizing deferred tax assets by considering current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets. Dominion Energy establishes a valuation allowance when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. At December 31, 2017, Dominion Energy had established $146 million of valuation allowances.

The 2017 Tax Reform Act includes a broad range of tax reform provisions affecting the Companies, including changes in corporate tax rates and business deductions. Many of these provisions differ significantly from prior U.S. tax law, resulting in pervasive financial reporting implications for the Companies. The 2017 Tax Reform Act includes significant changes to the Internal Revenue Code of 1986, including amendments which significantly change the taxation of individuals and business entities and includes specific provisions related to regulated public utilities including Dominion Energy subsidiaries Questar Gas, Wexpro, Hope, Virginia Power, and Dominion Energy Gas' subsidiaries DETI and East Ohio. The more significant changes that impact the Companies included in the 2017 Tax Reform Act are (i) reducing the corporate federal income tax rate from 35% to 21%; (ii) limiting the deductibility of interest expense to 30% of adjusted taxable income for certain businesses; (iii) permitting 100% expensing (100% bonus depreciation) for certain qualified property; (iv) eliminating the deduction for qualified domestic production activities; and (v) limiting the utilization of net operating losses arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward. The specific provisions related to regulated public utilities in the 2017 Tax Reform Act generally allow for the continued deductibility of interest expense, the exclusion from full expensing for tax purposes of certain property acquired and placed in service after September 27, 2017 and continues certain rate normalization requirements for accelerated depreciation benefits.

At the date of enactment, the Companies' deferred taxes were remeasured based upon the new tax rate expected to apply when temporary differences are realized or settled. For regulated operations, many of the changes in deferred taxes represent amounts probable of collection from or refund to customers, and are recorded as either an increase to a regulatory asset or liability. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes may be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred taxes may be determined by our state and federal regulators. For nonregulated operations, the changes in deferred taxes are recorded as an adjustment to deferred tax expense.

ACCOUNTING FOR DERIVATIVE CONTRACTS AND FINANCIAL INSTRUMENTS AT FAIR VALUE

Dominion Energy uses derivative contracts such as physical and financial forwards, futures, swaps, options and FTRs to manage commodity, interest rate and foreign currency exchange rate risks of its business operations. Derivative contracts, with certain exceptions, are reported in the Consolidated Balance Sheets at fair

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value. The majority of investments held in Dominion Energy's nuclear decommissioning and rabbi trusts and pension and other postretirement funds are also subject to fair value accounting. See Notes 6 and 21 to the Consolidated Financial Statements for further information on these fair value measurements.

Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, management seeks indicative price information from external sources, including broker quotes and industry publications. When evaluating pricing information provided by brokers and other pricing services, Dominion Energy considers whether the broker is willing and able to trade at the quoted price, if the broker quotes are based on an active market or an inactive market and the extent to which brokers are utilizing a particular model if pricing is not readily available. If pricing information from external sources is not available, or if Dominion Energy believes that observable pricing information is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases, Dominion Energy must estimate prices based on available historical and near-term future price information and use of statistical methods, including regression analysis, that reflect its market assumptions.

Dominion Energy maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value.

USE OF ESTIMATES IN GOODWILL IMPAIRMENT TESTING

As of December 31, 2017, Dominion Energy reported $6.4 billion of goodwill in its Consolidated Balance Sheet. A significant portion resulted from the acquisition of the former CNG in 2000 and the Dominion Energy Questar Combination in 2016.

In April of each year, Dominion Energy tests its goodwill for potential impairment, and performs additional tests more frequently if an event occurs or circumstances change in the interim that would more-likely-than-not reduce the fair value of a reporting unit below its carrying amount. The 2017, 2016 and 2015 annual tests and any interim tests did not result in the recognition of any goodwill impairment.

In general, Dominion Energy estimates the fair value of its reporting units by using a combination of discounted cash flows and other valuation techniques that use multiples of earnings for peer group companies and analyses of recent business combinations involving peer group companies. Fair value estimates are dependent on subjective factors such as Dominion Energy's estimate of future cash flows, the selection of appropriate discount and growth rates, and the selection of peer group companies and recent transactions. These underlying assumptions and estimates are made as of a point in time; subsequent modifications, particularly changes in discount rates or growth rates inherent in Dominion Energy's estimates of future cash flows, could result in a future impairment of goodwill. Although Dominion Energy has consistently applied the same methods in developing the assumptions and estimates that underlie the fair value calculations, such as estimates of future cash flows, and based those estimates on relevant information available at the time, such cash flow estimates are highly uncertain by nature and may vary significantly from actual results. If the estimates of future cash flows used in the most recent tests had been 10% lower, the resulting fair values would have still been greater than the carrying values of each of those reporting units tested, indicating that no impairment was present.

See Note 11 to the Consolidated Financial Statements for additional information.

USE OF ESTIMATES IN LONG-LIVED ASSET AND EQUITY METHOD INVESTMENT IMPAIRMENT TESTING

Impairment testing for an individual or group of long-lived assets, including intangible assets with definite lives, and equity method investments is required when circumstances indicate those assets may be impaired. When a long-lived asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. When an equity method investment's carrying amount exceeds its fair value, and the decline in value is deemed to be other-than-temporary, an impairment is recognized to the extent that the fair value is less than its carrying amount. Performing an impairment test on long-lived assets and equity method investments involves judgment in areas such as identifying if circumstances indicate an impairment may exist, identifying and grouping affected assets in the case of long-lived assets, and developing the undiscounted and discounted estimated future cash flows (used to estimate fair value in the absence of a market-based value) associated with the asset, including probability weighting such cash flows to reflect expectations about possible variations in their amounts or timing, expectations about the operations of the long-lived assets and equity method investments and the selection of an appropriate discount rate. When determining whether a long-lived asset or asset group has been impaired, management groups assets at the lowest level that has identifiable cash flows. Although cash flow estimates are based on relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. For example, estimates of future cash flows would contemplate factors which may change over time, such as the expected use of the asset or underlying assets of equity method investees, including future production and sales levels, expected fluctuations of prices of commodities sold and consumed and expected proceeds from dispositions. See Note 9 to the Consolidated Financial Statements for a discussion of impairments related to certain equity method investments.

EMPLOYEE BENEFIT PLANS

Dominion Energy sponsors noncontributory defined benefit pension plans and other postretirement benefit plans for eligible active employees, retirees and qualifying dependents. The projected costs of providing benefits under these plans are dependent, in part, on historical information such as employee demographics, the level of contributions made to the plans and earnings on plan assets. Assumptions about the future, including the expected long-term rate of return on plan assets, discount rates applied to benefit obligations, mortality rates and the anticipated rate of increase in healthcare costs and participant compensation, also have a significant impact on employee benefit costs. The impact of changes in these factors, as well as differences between Dominion Energy's

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assumptions and actual experience, is generally recognized in the Consolidated Statements of Income over the remaining average service period of plan participants, rather than immediately.

The expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and mortality rates are critical assumptions. Dominion Energy determines the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset volatilities and correlations;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major stock market indices; and
- Investment allocation of plan assets. The strategic target asset allocation for Dominion Energy's pension funds is 28% U.S. equity, 18% non-U.S. equity, 35% fixed income, 3% real estate and 16% other alternative investments, such as private equity investments.

Strategic investment policies are established for Dominion Energy's prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include those mentioned above such as employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of Dominion Energy's assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns.

Dominion Energy develops non-investment related assumptions, which are then compared to the forecasts of an independent investment advisor to ensure reasonableness. An internal committee selects the final assumptions. Dominion Energy calculated its pension cost using an expected long-term rate of return on plan assets assumption of 8.75% for 2017, 2016 and 2015. For 2018, the expected long-term rate of return for pension cost assumption is 8.75%. Dominion Energy calculated its other postretirement benefit cost using an expected long-term rate of return on plan assets assumption of 8.50% for 2017, 2016 and 2015. For 2018, the expected long-term rate of return for other postretirement benefit cost assumption is 8.50%. The rate used in calculating other postretirement benefit cost is lower than the rate used in calculating pension cost because of differences in the relative amounts of various types of investments held as plan assets.

Dominion Energy determines discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under its plans. The discount rates used to calculate pension cost and other postretirement benefit cost ranged from 3.31% to 4.50% for pension plans and 3.92% to 4.47% for other postretirement benefit plans in 2017, ranged from 2.87% to 4.99% for pension plans and 3.56% to 4.94% for other postretirement benefit plans in 2016 and were 4.40% in 2015. Dominion Energy selected a discount rate ranging from 3.80% to 3.81% for pension plans and 3.76% for other postretirement benefit plans for determining its December 31, 2017 projected benefit obligations.

Dominion Energy establishes the healthcare cost trend rate assumption based on analyses of various factors including the specific provisions of its medical plans, actual cost trends experienced and projected, and demographics of plan participants. Dominion Energy's healthcare cost trend rate assumption as of December 31, 2017 was 7.00% and is expected to gradually decrease to 5.00% by 2022 and continue at that rate for years thereafter.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion Energy's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion Energy considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion Energy conducted a new experience study as scheduled and, as a result, updated its mortality assumptions.

The following table illustrates the effect on cost of changing the critical actuarial assumptions previously discussed, while holding all other assumptions constant:

		Increase in Net Periodic Cost	
(millions, except percentages)	Change in Actuarial Assumption	Pension Benefits	Other Postretirement Benefits
Discount rate	(0.25)%	$20	$ 3
Long-term rate of return on plan assets	(0.25)%	19	4
Healthcare cost trend rate	1 %	N/A	24

In addition to the effects on cost, at December 31, 2017, a 0.25% decrease in the discount rate would increase Dominion Energy's projected pension benefit obligation by $338 million and its accumulated postretirement benefit obligation by $44 million, while a 1.00% increase in the healthcare cost trend rate would increase its accumulated postretirement benefit obligation by $158 million.

See Note 21 to the Consolidated Financial Statements for additional information on Dominion Energy's employee benefit plans.

New Accounting Standards

See Note 2 to the Consolidated Financial Statements for a discussion of new accounting standards.

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Dominion Energy

RESULTS OF OPERATIONS

Presented below is a summary of Dominion Energy's consolidated results:

Year Ended December 31, (millions, except EPS)	2017	$ Change	2016	$ Change	2015
Net income attributable to Dominion Energy	$2,999	$ 876	$2,123	$ 224	$1,899
Diluted EPS	4.72	1.28	3.44	0.24	3.20

Overview

2017 VS. 2016

Net income attributable to Dominion Energy increased 41%, primarily due to benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate, the Dominion Energy Questar Combination and an absence of charges related to future ash pond and landfill closures. These increases were partially offset by lower renewable energy investment tax credits and charges associated with equity method investments in wind-powered generation facilities.

2016 VS. 2015

Net income attributable to Dominion Energy increased 12%, primarily due to higher renewable energy investment tax credits and the new PJM capacity performance market effective June 2016. These increases were partially offset by a decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields and charges related to future ash pond and landfill closure costs at certain utility generation facilities.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion Energy's results of operations:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Operating Revenue	$12,586	$ 849	$11,737	$ 54	$11,683
Electric fuel and other energy-related purchases	2,301	(32)	2,333	(392)	2,725
Purchased electric capacity	6	(93)	99	(231)	330
Purchased gas	701	242	459	(92)	551
Net Revenue	9,578	732	8,846	769	8,077
Other operations and maintenance	2,875	(189)	3,064	469	2,595
Depreciation, depletion and amortization	1,905	346	1,559	164	1,395
Other taxes	668	72	596	45	551
Other income	165	(85)	250	54	196
Interest and related charges	1,205	195	1,010	106	904
Income tax expense (benefit)	(30)	(685)	655	(250)	905

An analysis of Dominion Energy's results of operations follows:

2017 VS. 2016

Net revenue increased 8%, primarily reflecting:

- A $663 million increase from the operations acquired in the Dominion Energy Questar Combination being included for all of 2017;
- A $97 million electric capacity benefit related to non-utility generators ($133 million) and a benefit due to the annual PJM capacity performance market effective June 2016 ($123 million), partially offset by the annual PJM capacity performance market effective June 2017 ($159 million);
- An $86 million increase due to additional generation output from merchant solar generating projects;
- A $71 million increase in sales to electric utility retail customers due to the effect of changes in customer usage and other factors, including $25 million related to customer growth;
- A $63 million increase from regulated natural gas transmission growth projects placed in service;
- A $46 million increase from rate adjustment clauses associated with electric utility operations; and
- A $34 million increase in services performed for Atlantic Coast Pipeline.

These increases were partially offset by:

- A $144 million decrease from Cove Point import contracts;
- A $114 million decrease due to unfavorable pricing at merchant generation facilities; and
- A decrease in sales to electric utility retail customers from a decrease in cooling degree days during the cooling season of 2017 ($53 million) and a reduction in heating degree days during the heating season of 2017 ($28 million).

Other operations and maintenance decreased 6%, primarily reflecting:

- A $197 million absence of charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $115 million decrease in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income;
- A $78 million benefit from the sale of certain assets associated with nonregulated retail energy marketing operations;
- The absence of organizational design initiative costs ($64 million); and
- A $46 million decrease in storm damage and service restoration costs associated with electric utility operations, partially offset by
- A $162 million increase from the operations acquired in the Dominion Energy Questar Combination being included for all of 2017;
- A $92 million increase in salaries, wages and benefits;
- A $36 million increase in outage costs; and
- A $33 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income.

Depreciation, depletion and amortization increased 22%, primarily due to the operations acquired in the Dominion Energy Questar Combination being included for all of 2017 ($162 million)

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and various growth projects being placed into service ($151 million).

Other taxes increased 12%, primarily due to the operations acquired in the Dominion Energy Questar Combination being included for all of 2017 ($35 million) and increased property taxes related to growth projects placed into service ($27 million).

Other income decreased 34%, primarily due to charges associated with equity method investments in wind-powered generation facilities ($158 million), partially offset by an increase in earnings, excluding charges, from equity method investments ($29 million) and an increase in AFUDC associated with rate-regulated projects ($23 million).

Interest and related charges increased 19%, primarily due to higher long-term debt interest expense resulting from debt issuances in 2016 and 2017 ($171 million) and debt acquired in the Dominion Energy Questar Combination ($37 million).

Income tax expense decreased $685 million, primarily due to benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate ($851 million), partially offset by lower renewable energy investment tax credits ($133 million).

2016 VS. 2015

Net revenue increased 10%, primarily reflecting:

- A $544 million increase from electric utility operations, primarily reflecting:
  - A $225 million electric capacity benefit, primarily due to the new PJM capacity performance market effective June 2016 ($155 million) and the expiration of non-utility generator contracts in 2015 ($58 million);
  - An increase from rate adjustment clauses ($183 million); and
  - The absence of an $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015; and
- A $305 million increase due to the Dominion Energy Questar Combination.

These increases were partially offset by:

- A $47 million decrease from merchant generation operations, primarily due to lower realized prices at certain merchant generation facilities ($64 million) and an increase in planned and unplanned outage days in 2016 ($26 million), partially offset by additional solar generating facilities placed into service ($37 million);
- A $19 million decrease from regulated natural gas transmission operations, primarily due to:
  - A $14 million decrease in gas transportation and storage activities, primarily due to decreased demand charges ($28 million), increased fuel costs ($13 million), contract rate changes ($11 million) and decreased revenue from gathering and extraction services ($8 million), partially offset by expansion projects placed in service ($18 million) and increased regulated gas sales ($20 million); and
  - A $17 million decrease in NGL activities, due to decreased prices ($15 million) and volumes ($2 million); partially offset by
  - A $12 million increase in other revenues, primarily due to an increase in services performed for Atlantic Coast Pipeline ($21 million), partially offset by decreased amortization of deferred revenue associated with conveyed shale development rights ($4 million); and
- A $12 million decrease from regulated natural gas distribution operations, primarily due to a decrease in rate adjustment clause revenue related to low income assistance programs ($26 million) and a decrease in sales to customers due to a reduction in heating degree days ($6 million), partially offset by an increase in AMR and PIR program revenues ($18 million).

Other operations and maintenance increased 18%, primarily reflecting:

- A $148 million increase due to the Dominion Energy Questar Combination, including $58 million of transaction and transition costs;
- A $98 million increase in charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $78 million decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields;
- Organizational design initiative costs ($64 million);
- A $50 million increase in storm damage and service restoration costs, including $23 million for Hurricane Matthew;
- A $20 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income; and
- A $16 million increase due to labor contract renegotiations as well as costs resulting from a union workforce temporary work stoppage; partially offset by
- A $26 million decrease in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income.

Depreciation, depletion and amortization increased 12%, primarily due to various expansion projects being placed into service.

Other income increased 28%, primarily due to an increase in earnings from equity method investments ($55 million) and an increase in AFUDC associated with rate-regulated projects ($12 million), partially offset by lower realized gains (net of investment income) on nuclear decommissioning trust funds ($19 million).

Interest and related charges increased 12%, primarily due to higher long-term debt interest expense resulting from debt issuances in 2016 ($134 million), partially offset by an increase in capitalized interest associated with the Cove Point Liquefaction Project ($45 million).

Income tax expense decreased 28%, primarily due to higher renewable energy investment tax credits ($189 million) and the impact of a state legislative change ($14 million), partially offset by higher pre-tax income ($15 million).

Outlook

Dominion Energy's strategy is to continue focusing on its regulated and long-term contracted businesses while maintaining upside potential in well-positioned nonregulated businesses. The goals of this strategy are to provide EPS growth, a growing dividend and to maintain a stable credit profile. Dominion Energy expects approximately 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

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Dominion Energy's 2018 net income is expected to decrease on a per share basis as compared to 2017 primarily from the following:

- Absence of a benefit from remeasurement of deferred income taxes from the 2017 Tax Reform Act;
- Reduction of solar investment tax credits;
- Increases in interest and related charges;
- An increase in depreciation, depletion, and amortization; and
- Share dilution.

These decreases are expected to be partially offset by the following:

- Revenues from the Liquefaction Project;
- A return to normal weather in its electric utility operations;
- Growth in weather-normalized electric utility sales of approximately 1.5%;
- Construction and operation of growth projects in electric utility operations and associated rate adjustment clause revenue;
- Construction and operation of growth projects in gas transmission and distribution;
- Absence of additional refueling outages at Millstone; and
- A lower effective tax rate, driven by the tax reform.

In addition, if the merger with SCANA is completed in 2018, it would result in a decrease to net income as the result of charges to be incurred for refunds to SCE&G electric customers, write-offs of regulatory assets and transaction costs.

SEGMENT RESULTS OF OPERATIONS

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit or loss. Presented below is a summary of contributions by Dominion Energy's operating segments to net income attributable to Dominion Energy:

Year Ended December 31,	2017		2016		2015	
	Net Income attributable to Dominion Energy	**Diluted EPS**	Net Income attributable to Dominion Energy	Diluted EPS	Net Income attributable to Dominion Energy	Diluted EPS
(millions, except EPS)						
Power Delivery	**$ 531**	**$0.83**	$ 484	$ 0.78	$ 490	$ 0.82
Power Generation	**1,181**	**1.86**	1,397	2.26	1,120	1.89
Gas Infrastructure	**898**	**1.41**	726	1.18	680	1.15
Primary operating segments	**2,610**	**4.10**	2,607	4.22	2,290	3.86
Corporate and Other	**389**	**0.62**	(484)	(0.78)	(391)	(0.66)
Consolidated	**$2,999**	**$4.72**	$2,123	$ 3.44	$1,899	$ 3.20

Power Delivery

Presented below are operating statistics related to Power Delivery's operations:

Year Ended December 31,	2017	% Change	2016	% Change	2015
Electricity delivered (million MWh)	**83.4**	**—%**	83.7	—%	83.9
Degree days:					
Cooling	**1,801**	**(2)**	1,830	(1)	1,849
Heating	**3,104**	**(10)**	3,446	1	3,416
Average electric distribution customer accounts (thousands)(1)	**2,574**	**1**	2,549	1	2,525

(1) Period average.

Presented below, on an after-tax basis, are the key factors impacting Power Delivery's net income contribution:

2017 VS. 2016

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	**$(14)**	**$(0.02)**
Other	**15**	**0.02**
FERC transmission equity return	**14**	**0.02**
Storm damage and service restoration	**14**	**0.02**
Other	**18**	**0.03**
Share dilution	**—**	**(0.02)**
Change in net income contribution	**$47**	**$0.05**

2016 VS. 2015

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ (1)	$ —
Other	1	—
FERC transmission equity return	41	0.07
Storm damage and service restoration	(16)	(0.03)
Depreciation and amortization	(10)	(0.02)
AFUDC return	(8)	(0.01)
Interest expense	(5)	(0.01)
Other	(8)	(0.01)
Share dilution	—	(0.03)
Change in net income contribution	$ (6)	$(0.04)

Power Generation

Presented below are operating statistics related to Power Generation's operations:

Year Ended December 31,	2017	% Change	2016	% Change	2015
Electricity supplied (million MWh):					
Utility	**85.0**	**(3)%**	87.9	3%	85.2
Merchant	**28.9**	**—**	28.9	7	26.9
Degree days (electric utility service area):					
Cooling	**1,801**	**(2)**	1,830	(1)	1,849
Heating	**3,104**	**(10)**	3,446	1	3,416

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Presented below, on an after-tax basis, are the key factors impacting Power Generation's net income contribution:

2017 VS. 2016

(millions, except EPS)	Increase (Decrease) Amount	EPS
Regulated electric sales:		
Weather	$ (36)	$(0.06)
Other	32	0.05
Electric capacity	58	0.09
Depreciation and amortization	(46)	(0.07)
Renewable energy investment tax credits	(133)	(0.21)
Merchant generation margin	(28)	(0.04)
Interest expense	(25)	(0.04)
Outage costs	(22)	(0.03)
Other	(16)	(0.03)
Share dilution	—	(0.06)
Change in net income contribution	$(216)	$(0.40)

2016 VS. 2015

(millions, except EPS)	Increase (Decrease) Amount	EPS
Regulated electric sales:		
Weather	$ 2	$ —
Other	13	0.02
Renewable energy investment tax credits	186	0.31
Electric capacity	137	0.23
Merchant generation margin	(34)	(0.06)
Rate adjustment clause equity return	24	0.04
Noncontrolling interest(1)	(28)	(0.05)
Depreciation and amortization	(25)	(0.04)
Other	2	0.01
Share dilution	—	(0.09)
Change in net income contribution	$277	$ 0.37

(1) Represents noncontrolling interest related to merchant solar partnerships.

Gas Infrastructure

Presented below are selected operating statistics related to Gas Infrastructure's operations.

Year Ended December 31,	2017	% Change	2016	% Change	2015
Gas distribution throughput (bcf)(1):					
Sales	130	113%	61	126%	27
Transportation	654	22	537	14	470
Heating degree days (gas distribution service area):					
Eastern region	4,930	(6)	5,235	(8)	5,666
Western region(1)	4,892	161	1,876	100	—
Average gas distribution customer accounts (thousands)(1)(2):					
Sales	1,240	—	1,234(3)	414	240
Transportation	1,086	1	1,071	1	1,057
Average retail energy marketing customer accounts (thousands)(2)	1,405	2	1,376	6	1,296

(1) Includes Dominion Energy Questar effective September 2016.
(2) Period average.
(3) Includes Dominion Energy Questar customer accounts for the entire year.

Presented below, on an after-tax basis, are the key factors impacting Gas Infrastructure's net income contribution:

2017 VS. 2016

(millions, except EPS)	Increase (Decrease) Amount	EPS
Dominion Energy Questar Combination	$184	$ 0.30
Sale of certain retail energy marketing assets	48	0.08
Assignment of shale development rights	13	0.02
Noncontrolling interest(1)	(30)	(0.05)
Cove Point import contracts	(86)	(0.14)
Transportation and storage growth projects	29	0.04
Other	14	0.02
Share dilution	—	(0.04)
	$172	$ 0.23

(1) Represents the portion of earnings attributable to Dominion Energy Midstream's public unitholders.

2016 VS. 2015

(millions, except EPS)	Increase (Decrease) Amount	EPS
Gas distribution margin:		
Weather	$ (4)	$(0.01)
Rate adjustment clauses	11	0.02
Other	6	0.01
Assignment of shale development rights	(48)	(0.08)
Dominion Energy Questar Combination	78	0.13
Other	3	0.01
Share dilution	—	(0.05)
Change in net income contribution	$ 46	$ 0.03

Corporate and Other

Presented below are the Corporate and Other segment's after-tax results:

Year Ended December 31, (millions, except EPS amounts)	2017	2016	2015
Specific items attributable to operating segments	$ 861	$ (180)	$ (136)
Specific items attributable to Corporate and Other segment	(151)	(44)	(5)
Total specific items	710	(224)	(141)
Other corporate operations	(321)	(260)	(250)
Total net expense	$ 389	$ (484)	$ (391)
EPS impact	$0.62	$(0.78)	$(0.66)

TOTAL SPECIFIC ITEMS

Corporate and Other includes specific items attributable to Dominion Energy's primary operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources. See Note 25 to the Consolidated Financial Statements for discussion of these items in more detail. Corporate and Other also includes specific items attributable to the Corporate and Other segment. In 2017, this primarily included $124 million of tax benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate. In 2016, this primarily included $53 million of after-tax transaction and transition costs associated with the Dominion Energy Questar Combination.

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Management's Discussion and Analysis of Financial Condition and Results of Operations, Continued

VIRGINIA POWER

RESULTS OF OPERATIONS

Presented below is a summary of Virginia Power's consolidated results:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Net Income	**$1,540**	**$322**	$1,218	$131	$1,087

Overview

2017 VS. 2016

Net income increased 26%, primarily due to the absence of charges related to future ash pond and landfill closures costs, a benefit from the remeasurement of deferred income taxes to the new corporate income tax rate and an electric capacity benefit.

2016 VS. 2015

Net income increased 12%, primarily due to the new PJM capacity performance market effective June 2016, an increase in rate adjustment clause revenue and the absence of a write-off of deferred fuel costs associated with the Virginia legislation enacted in February 2015. These increases were partially offset by charges related to future ash pond and landfill closure costs at certain utility generation facilities.

Analysis of Consolidated Operations

Presented below are selected amounts related to Virginia Power's results of operations:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Operating Revenue	**$7,556**	**$ (32)**	$7,588	$ (34)	$7,622
Electric fuel and other energy-related purchases	**1,909**	**(64)**	1,973	(347)	2,320
Purchased electric capacity	**6**	**(93)**	99	(231)	330
Net Revenue	**5,641**	**125**	5,516	544	4,972
Other operations and maintenance	**1,478**	**(379)**	1,857	223	1,634
Depreciation and amortization	**1,141**	**116**	1,025	72	953
Other taxes	**290**	**6**	284	20	264
Other income	**76**	**20**	56	(12)	68
Interest and related charges	**494**	**33**	461	18	443
Income tax expense	**774**	**47**	727	68	659

An analysis of Virginia Power's results of operations follows:

2017 VS. 2016

Net revenue increased 2%, primarily reflecting:

- A $97 million electric capacity benefit related to non-utility generators ($133 million) and a benefit due to the annual PJM capacity performance market effective June 2016 ($123 million), partially offset by the annual PJM capacity performance market effective June 2017 ($159 million);
- A $71 million increase in sales to retail customers due to the effect of changes in customer usage and other factors, including $25 million related to customer growth; and
- A $46 million increase from rate adjustment clauses; partially offset by
- A decrease in sales to retail customers from a decrease in cooling degree days during the cooling season of 2017 ($53 million) and a reduction in heating degree days during the heating season of 2017 ($28 million).

Other operations and maintenance decreased 20%, primarily reflecting:

- A $197 million decrease due to the absence of charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $115 million decrease in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income;
- A $46 million decrease in storm damage and service restoration costs; and
- The absence of organizational design initiative costs ($32 million); partially offset by
- A $37 million increase in salaries, wages and benefits and general administrative expenses.

Depreciation and amortization increased 11%, primarily due to various growth projects being placed into service ($58 million) and revised depreciation rates ($40 million).

Other income increased 36%, primarily reflecting:

- An $11 million increase in interest income associated with the settlement of state income tax refund claims;
- An $11 million increase from the assignment of Virginia Power's electric transmission tower rental portfolio; and
- An $8 million increase in AFUDC associated with rate-regulated projects; partially offset by
- A $16 million charge associated with a customer settlement.

Income tax expense increased 6% primarily due to higher pre-tax income ($139 million), partially offset by benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate ($93 million).

2016 VS. 2015

Net revenue increased 11%, primarily reflecting:

- A $225 million electric capacity benefit, primarily due to the new PJM capacity performance market effective June 2016 ($155 million) and the expiration of non-utility generator contracts in 2015 ($58 million);
- An increase from rate adjustment clauses ($183 million); and
- The absence of an $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015.

Other operations and maintenance increased 14%, primarily reflecting:

- A $98 million increase in charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $50 million increase in storm damage and service restoration costs, including $23 million for Hurricane Matthew;
- A $37 million increase in salaries, wages and benefits and general administrative expenses; and
- Organizational design initiative costs ($32 million).

Income tax expense increased 10%, primarily reflecting higher pre-tax income.

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DOMINION ENERGY GAS

RESULTS OF OPERATIONS

Presented below is a summary of Dominion Energy Gas' consolidated results:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Net Income	**$615**	**$223**	$392	$(65)	$457

Overview

2017 VS. 2016

Net income increased 57%, primarily due to a benefit from the remeasurement of deferred income taxes to the new corporate income tax rate and gas transportation and storage activities from growth projects placed into service.

2016 VS. 2015

Net income decreased 14%, primarily due a decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion Energy Gas' results of operations:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Operating Revenue	**$1,814**	**$ 176**	$1,638	$(78)	$1,716
Purchased gas	**132**	**23**	109	(24)	133
Other energy-related purchases	**21**	**9**	12	(9)	21
Net Revenue	**1,661**	**144**	1,517	(45)	1,562
Other operations and maintenance	**527**	**53**	474	84	390
Depreciation and amortization	**227**	**23**	204	(13)	217
Other taxes	**185**	**15**	170	4	166
Earnings from equity method investee	**21**	**—**	21	(2)	23
Other income	**20**	**9**	11	10	1
Interest and related charges	**97**	**3**	94	21	73
Income tax expense	**51**	**(164)**	215	(68)	283

An analysis of Dominion Energy Gas' results of operations follows:

2017 VS. 2016

Net revenue increased 9%, primarily reflecting:

- A $55 million increase due to regulated natural gas transmission growth projects placed in service;
- A $34 million increase in services performed for Atlantic Coast Pipeline;
- A $24 million increase in PIR program revenues; and
- A $16 million increase in rate recovery for low income assistance programs associated with regulated natural gas distribution operations.

Other operations and maintenance increased 11%, primarily reflecting:

- A $33 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income;
- A $16 million increase in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income;
- A $15 million increase due to a charge to write-off the balance of a regulatory asset no longer considered probable of recovery; and
- A $13 million increase in salaries, wages and benefits and general administrative expenses; partially offset by
- A $25 million increase in gains from agreements to convey shale development rights underneath several natural gas storage fields.

Depreciation and amortization increased 11%, primarily due to growth projects being placed into service.

Other income increased 82%, primarily due to a $12 million increase in AFUDC associated with rate-regulated projects, partially offset by the absence of the 2016 sale of a portion of Dominion Energy Gas' interest in Iroquois ($5 million).

Income tax expense decreased 76%, primarily due to benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate ($197 million), partially offset by higher pre-tax income ($22 million).

2016 VS. 2015

Net revenue decreased 3%, primarily reflecting:

- A $34 million decrease from regulated natural gas transmission operations, primarily reflecting:
  - A $36 million decrease in gas transportation and storage activities, primarily due to decreased demand charges ($28 million), increased fuel costs ($13 million), contract rate changes ($11 million) and decreased revenue from gathering and extraction services ($8 million), partially offset by increased regulated gas sales ($16 million) and expansion projects placed in service ($9 million); and
  - An $18 million decrease from NGL activities, due to decreased prices ($16 million) and volumes ($2 million); partially offset by
  - A $21 million increase in services performed for Atlantic Coast Pipeline; and
- A $12 million decrease from regulated natural gas distribution operations, primarily reflecting:
  - A decrease in rate adjustment clause revenue related to low income assistance programs ($26 million); and
  - A $9 million decrease in other revenue primarily due to a decrease in pooling and metering activities ($3 million), a decrease in Blue Racer management fees ($3 million) and a decrease in gathering activities ($2 million); partially offset by
  - An $18 million increase in AMR and PIR program revenues; and
  - An $8 million increase in off-system sales.

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Other operations and maintenance increased 22%, primarily reflecting:

- A $78 million decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields; and
- A $20 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income; partially offset by
- A $26 million decrease in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income.

Other income increased $10 million, primarily due to a gain on the sale of 0.65% of the noncontrolling partnership interest in Iroquois ($5 million) and an increase in AFUDC associated with rate-regulated projects ($5 million).

Interest and related charges increased 29%, primarily due to higher interest expense resulting from the issuances of senior notes in November 2015 and the second quarter of 2016 ($28 million), partially offset by an increase in deferred rate adjustment clause interest expense ($7 million).

Income tax expense decreased 24% primarily reflecting lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

Dominion Energy depends on both internal and external sources of liquidity to provide working capital and as a bridge to long-term debt financings. Short-term cash requirements not met by cash provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

At December 31, 2017, Dominion Energy had $2.1 billion of unused capacity under its credit facilities. See additional discussion below under *Credit Facilities and Short-Term Debt.*

A summary of Dominion Energy's cash flows is presented below:

Year Ended December 31,	2017	2016	2015
(millions)			
Cash and cash equivalents at beginning of year	**$ 261**	$ 607	$ 318
Cash flows provided by (used in):			
Operating activities	**4,549**	4,127	4,475
Investing activities	**(5,993)**	(10,703)	(6,503)
Financing activities	**1,303**	6,230	2,317
Net increase (decrease) in cash and cash equivalents	**(141)**	(346)	289
Cash and cash equivalents at end of year	**$ 120**	$ 261	$ 607

Operating Cash Flows

Net cash provided by Dominion Energy's operating activities increased $422 million, primarily due to the operations acquired in the Dominion Energy Questar combination being included for all of 2017, derivative activities, and lower income tax payments, partially offset by lower deferred fuel cost recoveries in the Virginia jurisdiction, higher interest expense, lower revenue from Cove Point's import contracts and higher pension and postretirement benefit payments and funding.

Dominion Energy believes that its operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and maintain or grow the dividend on common shares. In December 2017, Dominion Energy's Board of Directors established an annual dividend rate for 2018 of $3.34 per share of common stock, a 10.0% increase over the 2017 rate. Dividends are subject to declaration by the Board of Directors. In January 2018, Dominion Energy's Board of Directors declared dividends payable in March 2018 of 83.5 cents per share of common stock.

Beginning in 2018, the 2017 Tax Reform Act is expected to reduce customer rates due to lower income tax expense recoveries and the settlement of income taxes refundable through future rates. The Companies' regulated utilities continue to work with their respective regulatory commissions to determine the amount and timing of the 2017 Tax Reform Act benefits to customers. FERC has not yet issued guidance on the 2017 Tax Reform Act. The ultimate resolution of the amount and timing of these rate reductions with the Companies' regulators could be material to the Companies' operating cash flows.

Dominion Energy's operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows, and which are discussed in Item 1A. Risk Factors.

CREDIT RISK

Dominion Energy's exposure to potential concentrations of credit risk results primarily from its energy marketing and price risk management activities. Presented below is a summary of Dominion Energy's credit exposure as of December 31, 2017 for these activities. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade(1)	**$19**	**$—**	**$19**
Non-investment grade(2)	**8**	**—**	**8**
No external ratings:			
Internally rated-investment grade(3)	**5**	**—**	**5**
Internally rated-non-investment grade(4)	**63**	**—**	**63**
Total	**$95**	**$—**	**$95**

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody's and Standard & Poor's. The five largest counterparty exposures, combined, for this category represented approximately 14% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 7% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 5% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 38% of the total net credit exposure.

Investing Cash Flows

Net cash used in Dominion Energy's investing activities decreased $4.7 billion, primarily due to the absence of the acquisition of Dominion Energy Questar and decreases in plant construction and other property additions, partially offset by an increase in acquisitions of solar development projects and increased contributions to Atlantic Coast Pipeline.

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Financing Cash Flows and Liquidity

Dominion Energy relies on capital markets as significant sources of funding for capital requirements not satisfied by cash provided by its operations. As discussed in *Credit Ratings*, Dominion Energy's ability to borrow funds or issue securities and the return demanded by investors are affected by credit ratings. In addition, the raising of external capital is subject to certain regulatory requirements, including registration with the SEC for certain issuances.

Dominion Energy currently meets the definition of a well-known seasoned issuer under SEC rules governing the registration, communications and offering processes under the Securities Act of 1933. The rules provide for a streamlined shelf registration process to provide registrants with timely access to capital. This allows Dominion Energy to use automatic shelf registration statements to register any offering of securities, other than those for exchange offers or business combination transactions.

From time to time, Dominion Energy may reduce its outstanding debt and level of interest expense through redemption of debt securities prior to maturity and repurchases in the open market, in privately negotiated transactions, through tender offers or otherwise.

Net cash provided by Dominion Energy's financing activities decreased $4.9 billion, primarily due to the absence of issuances of debt, common stock, and Dominion Energy Midstream common and convertible preferred units utilized to finance the Dominion Energy Questar Combination in 2016.

CREDIT FACILITIES AND SHORT-TERM DEBT

Dominion Energy uses short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, Dominion Energy utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion Energy's credit ratings and the credit quality of its counterparties.

In connection with commodity hedging activities, Dominion Energy is required to provide collateral to counterparties under some circumstances. Under certain collateral arrangements, Dominion Energy may satisfy these requirements by electing to either deposit cash, post letters of credit or, in some cases, utilize other forms of security. From time to time, Dominion Energy may vary the form of collateral provided to counterparties after weighing the costs and benefits of various factors associated with the different forms of collateral. These factors include short-term borrowing and short-term investment rates, the spread over these short-term rates at which Dominion Energy can issue commercial paper, balance sheet impacts, the costs and fees of alternative collateral postings with these and other counterparties and overall liquidity management objectives.

Dominion Energy's commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

December 31, 2017	Facility Limit	Outstanding Commercial Paper(2)	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
Joint revolving credit facility(1)	**$5,000**	**$3,298**	**$ —**	**$1,702**
Joint revolving credit facility(1)	**500**	**—**	**76**	**424**
Total	**$5,500**	**$3,298**	**$76**	**$2,126**

(1) These credit facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to a combined $2.0 billion of letters of credit.

(2) The weighted-average interest rate of the outstanding commercial paper supported by Dominion Energy's credit facilities was 1.61% at December 31, 2017.

Dominion Energy has indicated its intention to replace the existing two joint revolving credit facilities with a $6.0 billion joint revolving credit facility in the first quarter of 2018. Terms and covenants of the new credit facility are expected to be similar to the existing credit facilities, including that Virginia Power, Dominion Energy Gas and Questar Gas will remain as co-borrowers, except that the maturity will be in five years and the maximum allowed total debt to total capital ratio, with respect to Dominion Energy only, will be increased from 65% to 67.5%. In February 2018, Virginia Power, as co-borrower, filed with the Virginia Commission for approval.

In February 2018, Dominion Energy borrowed $950 million under a 364-Day Term Loan Agreement that bears interest at a variable rate. In addition, the agreement contains a maximum allowed total debt to total capital ratio of 67.5%. The proceeds were used for general corporate purposes and to repay debt.

In July 2017, Dominion Energy Questar repaid a $250 million variable rate term loan due in August 2017 at the amount of principal then outstanding plus accrued interest.

In November 2017, Dominion Energy filed an SEC shelf registration for the sale of up to $3.0 billion of variable denomination floating rate demand notes, called Dominion Energy Reliability Investment℠. The registration limits the principal amount that may be outstanding at any one time to $1.0 billion. The notes are offered on a continuous basis and bear interest at a floating rate per annum determined by the Dominion Energy Reliability Investment Committee, or its designee, on a weekly basis. The notes have no stated maturity date, are non-transferable and may be redeemed in whole or in part by Dominion Energy or at the investor's option at any time. The balance as of December 31, 2017 was less than $0.1 million. The notes are short-term debt obligations of Dominion Energy and are reflected as short-term debt on Dominion Energy's Consolidated Balance Sheets. The proceeds will be used for general corporate purposes and to repay debt.

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LONG-TERM DEBT

During 2017, Dominion Energy issued the following long-term public debt:

Type	Principal (millions)	Rate	Maturity
Senior notes	$ 400	1.875%	2019
Senior notes	400	2.750%	2022
Senior notes	100	3.900%	2025
Senior notes	750	3.500%	2027
Senior notes	550	3.800%	2047
Senior notes	200	2.750%	2023
Total notes issued	$2,400		

During 2017, Dominion Energy also issued the following long-term private debt:

- In March 2017, Dominion Energy issued through private placement $300 million of 3.496% senior notes that mature in 2024. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.
- In June 2017, Dominion Energy issued through private placement $500 million of variable rate senior notes that mature in 2019. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.
- In November 2017, Questar Gas issued through private placement $100 million of 3.38% senior notes that mature in 2032. The proceeds were used for general corporate purposes and to repay short-term debt.
- In December 2017, Dominion Energy issued through private placement $300 million of variable rate senior notes that mature in 2020. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.

During 2017, Dominion Energy also remarketed the following long-term debt:

- In May 2017, Dominion Energy successfully remarketed the $1.0 billion 2014 Series A 1.50% RSNs due in 2020 pursuant to the terms of the 2014 Equity Units. In connection with the remarketing, the interest rate on the junior subordinated notes was reset to 2.579%. Dominion Energy did not receive any proceeds from the remarketing. See Note 17 to the Consolidated Financial Statements for more information.

During 2017, Dominion Energy also borrowed the following under a term loan agreement:

- In May 2017, Dominion Solar Projects III, Inc. borrowed $280 million under a term loan agreement that bears interest at a variable rate. The term loan amortizes over an 18-year period and matures in May 2024. The debt is nonrecourse to Dominion Energy and is secured by Dominion Solar Projects III, Inc.'s interest in certain solar facilities. The proceeds were used for general corporate purposes.

During 2017, Dominion Energy repaid the following long-term debt:

- In August 2017, Dominion Energy retired its $75 million variable rate Massachusetts Development Finance Agency Solid Waste Disposal Revenue Bonds, Series 2010B, due in 2041 at the amount of principal then outstanding plus accrued interest.

During 2017, Dominion Energy repaid and repurchased $1.6 billion of long-term debt.

In October 2017, Questar Gas entered into an agreement with certain investors to issue through private placements in April 2018, $50 million of 3.30% 12-year senior notes and $100 million of 3.97% 30-year senior notes. The proceeds will be used for general corporate purposes and to repay short-term debt.

In January 2018, Dominion Energy Questar Pipeline issued through private placement $100 million of 3.53% senior notes and $150 million of 3.91% senior notes that mature in 2028 and 2038, respectively. The proceeds were used for general corporate purposes and to pay maturing long-term debt.

ISSUANCE OF COMMON STOCK AND OTHER EQUITY SECURITIES

Dominion Energy maintains Dominion Energy Direct® and a number of employee savings plans through which contributions may be invested in Dominion Energy's common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans. In January 2014, Dominion Energy began purchasing its common stock on the open market for these plans. In April 2014, Dominion Energy began issuing new common shares for these direct stock purchase plans.

During 2017, Dominion Energy issued 4.3 million shares of common stock totaling $335 million through employee savings plans, direct stock purchase and dividend reinvestment plans and other employee and director benefit plans. Dominion Energy received cash proceeds of $302 million from the issuance of 3.8 million of such shares through Dominion Energy Direct® and employee savings plans. In July 2017, Dominion Energy issued 12.5 million shares under the related stock purchase contracts entered into as part of Dominion Energy's 2014 Equity Units and received proceeds of $1.0 billion.

In January 2018, Dominion Energy issued 6.6 million shares and received cash proceeds of $495 million, net of fees and commissions paid of $5 million through its at-the-market program. See Note 19 to the Consolidated Financial Statements for a description of the at-the-market program.

During 2018, Dominion Energy plans to issue shares for employee savings plans and direct stock purchase and dividend reinvestment plans. In addition, if the merger with SCANA is realized, Dominion Energy would issue 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock outstanding at closing.

REPURCHASE OF COMMON STOCK

Dominion Energy did not repurchase any shares in 2017 and does not plan to repurchase shares during 2018, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which does not count against its stock repurchase authorization.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit

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quality of securities and are not a recommendation to buy, sell or hold securities. Dominion Energy believes that its current credit ratings provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to Dominion Energy may affect its ability to access these funding sources or cause an increase in the return required by investors. Dominion Energy's credit ratings affect its liquidity, cost of borrowing under credit facilities and collateral posting requirements under commodity contracts, as well as the rates at which it is able to offer its debt securities.

Both quantitative (financial strength) and qualitative (business or operating characteristics) factors are considered by the credit rating agencies in establishing an individual company's credit rating. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. The credit ratings for Dominion Energy are affected by its financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies and event risk, if applicable, such as major acquisitions or dispositions.

In January 2018, Moody's affirmed Dominion Energy's senior unsecured debt and commercial paper ratings of Baa2 and P-2, respectively, and Standard & Poor's affirmed Dominion Energy's senior unsecured debt and commercial paper ratings of BBB and A-2, respectively. Moody's and Standard & Poor's each changed Dominion Energy's rating outlook to negative from stable. Dominion Energy cannot predict the potential impact the negative outlook at Moody's and Standard & Poor's could have on its cost of borrowing.

In January 2018, Fitch affirmed Dominion Energy's senior unsecured debt and commercial paper ratings of BBB+ and F2, respectively, and maintained its stable outlook for both ratings.

Credit ratings as of February 23, 2018 follow:

	Fitch	Moody's	Standard & Poor's
Dominion Energy			
Issuer	**BBB+**	**Baa2**	**BBB+**
Senior unsecured debt securities	**BBB+**	**Baa2**	**BBB**
Junior subordinated notes(1)	**BBB**	**Baa3**	**BBB**
Enhanced junior subordinated notes(2)	**BBB-**	**Baa3**	**BBB-**
Junior/ remarketable subordinated notes(2)	**BBB-**	**Baa3**	**BBB-**
Commercial paper	**F2**	**P-2**	**A-2**

(1) Securities do not have an interest deferral feature.
(2) Securities have an interest deferral feature.

As of February 23, 2018, Fitch maintained a stable outlook for its respective ratings of Dominion Energy and Moody's and Standard & Poor's maintained a negative outlook for their respective ratings of Dominion Energy.

A downgrade in an individual company's credit rating does not necessarily restrict its ability to raise short-term and long-term financing as long as its credit rating remains investment grade, but it could result in an increase in the cost of borrowing. Dominion Energy works closely with Fitch, Moody's and Standard & Poor's with the objective of achieving its targeted credit ratings. Dominion Energy may find it necessary to modify its business plan to maintain or achieve appropriate credit ratings and such changes may adversely affect growth and EPS.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, Dominion Energy must enter into enabling agreements. These agreements contain covenants that, in the event of default, could result in the acceleration of principal and interest payments; restrictions on distributions related to capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments; and in some cases, the termination of credit commitments unless a waiver of such requirements is agreed to by the lenders/security holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to Dominion Energy.

Some of the typical covenants include:

- The timely payment of principal and interest;
- Information requirements, including submitting financial reports filed with the SEC and information about changes in Dominion Energy's credit ratings to lenders;
- Performance obligations, audits/inspections, continuation of the basic nature of business, restrictions on certain matters related to merger or consolidation and restrictions on disposition of all or substantially all assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- Limitations on liens.

Dominion Energy is required to pay annual commitment fees to maintain its credit facilities. In addition, Dominion Energy's credit agreements contain various terms and conditions that could affect its ability to borrow under these facilities. They include maximum debt to total capital ratios and cross-default provisions.

As of December 31, 2017, the calculated total debt to total capital ratio, pursuant to the terms of the agreements, was as follows:

Company	Maximum Allowed Ratio(1)	Actual Ratio(2)
Dominion Energy	**65%**	**62%**

(1) The $950 million 364-Day Term Loan Credit Agreement, borrowed in February 2018, has a maximum allowed total debt to total capital ratio of 67.5%. In addition, the $6.0 billion replacement joint revolving credit facility, expected to be executed in the first quarter of 2018, is expected to increase the maximum allowed total debt to total capital ratio from 65% to 67.5%.
(2) Indebtedness as defined by the bank agreements excludes certain junior subordinated and remarketable subordinated notes reflected as long-term debt as well as AOCI reflected as equity in the Consolidated Balance Sheets.

If Dominion Energy or any of its material subsidiaries fails to make payment on various debt obligations in excess of $100 million, the lenders could require the defaulting company, if it is a borrower under Dominion Energy's credit facilities, to accelerate its repayment of any outstanding borrowings and the lenders could terminate their commitments, if any, to lend funds to that company under the credit facilities. In addition, if the defaulting company is Virginia Power, Dominion Energy's obligations to repay any outstanding borrowing under the credit facilities could also be accelerated and the lenders' commitments to Dominion Energy could terminate.

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Dominion Energy executed RCCs in connection with its issuance of the June 2006 hybrids and September 2006 hybrids. See Note 17 to the Consolidated Financial Statements for additional information, including terms of the RCCs.

At December 31, 2017, the termination dates and covered debt under the RCCs associated with Dominion Energy's hybrids were as follows:

Hybrid	RCC Termination Date	Designated Covered Debt Under RCC
June 2006 hybrids	**6/30/2036**	**September 2006 hybrids**
September 2006 hybrids	**9/30/2036**	**June 2006 hybrids**

Dominion Energy monitors these debt covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2017, there have been no events of default under Dominion Energy's debt covenants.

Dividend Restrictions

Certain agreements associated with Dominion Energy's credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict Dominion Energy's ability to pay dividends or receive dividends from its subsidiaries at December 31, 2017.

See Note 17 to the Consolidated Financial Statements for a description of potential restrictions on dividend payments by Dominion Energy in connection with the deferral of interest payments and contract adjustment payments on certain junior subordinated notes and equity units, initially in the form of corporate units, which information is incorporated herein by reference.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

CONTRACTUAL OBLIGATIONS

Dominion Energy is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financing arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services and financial derivatives. Presented below is a table summarizing cash payments that may result from contracts to which Dominion Energy is a party as of December 31, 2017. For purchase obligations and other liabilities, amounts are based upon contract terms, including fixed and minimum quantities to be purchased at fixed or market-based prices. Actual cash payments will be based upon actual quantities purchased and prices paid and will likely differ from amounts presented below. The table excludes all amounts classified as current liabilities in the Consolidated Balance Sheets, other than current maturities of long-term debt, interest payable and certain derivative instruments. The majority of Dominion Energy's current liabilities will be paid in cash in 2018.

(millions)	2018	2019-2020	2021-2022	2023 and thereafter	Total
Long-term debt(1)	**$3,311**	**$ 6,321**	**$3,719**	**$20,942**	**$34,293**
Interest payments(2)	**1,349**	**2,341**	**1,969**	**14,556**	**20,215**
Leases(3)	**68**	**119**	**87**	**361**	**635**
Purchase obligations(4):					
Purchased electric capacity for utility operations	**93**	**113**	**46**	**—**	**252**
Fuel commitments for utility operations	**1,019**	**820**	**364**	**1,362**	**3,565**
Fuel commitments for nonregulated operations	**115**	**97**	**110**	**165**	**487**
Pipeline transportation and storage	**389**	**712**	**549**	**2,190**	**3,840**
Other(5)	**330**	**107**	**28**	**45**	**510**
Other long-term liabilities(6):					
Other contractual obligations(7)	**151**	**107**	**31**	**153**	**442**
Total cash payments	**$6,825**	**$10,737**	**$6,903**	**$39,774**	**$64,239**

(1) Based on stated maturity dates rather than the earlier redemption dates that could be elected by instrument holders. In February 2018, $250 million of Dominion Energy Questar Pipeline's senior notes were repaid using proceeds from the January 2018 issuance, through private placements, of $100 million and $150 million of senior notes that mature in 2028 and 2038, respectively. As a result, at December 31, 2017, $250 million of senior notes with a 2018 maturity were included in long-term debt in the Consolidated Balance Sheets.

(2) Includes interest payments over the terms of the debt and payments on related stock purchase contracts. Interest is calculated using the applicable interest rate or forward interest rate curve at December 31, 2017 and outstanding principal for each instrument with the terms ending at each instrument's stated maturity. See Note 17 to the Consolidated Financial Statements. Does not reflect Dominion Energy's ability to defer interest and stock purchase contract payments on certain junior subordinated notes or RSNs and equity units, initially in the form of Corporate Units.

(3) Primarily consists of operating leases.

(4) Amounts exclude open purchase orders for services that are provided on demand, the timing of which cannot be determined.

(5) Includes capital, operations, and maintenance commitments.

(6) Excludes regulatory liabilities, AROs and employee benefit plan obligations, which are not contractually fixed as to timing and amount. See Notes 12, 14 and 21 to the Consolidated Financial Statements. Due to uncertainty about the timing and amounts that will ultimately be paid, $27 million of income taxes payable associated with unrecognized tax benefits are excluded. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year. See Note 5 to the Consolidated Financial Statements.

(7) Includes interest rate and foreign currency swap agreements.

PLANNED CAPITAL EXPENDITURES

Dominion Energy's planned capital expenditures are expected to total approximately $5.5 billion, $5.2 billion and $4.8 billion in 2018, 2019 and 2020, respectively. Dominion Energy's planned expenditures are expected to include construction and expansion of electric generation and natural gas transmission and storage facilities, construction improvements and expansion of electric transmission and distribution assets, purchases of nuclear fuel, maintenance and Dominion Energy's portion of the Atlantic Coast Pipeline.

Dominion Energy expects to fund its capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings. Planned capital expenditures include capital projects that are subject to approval by regulators and the Board of Directors.

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See *Power Delivery, Power Generation* and *Gas Infrastructure - Properties* in Item 1. Business for a discussion of Dominion Energy's expansion plans.

These estimates are based on a capital expenditures plan reviewed and endorsed by Dominion Energy's Board of Directors in late 2017 and are subject to continuing review and adjustment and actual capital expenditures may vary from these estimates. Dominion Energy may also choose to postpone or cancel certain planned capital expenditures in order to mitigate the need for future debt financings and equity issuances.

Use of Off-Balance Sheet Arrangements

Leasing Arrangement

In July 2016, Dominion Energy signed an agreement with a lessor to construct and lease a new corporate office property in Richmond, Virginia. The lessor is providing equity and has obtained financing commitments from debt investors, totaling $365 million, to fund the estimated project costs. The project is expected to be completed by mid-2019. Dominion Energy has been appointed to act as the construction agent for the lessor, during which time Dominion Energy will request cash draws from the lessor and debt investors to fund all project costs, which totaled $139 million as of December 31, 2017. If the project is terminated under certain events of default, Dominion Energy could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion Energy could be required to pay up to 100% of the then funded amount.

The five-year lease term will commence once construction is substantially complete and the facility is able to be occupied. At the end of the initial lease term, Dominion Energy can (i) extend the term of the lease for an additional five years, subject to the approval of the participants, at current market terms, (ii) purchase the property for an amount equal to the project costs or, (iii) subject to certain terms and conditions, sell the property on behalf of the lessor to a third party using commercially reasonable efforts to obtain the highest cash purchase price for the property. If the project is sold and the proceeds from the sale are insufficient to repay the investors for the project costs, Dominion Energy may be required to make a payment to the lessor, up to 87% of project costs, for the difference between the project costs and sale proceeds.

The respective transactions have been structured so that Dominion Energy is not considered the owner during construction for financial accounting purposes and, therefore, will not reflect the construction activity in its consolidated financial statements. The financial accounting treatment of the lease agreement will be impacted by the new accounting standard issued in February 2016. See Note 2 to the Consolidated Financial Statements for additional information. Dominion Energy will be considered the owner of the leased property for tax purposes, and as a result, will be entitled to tax deductions for depreciation and interest expense.

Guarantees

Dominion Energy primarily enters into guarantee arrangements on behalf of its consolidated subsidiaries. These arrangements are not subject to the provisions of FASB guidance that dictate a guarantor's accounting and disclosure requirements for guarantees, including indirect guarantees of indebtedness of others. In addition, Dominion Energy has provided a guarantee to support a portion of Atlantic Coast Pipeline's obligation under a $3.4 billion revolving credit facility. See Note 22 to the Consolidated Financial Statements for additional information, which information is incorporated herein by reference.

Future Issues and Other Matters

See Item 1. Business and Notes 13 and 22 to the Consolidated Financial Statements for additional information on various environmental, regulatory, legal and other matters that may impact future results of operations, financial condition and/or cash flows.

Environmental Matters

Dominion Energy is subject to costs resulting from a number of federal, state, tribal and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

Environmental Protection and Monitoring Expenditures

Dominion Energy incurred $200 million, $394 million and $298 million of expenses (including accretion and depreciation) during, 2017, 2016 and 2015 respectively, in connection with environmental protection and monitoring activities and expects these expenses to be approximately $190 million and $185 million in 2018 and 2019, respectively. In addition, capital expenditures related to environmental controls were $201 million, $191 million, and $94 million for 2017, 2016 and 2015, respectively. These expenditures are expected to be approximately $205 million and $135 million for 2018 and 2019, respectively.

Future Environmental Regulations

Air

The CAA is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, delegated states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

In August 2015, the EPA issued final carbon standards for existing fossil fuel power plants. Known as the Clean Power Plan, the rule uses a set of measures for reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units and expanding renewable resources. The final rule has been challenged in the U.S. Court of Appeals for the D.C. Circuit. In February 2016, the U.S. Supreme Court issued a stay of the Clean Power Plan until the disposition of the petitions challenging the rule now before the Court of Appeals, and, if such petitions are filed in the future, before the U.S. Supreme Court. Pursuant to an Executive Order directing the EPA to undertake a review of the Clean Power Plan, the EPA issued a proposed rule in October 2017 to repeal the Clean Power Plan on the basis that the rule promulgated in 2015 exceeds the

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EPA's authority under the CAA. In December 2017, the EPA issued an Advanced Notice of Proposed Rulemaking to solicit input on whether it should proceed with a rule to replace the Clean Power Plan, and if so, what the scope of such a rule should be. Given these developments and associated federal and state regulatory and legal uncertainties, Dominion Energy cannot predict the potential financial statement impacts but believes the potential expenditures to comply could be material.

Climate Change

In December 2015, the Paris Agreement was formally adopted under the United Nations Framework Convention on Climate Change. A key element of the initial U.S. commitment to the agreement was the implementation of the Clean Power Plan, which the EPA has proposed to repeal. In June 2017, the Administration announced that the U.S. intends to file to withdraw from the Paris Agreement in 2019. Several states, including Virginia, subsequently announced a commitment to achieving the carbon reduction goals of the Paris Agreement. It is not possible at this time to predict the timing and impact of this withdrawal, or how any legal requirements in the U.S. at the federal, state or local levels pursuant to the Paris Agreement could impact the Companies' customers or the business.

In March 2016, the EPA began development of regulations for reducing methane emissions from existing sources in the oil and natural gas sectors. In November 2016, the EPA issued an Information Collection Request to collect information on existing sources upstream of local distribution companies in this sector. In March 2017, the EPA withdrew the information collection request and it remains unclear whether the EPA may propose new regulations on existing sources. Dominion Energy cannot currently estimate the potential impacts on results of operations, financial condition and/or cash flows related to this matter.

State Actions Related to Air and GHG Emissions

In August 2017, the Ozone Transport Commission released a draft model rule for control of NO_x emissions from natural gas pipeline compressor fuel-fire prime movers. States within the ozone transport region, including states in which Dominion Energy has natural gas operations, are expected to develop reasonably achievable control technology rules for existing sources based on the Ozone Transport Commission model rule. States outside of the Ozone Transport Commission may also consider the model rules in setting new reasonably achievable control technology standards. Several states in which Dominion Energy operates, including Pennsylvania, New York and Maryland, are developing state-specific regulations to control GHG emissions, including methane. In January 2018, the VDEQ published for comment a proposed state carbon regulation program linked to RGGI. Dominion Energy cannot currently estimate the potential financial statements impacts on results of operations, financial condition and/or cash flows related to these matters.

PHMSA Regulation

The most recent reauthorization of PHMSA included new provisions on historical records research, maximum-allowed operating pressure validation, use of automated or remote-controlled valves on new or replaced lines, increased civil penalties and evaluation of expanding integrity management beyond high-consequence areas. PHMSA has not yet issued new rulemaking on most of these items.

Dodd-Frank Act

The Dodd-Frank Act was enacted into law in July 2010 in an effort to improve regulation of financial markets. The CEA, as amended by Title VII of the Dodd-Frank Act, requires certain over-the counter derivatives, or swaps, to be cleared through a derivatives clearing organization and, if the swap is subject to a clearing requirement, to be executed on a designated contract market or swap execution facility. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end users, may elect the end-user exception to the CEA's clearing requirements. Dominion Energy has elected to exempt its swaps from the CEA's clearing requirements. If, as a result of changes to the rulemaking process, Dominion Energy's derivative activities are not exempted from clearing, exchange trading or margin requirements, it could be subject to higher costs due to decreased market liquidity or increased margin payments. In addition, Dominion Energy's swap dealer counterparties may attempt to pass-through additional trading costs in connection with changes to or the elimination of rulemaking that implements Title VII of the Dodd-Frank Act. Due to the evolving rulemaking process, Dominion Energy is currently unable to assess the potential impact of the Dodd-Frank Act's derivative-related provisions on its financial condition, results of operations or cash flows.

Virginia Legislation

PROPOSED GRID TRANSFORMATION AND SECURITY ACT OF 2018

In January 2018, legislation was introduced in the Virginia General Assembly to reinstate base rate reviews on a triennial basis other than the first review, which will be a quadrennial review, occurring for Virginia Power in 2021 for the four successive 12-month test periods beginning January 1, 2017 and ending December 31, 2020. This review for Virginia Power will occur one year earlier than under the Regulation Act legislation enacted in February 2015.

In the triennial review proceedings, earnings that are more than 70 basis points above the utility's authorized return on equity that might have been refunded to customers may be reduced by any prior investment amounts for new solar or wind generation facilities or up to 5,000 MW of new solar or wind generation facilities and electric distribution grid transformation projects that Virginia Power elects to include in a customer credit reinvestment offset. The legislation declares that electric distribution grid transformation projects are in the public interest and provides that the costs of such projects may be recovered through a rate adjustment clause if not the subject of a customer credit reinvestment offset. Any costs that are the subject of a customer credit reinvestment offset may not be recovered in base rates for the service life of the projects and may not be included in base rates in future triennial review proceedings.

The legislation also includes provisions requiring Virginia Power to provide current customers a one-time bill credit of

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$200 million and to reduce base rates to reflect reductions in federal tax liability resulting from the enactment of the 2017 Tax Reform Act. The legislation is pending.

Other Matters

While management currently has no plans which may affect the carrying value of Millstone, based on potential future economic and other factors, including, but not limited to, market power prices, results of capacity auctions, legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free generation, and the impact of potential EPA carbon rules; there is risk that Millstone may be evaluated for an early retirement date. Should management make any decision on a potential early retirement date, the precise date and the resulting financial statement impacts, which could be material to Dominion Energy, may be affected by a number of factors, including any potential regulatory or legislative solutions, results of any transmission system reliability study assessments, and decommissioning requirements, among other factors.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The matters discussed in this Item may contain "forward-looking statements" as described in the introductory paragraphs of Item 7. MD&A. The reader's attention is directed to those paragraphs and Item 1A. Risk Factors for discussion of various risks and uncertainties that may impact the Companies.

MARKET RISK SENSITIVE INSTRUMENTS AND RISK MANAGEMENT

The Companies' financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is present in Dominion Energy's and Virginia Power's electric operations and Dominion Energy's and Dominion Energy Gas' natural gas procurement and marketing operations due to the exposure to market shifts in prices received and paid for electricity, natural gas and other commodities. The Companies use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to their outstanding debt and future issuances of debt. In addition, the Companies are exposed to investment price risk through various portfolios of equity and debt securities.

The following sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10% change in commodity prices or interest rates.

Commodity Price Risk

To manage price risk, Dominion Energy and Virginia Power hold commodity-based derivative instruments held for non-trading purposes associated with purchases and sales of electricity, natural gas and other energy-related products and Dominion Energy Gas primarily holds commodity-based financial derivative instruments held for non-trading purposes associated with purchases and sales of natural gas and other energy-related products.

The derivatives used to manage commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps, options and FTRs that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the hypothetical change in market prices of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on observable market prices.

A hypothetical 10% decrease in commodity prices would have resulted in a decrease in fair value of $5 million and $27 million of Dominion Energy's commodity-based derivative instruments as of December 31, 2017 and December 31, 2016, respectively. The decrease in sensitivity is largely due to a decrease in commodity derivative activity and changes in commodity prices.

A hypothetical 10% decrease in commodity prices would have resulted in a decrease in the fair value of $51 million and $62 million of Virginia Power's commodity-based derivative instruments as of December 31, 2017 and December 31, 2016, respectively. The decrease in sensitivity is largely due to a decrease in commodity derivative activity and lower commodity prices.

A hypothetical 10% increase in commodity prices of Dominion Energy Gas' commodity-based financial derivative instruments would have resulted in a decrease in fair value of $4 million as of both December 31, 2017 and 2016.

The impact of a change in energy commodity prices on the Companies' commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from physical sales of the commodity.

Interest Rate Risk

The Companies manage their interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. They also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For variable rate debt and interest rate swaps designated under fair value hedging and outstanding for the Companies, a hypothetical 10% increase in market interest rates would not have resulted in a material change in annual earnings at December 31, 2017 or 2016.

The Companies also use interest rate derivatives, including forward-starting swaps, as cash flow hedges of forecasted interest payments. As of December 31, 2017, Dominion Energy and Virginia Power had $3.5 billion and $1.5 billion, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of $86 million and $67 million, respectively, in the fair value of Dominion Energy's and Virginia Power's interest rate derivatives at December 31, 2017. As of December 31, 2016, Dominion Energy and Virginia Power had

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$2.9 billion and $1.7 billion, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of $58 million and $45 million, respectively, in the fair value of Dominion Energy's and Virginia Power's interest rate derivatives at December 31, 2016.

During 2016, Dominion Energy Gas entered into foreign currency swaps with the purpose of hedging the foreign currency exchange risk associated with Euro denominated debt. As of December 31, 2017, Dominion Energy and Dominion Energy Gas had $280 million (€ 250 million) in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% increase in market interest rates would have resulted in a $6 million decrease in the fair value of Dominion Energy's and Dominion Energy Gas' foreign currency swaps at December 31, 2017. As of December 31, 2016, Dominion Energy and Dominion Energy Gas had $280 million (€ 250 million) in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% increase in market interest rates would have resulted in a $5 million decrease in the fair value of Dominion Energy's and Dominion Energy Gas's foreign currency swaps at December 31, 2016.

The impact of a change in interest rates on the Companies' interest rate-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net gains and/or losses from interest rate derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction.

Investment Price Risk

Dominion Energy and Virginia Power are subject to investment price risk due to securities held as investments in nuclear decommissioning and rabbi trust funds that are managed by third-party investment managers. These trust funds primarily hold marketable securities that are reported in the Consolidated Balance Sheets at fair value.

Dominion Energy recognized net realized gains (including investment income) on nuclear decommissioning and rabbi trust investments of $167 million and $144 million in 2017 and 2016, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. Dominion Energy recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains of $462 million and $183 million in 2017 and 2016, respectively.

Virginia Power recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $76 million and $67 million in 2017 and 2016, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. Virginia Power recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains of $216 million and $93 million in 2017 and 2016, respectively.

Dominion Energy sponsors pension and other postretirement employee benefit plans that hold investments in trusts to fund employee benefit payments. Virginia Power and Dominion Energy Gas employees participate in these plans. Dominion Energy's pension and other postretirement plan assets experienced aggregate actual returns of $1.6 billion and $534 million in 2017 and 2016, respectively, versus expected returns of $767 million and $691 million, respectively. Dominion Energy Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $335 million and $130 million in 2017 and 2016, respectively, versus expected returns of $165 million and $157 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans. A hypothetical 0.25% decrease in the assumed long-term rates of return on Dominion Energy's plan assets would result in an increase in net periodic cost of $19 million and $18 million as of December 31, 2017 and 2016, respectively, for pension benefits and $4 million as of both December 31, 2017 and 2016, for other postretirement benefits. A hypothetical 0.25% decrease in the assumed long-term rates of return on Dominion Energy Gas' plan assets, for employees represented by collective bargaining units, would result in an increase in net periodic cost of $4 million as of both December 31, 2017 and 2016, for pension benefits and $1 million as of both December 31, 2017 and 2016, for other postretirement benefits.

Risk Management Policies

The Companies have established operating procedures with corporate management to ensure that proper internal controls are maintained. In addition, Dominion Energy has established an independent function at the corporate level to monitor compliance with the credit and commodity risk management policies of all subsidiaries, including Virginia Power and Dominion Energy Gas. Dominion Energy maintains credit policies that include the evaluation of a prospective counterparty's financial condition, collateral requirements where deemed necessary and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, Dominion Energy also monitors the financial condition of existing counterparties on an ongoing basis. Based on these credit policies and the Companies' December 31, 2017 provision for credit losses, management believes that it is unlikely that a material adverse effect on the Companies' financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

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Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Dominion Energy, Inc.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Dominion Energy, Inc. and subsidiaries ("Dominion Energy") at December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Dominion Energy at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), Dominion Energy's internal control over financial reporting at December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2018, expressed an unqualified opinion on Dominion Energy's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of Dominion Energy's management. Our responsibility is to express an opinion on Dominion Energy's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to Dominion Energy in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

We have served as Dominion Energy's auditor since 1988.

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Dominion Energy, Inc.
Consolidated Statements of Income

Year Ended December 31, (millions, except per share amounts)	2017	2016	2015
Operating Revenue(1)	**$12,586**	$11,737	$11,683
Operating Expenses			
Electric fuel and other energy-related purchases	**2,301**	2,333	2,725
Purchased electric capacity	**6**	99	330
Purchased gas	**701**	459	551
Other operations and maintenance	**2,875**	3,064	2,595
Depreciation, depletion and amortization	**1,905**	1,559	1,395
Other taxes	**668**	596	551
Total operating expenses	**8,456**	8,110	8,147
Income from operations	**4,130**	3,627	3,536
Other income(1)	**165**	250	196
Interest and related charges	**1,205**	1,010	904
Income from operations including noncontrolling interests before income tax expense (benefit)	**3,090**	2,867	2,828
Income tax expense (benefit)	**(30)**	655	905
Net Income Including Noncontrolling Interests	**3,120**	2,212	1,923
Noncontrolling Interests	**121**	89	24
Net Income Attributable to Dominion Energy	**2,999**	2,123	1,899
Earnings Per Common Share			
Net income attributable to Dominion Energy—Basic	**$ 4.72**	$ 3.44	$ 3.21
Net income attributable to Dominion Energy—Diluted	**$ 4.72**	$ 3.44	$ 3.20
Dividends Declared Per Common Share	**$ 3.035**	$ 2.80	$ 2.59

(1) See Note 9 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

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Dominion Energy, Inc.
Consolidated Statements of Comprehensive Income

Year Ended December 31,	2017	2016	2015
(millions)			
Net income including noncontrolling interests	**$3,120**	$2,212	$1,923
Other comprehensive income (loss), net of taxes:			
Net deferred gains on derivatives-hedging activities, net of $(3), $(37) and $(74) tax	**8**	55	110
Changes in unrealized net gains on investment securities, net of $(121), $(53) and $23 tax	**215**	93	6
Changes in net unrecognized pension and other postretirement benefit costs, net of $32, $189 and $29 tax	**(69)**	(319)	(66)
Amounts reclassified to net income:			
Net derivative gains-hedging activities, net of $18, $100 and $68 tax	**(29)**	(159)	(108)
Net realized gains on investment securities, net of $21, $15 and $29 tax	**(37)**	(28)	(50)
Net pension and other postretirement benefit costs, net of $(32), $(22) and $(35) tax	**50**	34	51
Changes in other comprehensive income (loss) from equity method investees, net of $(2), $— and $1 tax	**3**	(1)	(1)
Total other comprehensive income (loss)	**141**	(325)	(58)
Comprehensive income including noncontrolling interests	**3,261**	1,887	1,865
Comprehensive income attributable to noncontrolling interests	**122**	89	24
Comprehensive income attributable to Dominion Energy	**$3,139**	$1,798	$1,841

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

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Dominion Energy, Inc.
Consolidated Balance Sheets

At December 31, (millions)	2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	$ 120	$ 261
Customer receivables (less allowance for doubtful accounts of $17 and $18)	1,660	1,523
Other receivables (less allowance for doubtful accounts of $2 at both dates)(1)	126	183
Inventories		
Materials and supplies	1,049	1,087
Fossil fuel	328	341
Gas Stored	100	96
Prepayments	260	194
Regulatory assets	294	244
Other	397	319
Total current assets	4,334	4,248
Investments		
Nuclear decommissioning trust funds	5,093	4,484
Investment in equity method affiliates	1,544	1,561
Other	327	298
Total investments	6,964	6,343
Property, Plant and Equipment		
Property, plant and equipment	74,823	69,556
Accumulated depreciation, depletion and amortization	(21,065)	(19,592)
Total property, plant and equipment, net	53,758	49,964
Deferred Charges and Other Assets		
Goodwill	6,405	6,399
Pension and other postretirement benefit assets	1,378	1,078
Intangible assets, net	685	618
Regulatory assets	2,480	2,473
Other	581	487
Total deferred charges and other assets	11,529	11,055
Total assets	$ 76,585	$ 71,610

(1) See Note 9 for amounts attributable to related parties.

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At December 31, (millions)	2017	2016
LIABILITIES AND EQUITY		
Current Liabilities		
Securities due within one year	**$ 3,078**	$ 1,709
Short-term debt	**3,298**	3,155
Accounts payable	**875**	1,000
Accrued interest, payroll and taxes	**848**	798
Other(1)	**1,537**	1,453
Total current liabilities	**9,636**	8,115
Long-Term Debt		
Long-term debt	**25,588**	24,878
Junior subordinated notes	**3,981**	2,980
Remarketable subordinated notes	**1,379**	2,373
Total long-term debt	**30,948**	30,231
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**4,523**	8,602
Regulatory liabilities	**6,916**	2,622
Asset retirement obligations	**2,169**	2,236
Pension and other postretirement benefit liability	**2,160**	2,112
Other(1)	**863**	852
Total deferred credits and other liabilities	**16,631**	16,424
Total liabilities	**57,215**	54,770
Commitments and Contingencies (see Note 22)		
Equity		
Common stock-no par(2)	**9,865**	8,550
Retained earnings	**7,936**	6,854
Accumulated other comprehensive loss	**(659)**	(799)
Total common shareholders' equity	**17,142**	14,605
Noncontrolling interests	**2,228**	2,235
Total equity	**19,370**	16,840
Total liabilities and equity	**$76,585**	$71,610

(1) See Notes 3 and 9 for amounts attributable to related parties.
(2) 1 billion shares authorized; 645 million shares and 628 million shares outstanding at December 31, 2017 and 2016, respectively.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

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Dominion Energy, Inc.
Consolidated Statements of Equity

(millions)	Common Stock Shares	Common Stock Amount	Retained Earnings	Dominion Energy Shareholders Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Noncontrolling Interests	Total Equity
December 31, 2014	585	$5,876	$ 6,095	$(416)	$11,555	$ 402	$11,957
Net income including noncontrolling interests			1,899		1,899	24	1,923
Dominion Energy Midstream's acquisition of interest in Iroquois					—	216	216
Acquisition of Four Brothers and Three Cedars					—	47	47
Contributions from SunEdison to Four Brothers and Three Cedars					—	103	103
Sale of interest in merchant solar projects		26			26	179	205
Purchase of Dominion Energy Midstream common units		(6)			(6)	(19)	(25)
Issuance of common stock	11	786			786		786
Stock awards (net of change in unearned compensation)		13			13		13
Dividends			(1,536)		(1,536)		(1,536)
Dominion Energy Midstream distributions					—	(16)	(16)
Other comprehensive loss, net of tax				(58)	(58)		(58)
Other		(15)			(15)	2	(13)
December 31, 2015	596	6,680	6,458	(474)	12,664	938	13,602
Net income including noncontrolling interests			2,123		2,123	89	2,212
Contributions from SunEdison to Four Brothers and Three Cedars					—	189	189
Sale of interest in merchant solar projects		22			22	117	139
Sale of Dominion Energy Midstream common units—net of offering costs					—	482	482
Sale of Dominion Energy Midstream convertible preferred units—net of offering costs					—	490	490
Purchase of Dominion Energy Midstream common units		(3)			(3)	(14)	(17)
Issuance of common stock	32	2,152			2,152		2,152
Stock awards (net of change in unearned compensation)		14			14		14
Present value of stock purchase contract payments related to RSNs(1)		(191)			(191)		(191)
Tax effect of Dominion Energy Questar Pipeline contribution to Dominion Energy Midstream		(116)			(116)		(116)
Dividends and distributions			(1,727)		(1,727)	(62)	(1,789)
Other comprehensive loss, net of tax				(325)	(325)		(325)
Other		(8)			(8)	6	(2)
December 31, 2016	628	8,550	6,854	(799)	14,605	2,235	16,840
Net income including noncontrolling interests			**2,999**		**2,999**	**121**	**3,120**
Contributions from NRG to Four Brothers and Three Cedars					**—**	**9**	**9**
Issuance of common stock	**17**	**1,302**			**1,302**		**1,302**
Sale of Dominion Energy Midstream common units—net of offering costs					**—**	**18**	**18**
Stock awards (net of change in unearned compensation)		**22**			**22**		**22**
Dividends and distributions			**(1,931)**		**(1,931)**	**(156)**	**(2,087)**
Other comprehensive income, net of tax				**140**	**140**	**1**	**141**
Other		**(9)**	**14**		**5**		**5**
December 31, 2017	**645**	**$9,865**	**$ 7,936**	**$(659)**	**$17,142**	**$2,228**	**$19,370**

(1) See Note 17 for further information.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements

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Dominion Energy, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31,	2017	2016	2015
(millions)			
Operating Activities			
Net income including noncontrolling interests	**$ 3,120**	$ 2,212	$ 1,923
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities:			
Depreciation, depletion and amortization (including nuclear fuel)	**2,202**	1,849	1,669
Deferred income taxes and investment tax credits	**(3)**	725	854
Current income tax for Dominion Energy Questar Pipeline contribution to Dominion Energy Midstream	**—**	(212)	—
Proceeds from assignment of tower rental portfolio	**91**	—	—
Gains on the sales of assets	**(148)**	(50)	(123)
Charges associated with equity method investments	**158**	—	—
Charges associated with future ash pond and landfill closure costs	**—**	197	99
Contribution to pension plan	**(75)**	—	—
Other adjustments	**(37)**	(108)	(42)
Changes in:			
Accounts receivable	**(103)**	(286)	294
Inventories	**15**	1	(26)
Deferred fuel and purchased gas costs, net	**(71)**	54	94
Prepayments	**(62)**	21	(25)
Accounts payable	**(89)**	97	(199)
Accrued interest, payroll and taxes	**64**	203	(52)
Margin deposit assets and liabilities	**(10)**	(66)	237
Net realized and unrealized changes related to derivative activities	**44**	(335)	(176)
Asset retirement obligations	**(94)**	(61)	(4)
Pension and other postretirement benefits	**(177)**	(152)	(51)
Other operating assets and liabilities	**(276)**	38	3
Net cash provided by operating activities	**4,549**	4,127	4,475
Investing Activities			
Plant construction and other property additions (including nuclear fuel)	**(5,504)**	(6,085)	(5,575)
Acquisition of Dominion Energy Questar, net of cash acquired	**—**	(4,381)	—
Acquisition of solar development projects	**(405)**	(40)	(418)
Acquisition of DECG	**—**	—	(497)
Proceeds from sales of securities	**1,831**	1,422	1,340
Purchases of securities	**(1,940)**	(1,504)	(1,326)
Sale of certain retail energy marketing assets	**68**	—	—
Proceeds from assignment of shale development rights	**70**	10	79
Contributions to equity method affiliates	**(370)**	(198)	(51)
Distributions from equity method affiliates	**228**	26	16
Other	**29**	47	(71)
Net cash used in investing activities	**(5,993)**	(10,703)	(6,503)
Financing Activities			
Issuance (repayment) of short-term debt, net	**143**	(654)	734
Issuance of short-term notes	**—**	1,200	600
Repayment and repurchase of short-term notes	**(250)**	(1,800)	(400)
Issuance and remarketing of long-term debt	**3,880**	7,722	2,962
Repayment and repurchase of long-term debt	**(1,572)**	(1,610)	(892)
Net proceeds from issuance of Dominion Energy Midstream common units	**18**	482	—
Net proceeds from issuance of Dominion Energy Midstream preferred units	**—**	490	—
Proceeds from sale of interest in merchant solar projects	**—**	117	184
Contributions from NRG and SunEdison to Four Brothers and Three Cedars	**9**	189	103
Issuance of common stock	**1,302**	2,152	786
Common dividend payments	**(1,931)**	(1,727)	(1,536)
Other	**(296)**	(331)	(224)
Net cash provided by financing activities	**1,303**	6,230	2,317
Increase (decrease) in cash and cash equivalents	**(141)**	(346)	289
Cash and cash equivalents at beginning of year	**261**	607	318
Cash and cash equivalents at end of year	**$ 120**	$ 261	$ 607
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 1,083**	$ 905	$ 843
Income taxes	**9**	145	75
Significant noncash investing and financing activities:(1)(2)			
Accrued capital expenditures	**343**	427	478
Guarantee provided to equity method affiliate	**30**	—	—
Dominion Energy Midstream's acquisition of a noncontrolling partnership interest in Iroquois in exchange for issuance of Dominion Energy Midstream common units	**—**	—	216

(1) See Note 3 for noncash activities related to the acquisition of Four Brothers and Three Cedars.
(2) See Note 17 for noncash activities related to the remarketing of RSNs in 2017 and 2016.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Virginia Electric and Power Company

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries ("Virginia Power") at December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, common shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Virginia Power at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of Virginia Power's management. Our responsibility is to express an opinion on Virginia Power's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Virginia Power in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Virginia Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Virginia Power's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

We have served as Virginia Power's auditor since 1988.

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Virginia Electric and Power Company
Consolidated Statements of Income

Year Ended December 31,	2017	2016	2015
(millions)			
Operating Revenue(1)	**$7,556**	$7,588	$7,622
Operating Expenses			
Electric fuel and other energy-related purchases(1)	**1,909**	1,973	2,320
Purchased electric capacity	**6**	99	330
Other operations and maintenance:			
Affiliated suppliers	**309**	310	279
Other	**1,169**	1,547	1,355
Depreciation and amortization	**1,141**	1,025	953
Other taxes	**290**	284	264
Total operating expenses	**4,824**	5,238	5,501
Income from operations	**2,732**	2,350	2,121
Other income	**76**	56	68
Interest and related charges(1)	**494**	461	443
Income from operations before income tax expense	**2,314**	1,945	1,746
Income tax expense	**774**	727	659
Net Income	**$1,540**	$1,218	$1,087

(1) See Note 24 for amounts attributable to affiliates.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

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Virginia Electric and Power Company
Consolidated Statements of Comprehensive Income

Year Ended December 31,	**2017**	2016	2015
(millions)			
Net income	**$1,540**	$1,218	$1,087
Other comprehensive income (loss), net of taxes:			
Net deferred losses on derivatives-hedging activities, net of $3, $1 and $2 tax	**(5)**	(2)	(1)
Changes in unrealized net gains (losses) on nuclear decommissioning trust funds, net of $(16), $(7) and $1 tax	**24**	11	(4)
Amounts reclassified to net income:			
Net derivative losses on derivative-hedging activities, net of $—, $— and $— tax	**1**	1	1
Net realized gains on nuclear decommissioning trust funds, net of $3, $2 and $4 tax	**(4)**	(4)	(6)
Total other comprehensive income (loss)	**16**	6	(10)
Comprehensive income	**$1,556**	$1,224	$1,077

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

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Virginia Electric and Power Company
Consolidated Balance Sheets

At December 31, (millions)	2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 14**	$ 11
Customer receivables (less allowance for doubtful accounts of $10 at both dates)	**951**	892
Other receivables (less allowance for doubtful accounts of $1 at both dates)	**64**	99
Affiliated receivables	**3**	112
Inventories (average cost method)		
Materials and supplies	**531**	525
Fossil fuel	**319**	328
Prepayments	**27**	30
Regulatory assets	**205**	179
Other(1)	**110**	72
Total current assets	**2,224**	2,248
Investments		
Nuclear decommissioning trust funds	**2,399**	2,106
Other	**3**	3
Total investments	**2,402**	2,109
Property, Plant and Equipment		
Property, plant and equipment	**42,329**	40,030
Accumulated depreciation and amortization	**(13,277)**	(12,436)
Total property, plant and equipment, net	**29,052**	27,594
Deferred Charges and Other Assets		
Pension and other postretirement benefit assets(1)	**199**	130
Intangible assets, net	**233**	225
Regulatory assets	**810**	770
Derivative assets(1)	**91**	128
Other	**128**	104
Total deferred charges and other assets	**1,461**	1,357
Total assets	**$ 35,139**	$ 33,308

(1) See Note 24 for amounts attributable to affiliates.

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At December 31, (millions)	2017	2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	**$ 850**	$ 678
Short-term debt	**542**	65
Accounts payable	**361**	444
Payables to affiliates	**125**	109
Affiliated current borrowings	**33**	262
Accrued interest, payroll and taxes	**256**	239
Asset retirement obligations	**216**	181
Other(1)	**537**	544
Total current liabilities	**2,920**	2,522
Long-Term Debt	**10,496**	9,852
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,728**	5,103
Asset retirement obligations	**1,149**	1,262
Regulatory liabilities	**4,760**	1,962
Pension and other postretirement benefit liabilities(1)	**505**	396
Other	**357**	346
Total deferred credits and other liabilities	**9,499**	9,069
Total liabilities	**22,915**	21,443
Commitments and Contingencies (see Note 22)		
Common Shareholder's Equity		
Common stock – no par(2)	**5,738**	5,738
Other paid-in capital	**1,113**	1,113
Retained earnings	**5,311**	4,968
Accumulated other comprehensive income	**62**	46
Total common shareholder's equity	**12,224**	11,865
Total liabilities and shareholder's equity	**$35,139**	$33,308

(1) See Note 24 for amounts attributable to affiliates.
(2) 500,000 shares authorized; 274,723 shares outstanding at December 31, 2017 and 2016.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

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Virginia Electric and Power Company
Consolidated Statements of Common Shareholder's Equity

(millions, except for shares)	Common Stock Shares (thousands)	Common Stock Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2014	275	$5,738	$1,113	$ 3,154	$ 50	$10,055
Net income				1,087		1,087
Dividends				(491)		(491)
Other comprehensive loss, net of tax					(10)	(10)
Balance at December 31, 2015	275	5,738	1,113	3,750	40	10,641
Net income				1,218		1,218
Other comprehensive income, net of tax					6	6
Balance at December 31, 2016	275	5,738	1,113	4,968	46	11,865
Net income				**1,540**		**1,540**
Dividends				**(1,199)**		**(1,199)**
Other comprehensive income, net of tax					**16**	**16**
Other				**2**		**2**
Balance at December 31, 2017	**275**	**$5,738**	**$1,113**	**$ 5,311**	**$ 62**	**$12,224**

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

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Virginia Electric and Power Company
Consolidated Statements of Cash Flows

Year Ended December 31,	2017	2016	2015
(millions)			
Operating Activities			
Net income	**$ 1,540**	$ 1,218	$ 1,087
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (including nuclear fuel)	**1,333**	1,210	1,121
Deferred income taxes and investment tax credits	**269**	469	251
Proceeds from assignment of rental portfolio	**91**	—	—
Charges associated with future ash pond and landfill closure costs	**—**	197	99
Other adjustments	**(36)**	(16)	(27)
Changes in:			
Accounts receivable	**(27)**	(65)	128
Affiliated accounts receivable and payable	**125**	220	(314)
Inventories	**3**	20	(20)
Prepayments	**3**	8	214
Deferred fuel expenses, net	**(59)**	69	64
Accounts payable	**(42)**	25	(75)
Accrued interest, payroll and taxes	**17**	49	(9)
Net realized and unrealized changes related to derivative activities	**13**	(153)	(67)
Asset retirement obligations	**(88)**	(59)	10
Other operating assets and liabilities	**(181)**	77	93
Net cash provided by operating activities	**2,961**	3,269	2,555
Investing Activities			
Plant construction and other property additions	**(2,496)**	(2,489)	(2,474)
Purchases of nuclear fuel	**(192)**	(153)	(172)
Acquisition of solar development projects	**(41)**	(7)	(43)
Purchases of securities	**(884)**	(775)	(651)
Proceeds from sales of securities	**849**	733	639
Other	**(51)**	(33)	(87)
Net cash used in investing activities	**(2,815)**	(2,724)	(2,788)
Financing Activities			
Issuance (repayment) of short-term debt, net	**477**	(1,591)	295
Repayment of affiliated current borrowings, net	**(229)**	(114)	(51)
Issuance and remarketing of long-term debt	**1,500**	1,688	1,112
Repayment of long-term debt	**(681)**	(517)	(625)
Common dividend payments to parent	**(1,199)**	—	(491)
Other	**(11)**	(18)	(4)
Net cash provided by (used in) financing activities	**(143)**	(552)	236
Increase (decrease) in cash and cash equivalents	**3**	(7)	3
Cash and cash equivalents at beginning of year	**11**	18	15
Cash and cash equivalents at end of year	**$ 14**	$ 11	$ 18
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 458**	$ 435	$ 422
Income taxes	**362**	79	517
Significant noncash investing activities:			
Accrued capital expenditures	**169**	256	169

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Dominion Energy Gas Holdings, LLC

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Dominion Energy Gas Holdings, LLC (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries ("Dominion Energy Gas") at December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Dominion Energy Gas at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of Dominion Energy Gas' management. Our responsibility is to express an opinion on Dominion Energy Gas' consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Dominion Energy Gas in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Dominion Energy Gas is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Dominion Energy Gas' internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

We have served as Dominion Energy Gas' auditor since 2012.

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Dominion Energy Gas Holdings, LLC
Consolidated Statements of Income

Year Ended December 31,	**2017**	2016	2015
(millions)			
Operating Revenue(1)	**$1,814**	$1,638	$1,716
Operating Expenses			
Purchased gas(1)	**132**	109	133
Other energy-related purchases(1)	**21**	12	21
Other operations and maintenance:			
Affiliated suppliers	**87**	81	64
Other(1)	**440**	393	326
Depreciation and amortization	**227**	204	217
Other taxes	**185**	170	166
Total operating expenses	**1,092**	969	927
Income from operations	**722**	669	789
Earnings from equity method investee	**21**	21	23
Other income	**20**	11	1
Interest and related charges(1)	**97**	94	73
Income from operations before income tax expense	**666**	607	740
Income tax expense	**51**	215	283
Net Income	**$ 615**	$ 392	$ 457

(1) See Note 24 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

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Dominion Energy Gas Holdings, LLC
Consolidated Statements of Comprehensive Income

Year Ended December 31,	**2017**	2016	2015
(millions)			
Net income	**$615**	$392	$457
Other comprehensive income (loss), net of taxes:			
Net deferred gains (losses) on derivatives-hedging activities, net of $(3), $10, and $(4) tax	**5**	(16)	6
Changes in unrecognized pension benefit (costs), net of $(8), $14, and $13 tax	**20**	(20)	(20)
Amounts reclassified to net income:			
Net derivative (gains) losses, net of $3, $(6), and $3 tax	**(4)**	9	(3)
Net pension and other postretirement benefit costs, net of $(2), $(2), and $(3) tax	**4**	3	4
Other comprehensive income (loss)	**25**	(24)	(13)
Comprehensive income	**$640**	$368	$444

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

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Dominion Energy Gas Holdings, LLC
Consolidated Balance Sheets

At December 31,	2017	2016
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 4**	$ 23
Customer receivables (less allowance for doubtful accounts of $1 at both dates)(1)	**297**	281
Other receivables (less allowance for doubtful accounts of $1 at both dates)(1)	**15**	13
Affiliated receivables	**10**	17
Inventories:		
Materials and supplies	**55**	57
Gas stored	**9**	13
Prepayments	**112**	94
Gas imbalances(1)	**46**	37
Other	**52**	47
Total current assets	**600**	582
Investments	**97**	99
Property, Plant and Equipment		
Property, plant and equipment	**11,173**	10,475
Accumulated depreciation and amortization	**(3,018)**	(2,851)
Total property, plant and equipment, net	**8,155**	7,624
Deferred Charges and Other Assets		
Goodwill	**542**	542
Intangible assets, net	**109**	98
Regulatory assets	**511**	577
Pension and other postretirement benefit assets(1)	**1,828**	1,557
Other(1)	**98**	63
Total deferred charges and other assets	**3,088**	2,837
Total assets	**$11,940**	$11,142

(1) See Note 24 for amounts attributable to related parties.

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At December 31, (millions)	2017	2016
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term debt	**$ 629**	$ 460
Accounts payable	**193**	221
Payables to affiliates	**62**	29
Affiliated current borrowings	**18**	118
Accrued interest, payroll and taxes	**250**	225
Other(1)	**189**	162
Total current liabilities	**1,341**	1,215
Long-Term Debt	**3,570**	3,528
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**1,454**	2,438
Regulatory liabilities	**1,227**	219
Other(1)	**185**	206
Total deferred credits and other liabilities	**2,866**	2,863
Total liabilities	**7,777**	7,606
Commitments and Contingencies (see Note 22)		
Equity		
Membership interests	**4,261**	3,659
Accumulated other comprehensive loss	**(98)**	(123)
Total equity	**4,163**	3,536
Total liabilities and equity	**$11,940**	$11,142

(1) See Note 24 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

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Dominion Energy Gas Holdings, LLC
Consolidated Statements of Equity

(millions)	Membership Interests	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2014	$3,652	$ (86)	$3,566
Net income	457		457
Distributions	(692)		(692)
Other comprehensive loss, net of tax		(13)	(13)
Balance at December 31, 2015	3,417	(99)	3,318
Net income	392		392
Distributions	(150)		(150)
Other comprehensive loss, net of tax		(24)	(24)
Balance at December 31, 2016	3,659	(123)	3,536
Net income	**615**		**615**
Distributions	**(15)**		**(15)**
Other comprehensive income, net of tax		**25**	**25**
Other	**2**		**2**
Balance at December 31, 2017	**$4,261**	**$ (98)**	**$4,163**

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

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Dominion Energy Gas Holdings, LLC
Consolidated Statements of Cash Flows

Year Ended December 31,	**2017**	2016	2015
(millions)			
Operating Activities			
Net income	**$ 615**	$ 392	$ 457
Adjustments to reconcile net income to net cash provided by operating activities:			
Gains on sales of assets	**(70)**	(50)	(123)
Depreciation and amortization	**227**	204	217
Deferred income taxes and investment tax credits	**27**	238	163
Other adjustments	**(9)**	(6)	16
Changes in:			
Accounts receivable	**(17)**	(68)	115
Affiliated receivables and payables	**40**	88	(105)
Inventories	**6**	8	(13)
Prepayments	**(18)**	(6)	99
Accounts payable	**(17)**	15	(51)
Accrued interest, payroll and taxes	**24**	42	(11)
Pension and other postretirement benefits	**(143)**	(141)	(119)
Other operating assets and liabilities	**(1)**	(68)	(17)
Net cash provided by operating activities	**664**	648	628
Investing Activities			
Plant construction and other property additions	**(778)**	(854)	(795)
Proceeds from sale of equity method investment in Iroquois	**—**	7	—
Proceeds from assignments of shale development rights	**70**	10	79
Other	**(23)**	(18)	(11)
Net cash used in investing activities	**(731)**	(855)	(727)
Financing Activities			
Issuance of short-term debt, net	**169**	69	391
Issuance (repayment) of affiliated current borrowings, net	**(100)**	23	(289)
Repayment of long-term debt	**—**	(400)	—
Issuance of long-term debt	**—**	680	700
Distribution payments to parent	**(15)**	(150)	(692)
Other	**(6)**	(5)	(7)
Net cash provided by financing activities	**48**	217	103
Increase (decrease) in cash and cash equivalents	**(19)**	10	4
Cash and cash equivalents at beginning of year	**23**	13	9
Cash and cash equivalents at end of year	**$ 4**	$ 23	$ 13
Supplemental Cash Flow Information			
Cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 89**	$ 81	$ 70
Income taxes	**9**	(92)	98
Significant noncash investing and financing activities:			
Accrued capital expenditures	**38**	59	57

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

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Combined Notes to Consolidated Financial Statements

NOTE 1. NATURE OF OPERATIONS

Dominion Energy, headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy. Dominion Energy's operations are conducted through various subsidiaries, including Virginia Power and Dominion Energy Gas. Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. Virginia Power is a member of PJM, an RTO, and its electric transmission facilities are integrated into the PJM wholesale electricity markets. All of Virginia Power's stock is owned by Dominion Energy. Dominion Energy Gas is a holding company that conducts business activities through a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, regulated gas transportation and distribution operations in Ohio, and gas gathering and processing activities primarily in West Virginia, Ohio and Pennsylvania. All of Dominion Energy Gas' membership interests are held by Dominion Energy. The Dominion Energy Questar Combination was completed in September 2016. See Note 3 for a description of operations acquired in the Dominion Energy Questar Combination.

Dominion Energy's operations also include the Cove Point LNG import, transport and storage facility in Maryland, an equity investment in Atlantic Coast Pipeline and regulated gas transportation and distribution operations in West Virginia. Dominion Energy's nonregulated operations include merchant generation, energy marketing and price risk management activities, retail energy marketing operations and an equity investment in Blue Racer.

In October 2014, Dominion Energy Midstream launched its initial public offering of 20,125,000 common units representing limited partner interests. At December 31, 2017, Dominion Energy owns the general partner, 50.6% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Energy Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DECG, Dominion Energy Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. The public's ownership interest in Dominion Energy Midstream is reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements.

Dominion Energy manages its daily operations through three primary operating segments: Power Delivery, Power Generation and Gas Infrastructure. Dominion Energy also reports a Corporate and Other segment, which includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Virginia Power manages its daily operations through two primary operating segments: Power Delivery and Power Generation. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Dominion Energy Gas manages its daily operations through one primary operating segment: Gas Infrastructure. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Energy Gas as a result of Dominion Energy's basis in the net assets contributed.

See Note 25 for further discussion of the Companies' operating segments.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

General

The Companies make certain estimates and assumptions in preparing their Consolidated Financial Statements in accordance with GAAP. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses and cash flows for the periods presented. Actual results may differ from those estimates.

The Companies' Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of their respective majority-owned subsidiaries and non-wholly-owned entities in which they have a controlling financial interest. For certain partnership structures, income is allocated based on the liquidation value of the underlying contractual arrangements. NRG's ownership interest in Four Brothers and Three Cedars, as well as Terra Nova Renewable Partners' 33% interest in certain of Dominion Energy's merchant solar projects, is reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements. See Note 3 for further information on these transactions.

The Companies report certain contracts, instruments and investments at fair value. See Note 6 for further information on fair value measurements.

Dominion Energy maintains pension and other postretirement benefit plans. Virginia Power and Dominion Energy Gas participate in certain of these plans. See Note 21 for further information on these plans.

Certain amounts in the 2016 and 2015 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2017 presentation for comparative purposes. The reclassifications did not affect the Companies' net income, total assets, liabilities, equity or cash flows, except for the reclassification of debt issuance costs.

Amounts disclosed for Dominion Energy are inclusive of Virginia Power and/or Dominion Energy Gas, where applicable.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Dominion Energy and Virginia Power collect sales, consumption and consumer utility taxes and Dominion Energy Gas collects sales taxes; however, these amounts are excluded from revenue. Dominion Energy's customer receivables at December 31, 2017 and 2016 included $661 million and $631 million, respectively, of accrued unbilled

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revenue based on estimated amounts of electricity and natural gas delivered but not yet billed to its utility customers. Virginia Power's customer receivables at December 31, 2017 and 2016 included $400 million and $349 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to its customers. Dominion Energy Gas' customer receivables at December 31, 2017 and 2016 included $121 million and $134 million, respectively, of accrued unbilled revenue based on estimated amounts of natural gas delivered but not yet billed to its customers. See Note 9 for amounts attributable to related parties.

The primary types of sales and service activities reported as operating revenue for Dominion Energy are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, and federally-regulated wholesale electric sales and electric transmission services;
- **Nonregulated electric sales** consist primarily of sales of electricity at market-based rates and contracted fixed rates, and associated derivative activity;
- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services and associated derivative activity;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices, sales of gas purchased from third parties, gas trading and marketing revenue and associated derivative activity;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of transmission and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers and sales of gathering services; and
- **Other revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity. Other revenue also includes miscellaneous service revenue from electric and gas distribution operations, sales of energy-related products and services from Dominion Energy's retail energy marketing operations and gas processing and handling revenue.

The primary types of sales and service activities reported as operating revenue for Virginia Power are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric distribution operations and miscellaneous revenue from generation operations, including sales of capacity and other commodities.

The primary types of sales and service activities reported as operating revenue for Dominion Energy Gas are as follows:

- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices and sales of gas purchased from third parties. Revenue from sales of gas production is recognized based on actual volumes of gas sold to purchasers and is reported net of royalties;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of transmission and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers and sales of gathering services;
- **NGL revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity; and
- **Other revenue** consists primarily of miscellaneous service revenue, gas processing and handling revenue.

Electric Fuel, Purchased Energy and Purchased Gas-Deferred Costs

Where permitted by regulatory authorities, the differences between Dominion Energy's and Virginia Power's actual electric fuel and purchased energy expenses and Dominion Energy's and Dominion Energy Gas' purchased gas expenses and the related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery in excess of current period fuel expenses is recognized as a regulatory liability.

Of the cost of fuel used in electric generation and energy purchases to serve utility customers, approximately 84% is currently subject to deferred fuel accounting, while substantially all of the remaining amount is subject to recovery through similar mechanisms.

Virtually all of Dominion Energy Gas', Cove Point's, Questar Gas' and Hope's natural gas purchases are either subject to deferral accounting or are recovered from the customer in the same accounting period as the sale.

Income Taxes

A consolidated federal income tax return is filed for Dominion Energy and its subsidiaries, including Virginia Power and Dominion Energy Gas' subsidiaries. In addition, where applicable, combined income tax returns for Dominion Energy and its subsidiaries are filed in various states; otherwise, separate state income tax returns are filed.

Although Dominion Energy Gas is disregarded for income tax purposes, a provision for income taxes is recognized to reflect the inclusion of its business activities in the tax returns of its parent, Dominion Energy. Virginia Power and Dominion Energy Gas participate in intercompany tax sharing agreements with Dominion Energy and its subsidiaries. Current income taxes are based on taxable income or loss and credits determined on a separate company basis.

Under the agreements, if a subsidiary incurs a tax loss or earns a credit, recognition of current income tax benefits is limited to refunds of prior year taxes obtained by the carryback of the net operating loss or credit or to the extent the tax loss or credit is absorbed by the taxable income of other Dominion Energy consolidated group members. Otherwise, the net operating loss or credit is carried forward and is recognized as a deferred tax asset until realized.

The 2017 Tax Reform Act includes a broad range of tax reform provisions affecting the Companies, including changes in corporate tax rates and business deductions. The 2017 Tax Reform Act reduces the corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. Deferred tax assets and liabilities are classified as noncurrent in the Consolidated Balance

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Sheets and measured at the enacted tax rate expected to apply when temporary differences are realized or settled. Thus, at the date of enactment, federal deferred taxes were remeasured based upon the new 21% tax rate. The total effect of tax rate changes on deferred tax balances is recorded as a component of the income tax provision related to continuing operations for the period in which the law is enacted, even if the assets and liabilities relate to other components of the financial statements, such as items of accumulated other comprehensive income. For Dominion Energy subsidiaries that are not rate-regulated utilities, existing deferred income tax assets or liabilities were adjusted for the reduction in the corporate income tax rate and allocated to continuing operations. Dominion Energy's rate-regulated utility subsidiaries likewise are required to adjust deferred income tax assets and liabilities for the change in income tax rates. However, if it is probable that the effect of the change in income tax rates will be recovered or refunded in future rates, the regulated utility recorded a regulatory asset or liability instead of an increase or decrease to deferred income tax expense.

Accounting for income taxes involves an asset and liability approach. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Accordingly, deferred taxes are recognized for the future consequences of different treatments used for the reporting of transactions in financial accounting and income tax returns. The Companies establish a valuation allowance when it is more-likely-than-not that all, or a portion, of a deferred tax asset will not be realized. Where the treatment of temporary differences is different for rate-regulated operations, a regulatory asset is recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities.

The Companies recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

If it is not more-likely-than-not that a tax position, or some portion thereof, will be sustained, the related tax benefits are not recognized in the financial statements. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of income tax refunds receivable or changes in deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in income taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities. Except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities, noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities on the Consolidated Balance Sheets and current payables are included in accrued interest, payroll and taxes on the Consolidated Balance Sheets.

The Companies recognize interest on underpayments and overpayments of income taxes in interest expense and other income, respectively. Penalties are also recognized in other income.

Dominion Energy and Virginia Power both recognized interest income of $11 million in 2017. Dominion Energy Gas' interest was immaterial in 2017. Interest for the Companies was immaterial in 2016 and 2015. Dominion Energy's, Virginia Power's and Dominion Energy Gas' penalties were immaterial in 2017, 2016 and 2015.

At December 31, 2017, Virginia Power had an income tax-related affiliated payable of $16 million, comprised of $16 million of federal income taxes due to Dominion Energy. Dominion Energy Gas also had an affiliated payable of $25 million due to Dominion Energy, representing $21 million of federal income taxes and $4 million of state income taxes. The net affiliated payables are expected to be paid to Dominion Energy.

In addition, Virginia Power's Consolidated Balance Sheet at December 31, 2017 included $1 million of noncurrent federal income taxes receivable, less than $1 million of state income taxes receivable and $1 million of noncurrent state income taxes receivable. Dominion Energy Gas' Consolidated Balance Sheet at December 31, 2017 included $14 million of state income taxes receivable.

At December 31, 2016, Virginia Power had an income tax-related affiliated receivable of $112 million, comprised of $122 million of federal income taxes due from Dominion Energy net of $10 million for state income taxes due to Dominion Energy. Dominion Energy Gas also had an affiliated receivable of $11 million due from Dominion Energy, representing $10 million of federal income taxes and $1 million of state income taxes. The net affiliated receivables were refunded by Dominion Energy.

In addition, Virginia Power's Consolidated Balance Sheet at December 31, 2016 included $2 million of noncurrent federal income taxes payable, $6 million of state income taxes receivable and $13 million of noncurrent state income taxes receivable. Dominion Energy Gas' Consolidated Balance Sheet at December 31, 2016 included $1 million of noncurrent federal income taxes payable, $1 million of state income taxes receivable and $7 million of noncurrent state income taxes payable.

Investment tax credits are recognized by nonregulated operations in the year qualifying property is placed in service. For regulated operations, investment tax credits are deferred and amortized over the service lives of the properties giving rise to the credits. Production tax credits are recognized as energy is generated and sold.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. The following table illustrates the checks outstanding but not yet presented for payment and recorded in accounts payable for the Companies:

Year Ended December 31,	**2017**	2016
(millions)		
Dominion Energy	**$30**	$24
Virginia Power	**17**	11
Dominion Energy Gas	**7**	9

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The Companies hold restricted cash and cash equivalent balances that primarily consist of amounts held for customer deposits, future debt payments on Dominion Solar Projects III, Inc.'s term loan agreement and a distribution reserve at Cove Point. The amount of restricted cash held at each company is presented in the table below. These balances are presented in Other Current Assets and Other Investments in the Consolidated Balance Sheets.

Year Ended December 31, (millions)	2017	2016
Dominion Energy	**$65**	$61
Virginia Power	**10**	—
Dominion Energy Gas	**26**	20

For purposes of the Consolidated Statements of Cash Flows, cash and cash equivalents include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Derivative Instruments

Dominion Energy uses derivative instruments such as physical and financial forwards, futures, swaps, options and FTRs to manage the commodity, interest rate and foreign currency exchange rate risks of its business operations. Virginia Power uses derivative instruments such as physical and financial forwards, futures, swaps, options and FTRs to manage commodity and interest rate risks. Dominion Energy Gas uses derivative instruments such as physical and financial forwards, futures and swaps to manage commodity, interest rate and foreign currency exchange rate risks.

All derivatives, except those for which an exception applies, are required to be reported in the Consolidated Balance Sheets at fair value. Derivative contracts representing unrealized gain positions and purchased options are reported as derivative assets. Derivative contracts representing unrealized losses and options sold are reported as derivative liabilities. One of the exceptions to fair value accounting, normal purchases and normal sales, may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance.

The Companies do not offset amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. Dominion Energy had margin assets of $92 million and $82 million associated with cash collateral at December 31, 2017 and 2016, respectively. Dominion Energy's margin liabilities associated with cash collateral at December 31, 2017 or 2016 were immaterial. Virginia Power had margin assets of $23 million and $2 million associated with cash collateral at December 31, 2017 and 2016, respectively. Virginia Power's margin liabilities associated with cash collateral were immaterial at December 31, 2017 and 2016. Dominion Energy Gas' margin assets and liabilities associated with cash collateral were immaterial at December 31, 2017 and 2016. See Note 7 for further information about derivatives.

To manage price risk, the Companies hold certain derivative instruments that are not designated as hedges for accounting purposes. However, to the extent the Companies do not hold offsetting positions for such derivatives, they believe these instruments represent economic hedges that mitigate their exposure to fluctuations in commodity prices. All income statement activity, including amounts realized upon settlement, is presented in operating revenue, operating expenses, interest and related charges or other income based on the nature of the underlying risk.

Changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities for jurisdictions subject to cost-based rate regulation. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

DERIVATIVE INSTRUMENTS DESIGNATED AS HEDGING INSTRUMENTS

The Companies designate a portion of their derivative instruments as either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, the Companies formally document the relationship between the hedging instrument and the hedged item, as well as the risk management objective and the strategy for using the hedging instrument. The Companies assess whether the hedging relationship between the derivative and the hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing basis. Any change in the fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, the Companies may elect to exclude certain gains or losses on hedging instruments from the assessment of hedge effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, thus requiring that such changes be recorded currently in earnings. Hedge accounting is discontinued prospectively for derivatives that cease to be highly effective hedges. For derivative instruments that are accounted for as fair value hedges or cash flow hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Cash Flow Hedges-A majority of the Companies' hedge strategies represents cash flow hedges of the variable price risk associated with the purchase and sale of electricity, natural gas and NGLs. The Companies also use interest rate swaps to hedge their exposure to variable interest rates on long-term debt as well as foreign currency swaps to hedge their exposure to interest payments denominated in Euros. For transactions in which the Companies are hedging the variability of cash flows, changes in the fair value of the derivatives are reported in AOCI, to the extent they are effective at offsetting changes in the hedged item. Any derivative gains or losses reported in AOCI are reclassified to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, hedge accounting is discontinued if the occurrence of the forecasted transaction is no longer probable.

Dominion Energy entered into interest rate derivative instruments to hedge its forecasted interest payments related to planned debt issuances in 2014. These interest rate derivatives were designated by Dominion Energy as cash flow hedges prior to the

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formation of Dominion Energy Gas. For the purposes of the Dominion Energy Gas financial statements, the derivative balances, AOCI balance, and any income statement impact related to these interest rate derivative instruments entered into by Dominion Energy have been, and will continue to be, included in the Dominion Energy Gas' Consolidated Financial Statements as the forecasted interest payments related to the debt issuances now occur at Dominion Energy Gas.

Fair Value Hedges-Dominion Energy also uses fair value hedges to mitigate the fixed price exposure inherent in commodity inventory. In addition, Dominion Energy has designated interest rate swaps as fair value hedges on certain fixed rate long-term debt to manage interest rate exposure. For fair value hedge transactions, changes in the fair value of the derivative are generally offset currently in earnings by the recognition of changes in the hedged item's fair value. Hedge accounting is discontinued if the hedged item no longer qualifies for hedge accounting. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives. See Note 7 for further information on derivatives.

Property, Plant and Equipment

Property, plant and equipment is recorded at lower of original cost or fair value, if impaired. Capitalized costs include labor, materials and other direct and indirect costs such as asset retirement costs, capitalized interest and, for certain operations subject to cost-of-service rate regulation, AFUDC and overhead costs. The cost of repairs and maintenance, including minor additions and replacements, is generally charged to expense as it is incurred.

In 2017, 2016 and 2015, Dominion Energy capitalized interest costs and AFUDC to property, plant and equipment of $236 million, $159 million and $100 million, respectively. In 2017, 2016 and 2015, Virginia Power capitalized AFUDC to property, plant and equipment of $37 million, $21 million and $30 million, respectively. In 2017, 2016 and 2015, Dominion Energy Gas capitalized AFUDC to property, plant and equipment of $25 million, $8 million and $1 million, respectively.

Under Virginia law, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset and is not capitalized to property, plant and equipment. In 2017, 2016 and 2015, Virginia Power recorded $22 million, $31 million and $19 million of AFUDC related to these projects, respectively.

For property subject to cost-of-service rate regulation, including Virginia Power electric distribution, electric transmission, and generation property, Dominion Energy Gas natural gas distribution and transmission property, and for certain Dominion Energy natural gas property, the undepreciated cost of such property, less salvage value, is generally charged to accumulated depreciation at retirement. Cost of removal collections from utility customers not representing AROs are recorded as regulatory liabilities. For property subject to cost-of-service rate regulation that will be abandoned significantly before the end of its useful life, the net carrying value is reclassified from plant-in-service when it becomes probable it will be abandoned.

For property that is not subject to cost-of-service rate regulation, including nonutility property, cost of removal not associated with AROs is charged to expense as incurred. The Companies also record gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property's net book value at the retirement date.

Depreciation of property, plant and equipment is computed on the straight-line method based on projected service lives. The Companies' average composite depreciation rates on utility property, plant and equipment are as follows:

Year Ended December 31, (percent)	**2017**	2016	2015
Dominion Energy			
Generation	**2.94**	2.83	2.78
Transmission	**2.55**	2.47	2.42
Distribution	**3.00**	3.02	3.11
Storage	**2.48**	2.29	2.42
Gas gathering and processing	**2.21**	2.66	3.19
General and other	**4.89**	4.12	3.67
Virginia Power			
Generation	**2.94**	2.83	2.78
Transmission	**2.54**	2.36	2.33
Distribution	**3.32**	3.32	3.33
General and other	**4.68**	3.49	3.40
Dominion Energy Gas			
Transmission	**2.40**	2.43	2.46
Distribution	**2.42**	2.55	2.45
Storage	**2.45**	2.19	2.44
Gas gathering and processing	**2.42**	2.58	3.20
General and other	**4.96**	4.54	4.72

In the first quarter of 2017, Virginia Power revised the depreciation rates for its assets to reflect the results of a new depreciation study. This change resulted in an increase in annual depreciation expense of $40 million ($25 million after-tax) for 2017. Additionally, Dominion Energy revised the depreciable lives for its merchant generation assets, excluding Millstone, which resulted in a decrease in annual depreciation expense of $26 million ($16 million after-tax) for 2017.

Capitalized costs of development wells and leaseholds are amortized on a field-by-field basis using the unit-of-production method and the estimated proved developed or total proved gas and oil reserves, at a rate of $2.11 per mcfe in 2017.

Dominion Energy's nonutility property, plant and equipment is depreciated using the straight-line method over the following estimated useful lives:

Asset	Estimated Useful Lives
Merchant generation-nuclear	**44 years**
Merchant generation-other	**15-40 years**
Nonutility gas gathering and processing	**3-50 years**
General and other	**5-59 years**

Depreciation and amortization related to Virginia Power's and Dominion Energy Gas' nonutility property, plant and equipment and exploration and production properties was immaterial for the years ended December 31, 2017, 2016 and 2015, except for Dominion Energy Gas' nonutility gas gathering and processing properties which are depreciated using the straight-line method over estimated useful lives between 10 and 50 years.

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Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis. Dominion Energy and Virginia Power report the amortization of nuclear fuel in electric fuel and other energy-related purchases expense in their Consolidated Statements of Income and in depreciation and amortization in their Consolidated Statements of Cash Flows.

Long-Lived and Intangible Assets

The Companies perform an evaluation for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets or intangible assets with finite lives may not be recoverable. A long-lived or intangible asset is written down to fair value if the sum of its expected future undiscounted cash flows is less than its carrying amount. Intangible assets with finite lives are amortized over their estimated useful lives.

Regulatory Assets and Liabilities

The accounting for Dominion Energy's and Dominion Energy Gas' regulated gas and Virginia Power's regulated electric operations differs from the accounting for nonregulated operations in that they are required to reflect the effect of rate regulation in their Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator.

The Companies evaluate whether or not recovery of their regulatory assets through future rates is probable and make various assumptions in their analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions, legislation or historical experience, as well as discussions with applicable regulatory authorities and legal counsel. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made.

Asset Retirement Obligations

The Companies recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed, for which a legal obligation exists. These amounts are generally capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, fair value is estimated using discounted cash flow analyses. Quarterly, the Companies assess their AROs to determine if circumstances indicate that estimates of the amounts or timing of future cash flows associated with retirement activities have changed. AROs are adjusted when significant changes in the amounts or timing of future cash flows are identified. Dominion Energy and Dominion Energy Gas report accretion of AROs and depreciation on asset retirement costs associated with their natural gas pipeline and storage well assets as an adjustment to the related regulatory liabilities when revenue is recoverable from customers for AROs. Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with decommissioning its nuclear power stations as an adjustment to the regulatory liability for certain jurisdictions. Additionally, Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with certain rider and prospective rider projects as an adjustment to the regulatory asset for certain jurisdictions. Accretion of all other AROs and depreciation of all other asset retirement costs are reported in other operations and maintenance expense and depreciation expense, respectively, in the Consolidated Statements of Income.

Debt Issuance Costs

The Companies defer and amortize debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. Deferred debt issuance costs are recorded as a reduction in long-term debt in the Consolidated Balance Sheets. Amortization of the issuance costs is reported as interest expense. Unamortized costs associated with redemptions of debt securities prior to stated maturity dates are generally recognized and recorded in interest expense immediately. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation are deferred and amortized over the lives of the new issuances.

Investments

Marketable Equity and Debt Securities

Dominion Energy accounts for and classifies investments in marketable equity and debt securities as trading or available-for-sale securities. Virginia Power classifies investments in marketable equity and debt securities as available-for-sale securities.

- *Trading securities* include marketable equity and debt securities held by Dominion Energy in rabbi trusts associated with certain deferred compensation plans. These securities are reported in other investments in the Consolidated Balance Sheets at fair value with net realized and unrealized gains and losses included in other income in the Consolidated Statements of Income.
- *Available-for-sale securities* include all other marketable equity and debt securities, primarily comprised of securities held in the nuclear decommissioning trusts. These investments are reported at fair value in nuclear decommissioning trust funds in the Consolidated Balance Sheets. Net realized and unrealized gains and losses (including any other-than-temporary impairments) on investments held in Virginia Power's nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. For all other available-for-sale securities, including those held in Dominion Energy's merchant generation nuclear decommissioning trusts, net realized gains and losses (including any other-than-temporary impairments) are included in other income and unrealized gains and losses are reported as a component of AOCI, after-tax.

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In determining realized gains and losses for marketable equity and debt securities, the cost basis of the security is based on the specific identification method.

NON-MARKETABLE INVESTMENTS

The Companies account for illiquid and privately held securities for which market prices or quotations are not readily available under either the equity or cost method. Non-marketable investments include:

- *Equity method investments* when the Companies have the ability to exercise significant influence, but not control, over the investee. Dominion Energy's investments are included in investments in equity method affiliates and Virginia Power's investments are included in other investments in their Consolidated Balance Sheets. The Companies record equity method adjustments in other income in the Consolidated Statements of Income including: their proportionate share of investee income or loss, gains or losses resulting from investee capital transactions, amortization of certain differences between the carrying value and the equity in the net assets of the investee at the date of investment and other adjustments required by the equity method.
- *Cost method investments* when Dominion Energy and Virginia Power do not have the ability to exercise significant influence over the investee. Dominion Energy's and Virginia Power's investments are included in other investments and nuclear decommissioning trust funds.

OTHER-THAN-TEMPORARY IMPAIRMENT

The Companies periodically review their investments to determine whether a decline in fair value should be considered other-than-temporary. If a decline in fair value of any security is determined to be other-than-temporary, the security is written down to its fair value at the end of the reporting period.

Decommissioning Trust Investments—Special Considerations

- The recognition provisions of the FASB's other-than-temporary impairment guidance apply only to debt securities classified as available-for-sale or held-to-maturity, while the presentation and disclosure requirements apply to both debt and equity securities.
- *Debt Securities*—Using information obtained from their nuclear decommissioning trust fixed-income investment managers, Dominion Energy and Virginia Power record in earnings any unrealized loss for a debt security when the manager intends to sell the debt security or it is more-likely-than-not that the manager will have to sell the debt security before recovery of its fair value up to its cost basis. If that is not the case, but the debt security is deemed to have experienced a credit loss, Dominion Energy and Virginia Power record the credit loss in earnings and any remaining portion of the unrealized loss in AOCI. Credit losses are evaluated primarily by considering the credit ratings of the issuer, prior instances of non-performance by the issuer and other factors.
- *Equity securities and other investments*—Dominion Energy's and Virginia Power's method of assessing other-than-temporary declines requires demonstrating the ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value prior to the consideration of the other criteria mentioned above. Since Dominion Energy and Virginia Power have limited ability to oversee the day-to-day management of nuclear decommissioning trust fund investments, they do not have the ability to ensure investments are held through an anticipated recovery period. Accordingly, they consider all equity and other securities as well as non-marketable investments held in nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired.

Inventories

Materials and supplies and fossil fuel inventories are valued primarily using the weighted-average cost method. Stored gas inventory is valued using the weighted-average cost method, except for East Ohio gas distribution operations, which are valued using the LIFO method. Under the LIFO method, current stored gas inventory was valued at $9 million and $13 million at December 31, 2017 and December 31, 2016, respectively. Based on the average price of gas purchased during 2017 and 2016, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by $79 million and $55 million, respectively.

Gas Imbalances

Natural gas imbalances occur when the physical amount of natural gas delivered from, or received by, a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. Dominion Energy and Dominion Energy Gas value these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to Dominion Energy from other parties are reported in other current assets and imbalances that Dominion Energy and Dominion Energy Gas owe to other parties are reported in other current liabilities in the Consolidated Balance Sheets.

Goodwill

Dominion Energy and Dominion Energy Gas evaluate goodwill for impairment annually as of April 1 and whenever an event occurs or circumstances change in the interim that would more-likely-than-not reduce the fair value of a reporting unit below its carrying amount.

New Accounting Standards

REVENUE RECOGNITION

In May 2014, the FASB issued revised accounting guidance for revenue recognition from contracts with customers. The core principle of this revised accounting guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this update also require disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For the Companies, the revised accounting guidance is effective for interim and annual periods beginning January 1, 2018. The Companies have completed their evaluations of the impact of this guidance and expect no significant impact on their results of

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operations. However, the Companies will have offsetting increases in operating revenues and other energy-related purchases for noncash consideration related to NGLs received in consideration for performing processing and fractionation services and offsetting decreases in operating revenues and purchased gas for fuel retained to offset costs on certain transportation and storage arrangements. The Companies will apply the standard using the modified retrospective method as opposed to the full retrospective method.

FINANCIAL INSTRUMENTS

In January 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of financial instruments. In accordance with the guidance effective January 2018, Dominion Energy and Virginia Power will no longer classify equity securities as trading or available-for-sale securities. All equity securities with a readily determinable fair value, or for which it is permitted to estimate fair value using NAV (or its equivalent), including those held in Dominion Energy's and Virginia Power's nuclear decommissioning trusts and Dominion Energy's rabbi trusts, will be reported at fair value in nuclear decommissioning trust funds and other investments, respectively, in the Consolidated Balance Sheets. However, Dominion Energy and Virginia Power may elect a measurement alternative for equity securities without a readily determinable fair value. Under the measurement alternative, equity securities will be reported at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or a similar investment of the same issuer. Net realized and unrealized gains and losses on equity securities held in Virginia Power's nuclear decommissioning trusts will be recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. For all other equity securities, including those held in Dominion Energy's merchant generation nuclear decommissioning trusts and rabbi trusts, net realized and unrealized gains and losses will be included in other income. Dominion Energy and Virginia Power will qualitatively assess equity securities reported using the measurement alternative to evaluate whether the investment is impaired on an ongoing basis.

Upon adoption of this guidance for equity securities held at January 1, 2018, Dominion Energy and Virginia Power recorded the cumulative-effect of a change in accounting principle to reclassify net unrealized gains from AOCI to retained earnings and to recognize equity securities previously categorized as cost method investments at fair value in nuclear decommissioning trust funds in the Consolidated Balance Sheets and a cumulative-effect adjustment to retained earnings. Dominion Energy and Virginia Power reclassified approximately $1.1 billion ($734 million after-tax) and $119 million ($73 million after-tax), respectively, of net unrealized gains from AOCI to retained earnings. Dominion Energy and Virginia Power also recorded approximately $36 million ($22 million after-tax) in net unrealized gains on equity securities previously classified as cost method investments of which $4 million was recorded to retained earnings and $32 million was recorded to regulatory liabilities for net unrealized gains subject to cost-based regulation. The potential impact to the Consolidated Statements of Income is subject to investment price risk and is therefore difficult to reasonably estimate. If this guidance had been effective January 1, 2017, Dominion Energy and Virginia Power would have recorded net unrealized gains of approximately $275 million ($176 million after-tax) and $30 million ($19 million after-tax), respectively, to other income in the Consolidated Statements of Income.

LEASES

In February 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. The update requires that a liability and corresponding right-of-use asset are recorded on the balance sheet for all leases, including those leases currently classified as operating leases, while also refining the definition of a lease. In addition lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. Lessor accounting remains largely unchanged.

The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented for leases that commenced prior to the date of adoption. The Companies plan to elect the proposed transition expedient which would allow the Companies to maintain historical presentation for periods before January 1, 2019. The Companies expect to elect the other practical expedients, which would require no reassessment of whether existing contracts are or contain leases and no reassessment of lease classification for existing leases. The Companies have completed a preliminary assessment for evaluating the impact of this guidance and anticipate that its adoption will result in a significant amount of offsetting right-of-use assets and liabilities on their financial position for leases in effect at the adoption date. No material changes are expected on the Companies' results of operations. The Companies are beginning implementation activities that primarily include accumulating contracts and lease data points in formats compatible with a new lease management system that will assist with the initial adoption and on-going compliance with the standard.

DEFINITION OF A BUSINESS

In January 2017, the FASB issued revised accounting guidance to clarify the definition of a business. The revised guidance affects the evaluation of whether a transaction should be accounted for as an acquisition or disposition of an asset or a business, which may impact goodwill and related financial statement disclosures. The Companies have adopted this guidance on a prospective basis effective October 1, 2017. The adoption of the pronouncement will result in additional transactions being accounted for as asset acquisitions or dispositions.

DERECOGNITION AND PARTIAL SALES OF NONFINANCIAL ASSETS

In February 2017, the FASB issued revised accounting guidance clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2018, and the Companies have elected to apply the standard using the modified retrospective method. Upon adoption of the standard on January 1, 2018,

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Dominion Energy recorded the cumulative-effect of a change in accounting principle to reclassify $127 million from noncontrolling interests to common stock related to the sale of a noncontrolling interest in certain merchant solar projects completed in December 2015 and January 2016.

NET PERIODIC PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

In March 2017, the FASB issued revised accounting guidance for the presentation of net periodic pension and other postretirement benefit costs. The update requires that the service cost component of net periodic pension and other postretirement benefit costs be classified in the same line item as other compensation costs arising from services rendered by employees, while all other components of net periodic pension and other postretirement benefit costs would be classified outside of income from operations. In addition, only the service cost component will be eligible for capitalization during construction. However, these changes will not impact the accounting by participants in a multi-employer plan. The standard also recognized that in the event that a regulator continues to require capitalization of all net periodic benefit costs prospectively, the difference would result in recognition of a regulatory asset or liability. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2018, with a retrospective adoption for income statement presentation and a prospective adoption for capitalization. For costs not capitalized for which regulators are expected to provide recovery, a regulatory asset will be established. As such, the amounts eligible for capitalization in the Consolidated Financial Statements of Virginia Power and Dominion Energy Gas, as subsidiary participants in Dominion Energy's multi-employer plans will differ from the amounts eligible for capitalization in the Consolidated Financial Statements of Dominion Energy, the plan administrator. These differences will result in a regulatory asset or liability recorded in the Consolidated Financial Statements of Dominion Energy.

TAX REFORM

In December 2017, the staff of the SEC issued guidance which clarifies accounting for income taxes if information is not yet available or complete and provides for up to a one-year measurement period in which to complete the required analyses and accounting. The guidance describes three scenarios associated with a company's status of accounting for income tax reform: (1) a company is complete with its accounting for certain effects of tax reform, (2) a company is able to determine a reasonable estimate for certain effects of tax reform and records that estimate as a provisional amount, or (3) a company is not able to determine a reasonable estimate and therefore continues to apply accounting for income taxes based on the provisions of the tax laws that were in effect immediately prior to the 2017 Tax Reform Act being enacted. In addition, the guidance provides clarification related to disclosures for entities which are utilizing the measurement period. The Companies have recorded their best estimate of the impacts of the 2017 Tax Reform Act as discussed above and in Note 5. The amounts are considered to be provisional and may result in adjustments to be recognized during the measurement period.

In February 2018, the FASB issued revised accounting guidance to provide clarification on the application of the 2017 Tax Reform Act for balances recorded within AOCI. The revised guidance provides for stranded amounts within AOCI from the impacts of the 2017 Tax Reform Act to be reclassified to retained earnings. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2019, with early adoption permitted, and may be applied prospectively or retrospectively upon adoption. If the Companies had adopted this guidance for the period ended December 31, 2017, Dominion Energy would have reclassified a benefit of $165 million from AOCI to retained earnings, Dominion Energy Gas would have reclassified a benefit of $26 million from AOCI to membership interests and Virginia Power would have reclassified an expense of $13 million from AOCI to retained earnings.

NOTE 3. ACQUISITIONS AND DISPOSITIONS

DOMINION ENERGY

Proposed Acquisition of SCANA

Under the terms of the SCANA Merger Agreement announced in January 2018, Dominion Energy has agreed to issue 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock upon closing. In addition, Dominion Energy will provide the financial support for SCE&G to make a $1.3 billion up-front, one-time rate credit to all current electric service customers of SCE&G to be paid within 90 days of closing and a $575 million refund along with the benefit of the 2017 Tax Reform Act resulting in at least a 5% reduction to SCE&G electric service customers' bills over an eight-year period as well as the exclusions from rate recovery of approximately $1.7 billion of costs related to the V.C. Summer Units 2 and 3 new nuclear development project and approximately $180 million to purchase the Columbia Energy Center power station. In addition, SCANA's debt, which currently totals approximately $7.0 billion, is expected to remain outstanding.

The transaction requires approval of SCANA's shareholders, FERC and the NRC and clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act. In February 2018, the Federal Trade Commission granted early termination of the waiting period under the Hart-Scott-Rodino Act. In January 2018, SCANA and Dominion Energy filed for review and approval, as required, from the South Carolina Commission, the North Carolina Commission, the Georgia Public Service Commission and the NRC. Dominion Energy is not required to accept an order by the South Carolina Commission approving Dominion Energy's merger with SCANA if such order contains any material change to the terms, conditions or undertakings set forth in the cost recovery plan related to the V.C. Summer Units 2 and 3 new nuclear development project or any significant changes to the economic value of the cost recovery plan. In addition, the SCANA Merger Agreement provides that Dominion Energy will have the right to refuse to close the merger if there shall have occurred any substantive change in the Base Load Review Act or other laws governing South Carolina public utilities which has or would reasonably be expected to have an adverse effect on SCE&G. The SCANA Merger Agreement con-

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tains certain termination rights for both Dominion Energy and SCANA, and provides that, upon termination of the SCANA Combination under specified circumstances, Dominion Energy would be required to pay a termination fee of $280 million to SCANA and SCANA would be required to pay Dominion Energy a termination fee of $240 million. Subject to receipt of SCANA shareholder and any required regulatory approvals and meeting closing conditions, Dominion Energy targets closing by the end of 2018.

Acquisition of Dominion Energy Questar

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination and Dominion Energy Questar, a Rockies-based integrated natural gas company, became a wholly-owned subsidiary of Dominion Energy. Dominion Energy Questar included Questar Gas, Wexpro and Dominion Energy Questar Pipeline at closing. Questar Gas has regulated gas distribution operations in Utah, southwestern Wyoming and southeastern Idaho. Wexpro develops and produces natural gas from reserves supplied to Questar Gas under a cost-of-service framework. Dominion Energy Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage services in Utah, Wyoming and western Colorado. The Dominion Energy Questar Combination provides Dominion Energy with pipeline infrastructure that provides a principal source of gas supply to Western states. Dominion Energy Questar's regulated businesses also provide further balance between Dominion Energy's electric and gas operations.

In accordance with the terms of the Dominion Energy Questar Combination, at closing, each share of issued and outstanding Dominion Energy Questar common stock was converted into the right to receive $25.00 per share in cash. The total consideration was $4.4 billion based on 175.5 million shares of Dominion Energy Questar outstanding at closing.

Dominion Energy financed the Dominion Energy Questar Combination through the: (1) August 2016 issuance of $1.4 billion of 2016 Equity Units, (2) August 2016 issuance of $1.3 billion of senior notes, (3) September 2016 borrowing of $1.2 billion under a term loan agreement and (4) $500 million of the proceeds from the April 2016 issuance of common stock. See Notes 17 and 19 for more information.

Purchase Price Allocation

Dominion Energy Questar's assets acquired and liabilities assumed were measured at estimated fair value at the closing date and are included in the Gas Infrastructure operating segment. The majority of operations acquired are subject to the rate-setting authority of FERC, as well as the Utah Commission and/or the Wyoming Commission and therefore are accounted for pursuant to ASC 980, *Regulated Operations*. The fair values of Dominion Energy Questar's assets and liabilities subject to rate-setting and cost recovery provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair values of these assets and liabilities equal their carrying values. Accordingly, neither the assets and liabilities acquired, nor the pro forma financial information, reflect any adjustments related to these amounts.

The fair value of Dominion Energy Questar's assets acquired and liabilities assumed that are not subject to the rate-setting provisions discussed above was determined using the income approach. In addition, the fair value of Dominion Energy Questar's 50% interest in White River Hub, accounted for under the equity method, was determined using the market approach and income approach. The valuations are considered Level 3 fair value measurements due to the use of significant judgmental and unobservable inputs, including projected timing and amount of future cash flows and discount rates reflecting risk inherent in the future cash flows and future market prices.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the closing date. The goodwill reflects the value associated with enhancing Dominion Energy's regulated portfolio of businesses, including the expected increase in demand for low-carbon, natural gas-fired generation in the Western states and the expected continued growth of rate-regulated businesses located in a defined service area with a stable regulatory environment. The goodwill recognized is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to goodwill.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at closing which reflects the following adjustments from the preliminary valuation recognized during the measurement period. During the fourth quarter of 2016, certain modifications were made to preliminary valuation amounts for acquired property, plant and equipment, current liabilities, and deferred income taxes, resulting in a $6 million net decrease to goodwill, which related primarily to the sale of Questar Fueling Company in December 2016 as further described in the *Sale of Questar Fueling Company*. In the third quarter of 2017, certain modifications were made to the valuation amounts for regulatory liabilities, current liabilities and deferred income taxes, resulting in a $6 million net increase to goodwill recorded in Dominion Energy's Consolidated Balance Sheets. The modifications relate primarily to the finalization of Dominion Energy Questar's 2016 tax return for the period January 1, 2016 through the Dominion Energy Questar Combination, as well as certain regulatory adjustments.

(millions)	Amount
Total current assets	$ 224
Investments(1)	58
Property, plant and equipment(2)	4,131
Goodwill	3,111
Total deferred charges and other assets, excluding goodwill	75
Total Assets	7,599
Total current liabilities(3)	793
Long-term debt(4)	963
Deferred income taxes	807
Regulatory liabilities	259
Asset retirement obligations	160
Other deferred credits and other liabilities	220
Total Liabilities	3,202
Total purchase price	4,397

(1) Includes $40 million for an equity method investment in White River Hub. The fair value adjustment on the equity method investment in White River Hub is considered to be equity method goodwill and is not amortized.

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(2) Nonregulated property, plant and equipment, excluding land, will be depreciated over remaining useful lives primarily ranging from 9 to 18 years.
(3) Includes $301 million of short-term debt, of which no amounts remain outstanding at December 31, 2017, as well as a $250 million variable interest rate term loan due in August 2017 that was paid in July 2017.
(4) Unsecured senior and medium-term notes with maturities which range from 2017 to 2048 and bear interest at rates from 2.98% to 7.20%.

REGULATORY MATTERS

The transaction required approval of Dominion Energy Questar's shareholders, clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act and approval from both the Utah Commission and the Wyoming Commission. In February 2016, the Federal Trade Commission granted antitrust approval of the Dominion Energy Questar Combination under the Hart-Scott-Rodino Act. In May 2016, Dominion Energy Questar's shareholders voted to approve the Dominion Energy Questar Combination. In August 2016 and September 2016, approvals were granted by the Utah Commission and the Wyoming Commission, respectively. Information regarding the transaction was also provided to the Idaho Commission, who acknowledged the Dominion Energy Questar Combination in October 2016, and directed Dominion Energy Questar to notify the Idaho Commission when it makes filings with the Utah Commission.

With the approval of the Dominion Energy Questar Combination in Utah and Wyoming, Dominion Energy agreed to the following:

- Contribution of $75 million to Dominion Energy Questar's qualified and non-qualified defined-benefit pension plans and its other post-employment benefit plans within six months of the closing date. This contribution was made in January 2017.
- Increasing Dominion Energy Questar's historical level of corporate contributions to charities by $1 million per year for at least five years.
- Withdrawal of Questar Gas' general rate case filed in July 2016 with the Utah Commission and agreement to not file a general rate case with the Utah Commission to adjust its base distribution non-gas rates prior to July 2019, unless otherwise ordered by the Utah Commission. In addition, Questar Gas agreed not to file a general rate case with the Wyoming Commission with a requested rate effective date earlier than January 2020. Questar Gas' ability to adjust rates through various riders is not affected.

RESULTS OF OPERATIONS AND PRO FORMA INFORMATION

The impact of the Dominion Energy Questar Combination on Dominion Energy's operating revenue and net income attributable to Dominion Energy in the Consolidated Statements of Income for the twelve months ended December 31, 2016 was an increase of $379 million and $73 million, respectively.

Dominion Energy incurred transaction and transition costs in 2017 and 2016, of which $26 million and $58 million was recorded in other operations and maintenance expense, respectively, and $16 million was recorded in interest and related charges in 2016 in Dominion Energy's Consolidated Statements of Income. These costs consist of the amortization of financing costs, the charitable contribution commitment described above, employee-related expenses, professional fees, and other miscellaneous costs.

The following unaudited pro forma financial information reflects the consolidated results of operations of Dominion Energy assuming the Dominion Energy Questar Combination had taken place on January 1, 2015. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of the combined company.

	Twelve Months Ended December 31,	
	2016(1)	2015
(millions, except EPS)		
Operating Revenue	$12,497	$12,818
Net income attributable to Dominion Energy	2,300	2,108
Earnings Per Common Share – Basic	$ 3.73	$ 3.56
Earnings Per Common Share – Diluted	$ 3.73	$ 3.55

(1) Amounts include adjustments for non-recurring costs directly related to the Dominion Energy Questar Combination.

CONTRIBUTION OF DOMINION ENERGY QUESTAR PIPELINE TO DOMINION ENERGY MIDSTREAM

In October 2016, Dominion Energy entered into the Contribution Agreement under which Dominion Energy contributed Dominion Energy Questar Pipeline to Dominion Energy Midstream. Upon closing of the agreement on December 1, 2016, Dominion Energy Midstream became the owner of all of the issued and outstanding membership interests of Dominion Energy Questar Pipeline in exchange for consideration consisting of Dominion Energy Midstream common and convertible preferred units with a combined value of $467 million and cash payment of $823 million, $300 million of which is considered a debt-financed distribution, for a total of $1.3 billion. In addition, under the terms of the Contribution Agreement, Dominion Energy Midstream repurchased 6,656,839 common units from Dominion Energy, and repaid its $301 million promissory note to Dominion Energy in December 2016. The cash proceeds from these transactions were utilized in December 2016 to repay the $1.2 billion term loan agreement borrowed in September 2016. Since Dominion Energy consolidates Dominion Energy Midstream for financial reporting purposes, the transactions associated with the Contribution Agreement were eliminated upon consolidation. See Note 5 for the tax impacts of the transactions.

SALE OF QUESTAR FUELING COMPANY

In December 2016, Dominion Energy completed the sale of Questar Fueling Company. The proceeds from the sale were $28 million, net of transaction costs. No gain or loss was recorded in Dominion Energy's Consolidated Statements of Income, as the sale resulted in measurement period adjustments to the net assets acquired of Dominion Energy Questar. See the *Purchase Price Allocation* section above for additional details on the measurement period adjustments recorded.

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Wholly-Owned Merchant Solar Projects

ACQUISITIONS

The following table presents significant completed acquisitions of wholly-owned merchant solar projects by Dominion Energy.

Completed Acquisition Date	Seller	Number of Projects	Project Location	Project Name(s)	Initial Acquisition (millions)(1)	Project Cost (millions)(2)	Date of Commercial Operations	MW Capacity
April 2015	EC&R NA Solar PV, LLC	1	California	Alamo	$ 66	$ 66	May 2015	20
April 2015	EDF Renewable Development, Inc.	3	California	Cottonwood(3)	106	106	May 2015	24
June 2015	EDF Renewable Development, Inc.	1	California	Catalina 2	68	68	July 2015	18
July 2015	SunPeak Solar, LLC	1	California	Imperial Valley 2	42	71	August 2015	20
November 2015	EC&R NA Solar PV, LLC	1	California	Maricopa West	65	65	December 2015	20
November 2015	Community Energy Solar, LLC	1	Virginia	Amazon Solar Farm U.S East	34	212	October 2016	80
February 2017	Community Energy Solar, LLC	1	Virginia	Amazon Solar Farm Virginia—Southampton	29	205	December 2017	100
March 2017	Solar Frontier Americas Holding LLC	1(4)	California	Midway II	77	78	June 2017	30
May 2017	Cypress Creek Renewables, LLC	1	North Carolina	IS37	154	160	June 2017	79
June 2017	Hecate Energy Virginia C&C LLC	1	Virginia	Clarke County	16	16	August 2017	10
June 2017	Strata Solar Development, LLC/Moorings Farm 2 Holdco, LLC	2	North Carolina	Fremont, Moorings 2	20	20	November 2017	10
September 2017	Hecate Energy Virginia C&C LLC	1	Virginia	Cherrydale	40	41	November 2017	20
October 2017	Strata Solar Development, LLC	2	North Carolina	Clipperton, Pikeville	20	21	November 2017	10

(1) The purchase price was primarily allocated to Property, Plant and Equipment.
(2) Includes acquisition cost.
(3) One of the projects, Marin Carport, began commercial operations in 2016.
(4) In April 2017, Dominion Energy discontinued efforts on the acquisition of the additional 20 MW solar project from Solar Frontier Americas Holding LLC.

In addition during 2016, Dominion Energy acquired 100% of the equity interests of seven solar projects in Virginia, North Carolina and South Carolina for an aggregate purchase price of $32 million, all of which was allocated to property, plant and equipment. The projects cost $421 million in total, including initial acquisition costs, and generate 221 MW combined. One of the projects commenced commercial operations in 2016 and the remaining projects commenced commercial operations in 2017.

Long-term power purchase, interconnection and operation and maintenance agreements have been executed for all of the projects described above. These projects are included in the Power Generation operating segment. Dominion Energy has claimed or will claim federal investment tax credits on these solar projects.

SALE OF INTEREST IN MERCHANT SOLAR PROJECTS

In September 2015, Dominion Energy signed an agreement to sell a noncontrolling interest (consisting of 33% of the equity interests) in all of its then-currently wholly-owned merchant solar projects, 24 solar projects totaling 425 MW, to SunEdison, including certain projects in the table above. In December 2015, the sale of interest in 15 of the solar projects closed for $184 million with the sale of interest in the remaining projects completed in January 2016 for $117 million. Upon closing, SunEdison sold its interest in these projects to Terra Nova Renewable Partners. Terra Nova Renewable Partners has a future option to buy all or a portion of Dominion Energy's remaining 67% ownership in the projects upon the occurrence of certain events, none of which are expected to occur in 2018.

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Non-Wholly-Owned Merchant Solar Projects

ACQUISITIONS OF FOUR BROTHERS AND THREE CEDARS

In June 2015, Dominion Energy acquired 50% of the units in Four Brothers from SunEdison for $64 million of consideration, consisting of $2 million in cash and a $62 million payable. Dominion Energy had no remaining obligation related to this payable at December 31, 2016. Four Brothers operates four solar projects located in Utah, which produce and sell electricity and renewable energy credits. The facilities began commercial operations during the third quarter of 2016, generating 320 MW, at a cost of approximately $670 million.

In September 2015, Dominion Energy acquired 50% of the units in Three Cedars from SunEdison for $43 million of consideration, consisting of $6 million in cash and a $37 million payable. There was a $2 million payable included in other current liabilities in Dominion Energy's Consolidated Balance Sheets at December 31, 2016. Dominion has no remaining obligation related to this payable at December 31, 2017. Three Cedars operates three solar projects located in Utah, which produce and sell electricity and renewable energy credits. The facilities began commercial operations during the third quarter of 2016, generating 210 MW, at a cost of approximately $450 million.

The Four Brothers and Three Cedars facilities operate under long-term power purchase, interconnection and operation and maintenance agreements. Dominion Energy claimed 99% of the federal investment tax credits on the projects.

Dominion Energy owns 50% of the voting interests in Four Brothers and Three Cedars and has a controlling financial interest over the entities through its rights to control operations. The allocation of the $64 million purchase price for Four Brothers resulted in $89 million of property, plant and equipment and $25 million of noncontrolling interest. The allocation of the $43 million purchase price for Three Cedars resulted in $65 million of property, plant and equipment and $22 million of noncontrolling interest. The noncontrolling interest for each entity was measured at fair value using the discounted cash flow method, with the primary components of the valuation being future cash flows (both incoming and outgoing) and the discount rate. Dominion Energy determined its discount rate based on the cost of capital a utility-scale investor would expect, as well as the cost of capital an individual project developer could achieve via a combination of nonrecourse project financing and outside equity partners. The acquired assets of Four Brothers and Three Cedars are included in the Power Generation operating segment.

Dominion Energy has assumed the majority of the agreements to provide administrative and support services in connection with operations and maintenance of the facilities and technical management services of the solar facilities. Costs related to services to be provided under these agreements were immaterial for the years ended December 31, 2017, 2016 and 2015.

In November 2016, NRG acquired the 50% of units in Four Brothers and Three Cedars previously held by SunEdison. Subsequent to Dominion Energy's acquisition of Four Brothers and Three Cedars, SunEdison and NRG made contributions to Four Brothers and Three Cedars of $301 million in aggregate through December 31, 2017, which are reflected as noncontrolling interests in the Consolidated Balance Sheets.

Dominion Energy Midstream Acquisition of Interest in Iroquois

In September 2015, Dominion Energy Midstream acquired from NG and NJNR a 25.93% noncontrolling partnership interest in Iroquois, which owns and operates a 416-mile, FERC-regulated natural gas transmission pipeline in New York and Connecticut. In exchange for this partnership interest, Dominion Energy Midstream issued 8.6 million common units representing limited partnership interests in Dominion Energy Midstream (6.8 million common units to NG for its 20.4% interest and 1.8 million common units to NJNR for its 5.53% interest). The investment was recorded at $216 million based on the value of Dominion Energy Midstream's common units at closing. These common units are reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements. Dominion Energy Midstream's noncontrolling partnership interest is reflected in the Gas Infrastructure operating segment. In addition to this acquisition, Dominion Energy Gas currently holds a 24.07% noncontrolling partnership interest in Iroquois. Dominion Energy Midstream and Dominion Energy Gas each account for their interest in Iroquois as an equity method investment. See Notes 9 and 15 for more information regarding Iroquois.

Acquisition of DECG

In January 2015, Dominion Energy completed the acquisition of 100% of the equity interests of DECG from SCANA for $497 million in cash, as adjusted for working capital. DECG owns and operates nearly 1,500 miles of FERC-regulated interstate natural gas pipeline in South Carolina and southeastern Georgia. This acquisition supports Dominion Energy's natural gas expansion into the southeastern U.S. The allocation of the purchase price resulted in $277 million of net property, plant and equipment, $250 million of goodwill, of which approximately $225 million is expected to be deductible for income tax purposes, and $38 million of regulatory liabilities. The goodwill reflects the value associated with enhancing Dominion Energy's regulated gas position, economic value attributable to future expansion projects as well as increased opportunities for synergies. The acquired assets of DECG are included in the Gas Infrastructure operating segment.

On March 24, 2015, DECG converted to a limited liability company under the laws of South Carolina and changed its name from Carolina Gas Transmission Corporation to DECG. On April 1, 2015, Dominion Energy contributed 100% of the issued and outstanding membership interests of DECG to Dominion Energy Midstream in exchange for total consideration of $501 million, as adjusted for working capital. Total consideration to Dominion Energy consisted of the issuance of a two-year, $301 million senior unsecured promissory note payable by Dominion Energy Midstream at an annual interest rate of 0.6%, and 5,112,139 common units, valued at $200 million, representing limited partner interests in Dominion Energy Midstream. The number of units was based on the volume weighted average trading price of Dominion Energy Midstream's common units for the ten trading days prior to April 1, 2015, or $39.12 per unit. Since Dominion Energy consolidates Dominion Energy Midstream for financial reporting purposes, this transaction was

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eliminated upon consolidation and did not impact Dominion Energy's financial position or cash flows.

VIRGINIA POWER

Acquisition of Solar Projects

In December 2015, Virginia Power completed the acquisition of 100% of a solar development project in North Carolina from Morgans Corner for $47 million, all of which was allocated to property, plant and equipment. The project was placed into service in December 2015 with a total cost of $49 million, including the initial acquisition cost. The project generates 20 MW. The output generated by the project is used to meet a ten-year non-jurisdictional supply agreement with the U.S. Navy, which has the unilateral option to extend for an additional ten years. In October 2015, the North Carolina Commission granted the transfer of the existing CPCN from Morgans Corner to Virginia Power. The acquired asset is included in the Power Generation operating segment.

DOMINION ENERGY AND DOMINION ENERGY GAS

Blue Racer

See Note 9 for a discussion of transactions related to Blue Racer.

NOTE 4. OPERATING REVENUE

The Companies' operating revenue consists of the following:

Year Ended December 31, (millions)	2017	2016	2015
Dominion Energy			
Electric sales:			
Regulated	**$ 7,383**	$ 7,348	$ 7,482
Nonregulated	**1,429**	1,519	1,488
Gas sales:			
Regulated	**1,067**	500	218
Nonregulated	**457**	354	471
Gas transportation and storage	**1,786**	1,636	1,616
Other	**464**	380	408
Total operating revenue	**$12,586**	$11,737	$11,683
Virginia Power			
Regulated electric sales	**$ 7,383**	$ 7,348	$ 7,482
Other	**173**	240	140
Total operating revenue	**$ 7,556**	$ 7,588	$ 7,622
Dominion Energy Gas			
Gas sales:			
Regulated	**$ 87**	$ 119	$ 122
Nonregulated	**20**	13	10
Gas transportation and storage	**1,435**	1,307	1,366
NGL revenue	**91**	62	93
Other	**181**	137	125
Total operating revenue	**$ 1,814**	$ 1,638	$ 1,716

NOTE 5. INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. The Companies are routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

The 2017 Tax Reform Act includes a broad range of tax reform provisions affecting the Companies as discussed in Note 2. The 2017 Tax Reform Act reduces the corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. At the date of enactment, deferred tax assets and liabilities were remeasured based upon the new 21% enacted tax rate expected to apply when temporary differences are realized or settled. The specific provisions related to regulated public utilities in the 2017 Tax Reform Act generally allows for the continued deductibility of interest expense, changes the tax depreciation of certain property acquired after September 27, 2017, and continues certain rate normalization requirements for accelerated depreciation benefits.

In December 2015, U.S. federal legislation was enacted, providing an extension of the 50% bonus depreciation allowance for qualifying expenditures incurred in 2015, 2016 and 2017. In addition, the legislation extended the 30% investment tax credit for qualifying expenditures incurred through 2019 and provides a phase down of the credit to 26% in 2020, 22% in 2021 and 10% in 2022 and thereafter.

As indicated in Note 2, certain of the Companies' operations, including accounting for income taxes, is subject to regulatory accounting treatment. For regulated operations, many of the changes in deferred taxes represent amounts probable of collection from or refund to customers, and are recorded as either an increase to a regulatory asset or liability. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes may be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred taxes may be determined by state and federal regulators. See Note 13 for more information.

The Companies have completed or have made a reasonable estimate for the measurement and accounting of certain effects of the 2017 Tax Reform Act which have been reflected in the Consolidated Financial Statements. The changes in deferred taxes were recorded as either an increase to a regulatory liability or as an adjustment to the deferred tax provision.

The items reflected as provisional amounts are related to accelerated depreciation for tax purposes of certain property acquired and placed into service after September 27, 2017 and the impact of accelerated depreciation on state income taxes to the extent there is uncertainty on conformity to the new federal tax system.

The determination of the income tax effects of the items reflected as provisional amounts represents a reasonable estimate, but will require additional analysis of historical records and further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Department of Treasury regulations, which will require more time, information and resources than currently available to the Companies.

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Continuing Operations

Details of income tax expense for continuing operations including noncontrolling interests were as follows:

	Dominion Energy			Virginia Power			Dominion Energy Gas		
Year Ended December 31,	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015
(millions)									
Current:									
Federal	**$ (1)**	$ (155)	$ (24)	**$432**	$168	$316	**$ 16**	$ (27)	$ 90
State	**(26)**	85	75	**73**	90	92	**8**	4	30
Total current expense (benefit)	**(27)**	(70)	51	**505**	258	408	**24**	(23)	120
Deferred:									
Federal									
2017 Tax Reform Act impact	**(851)**	—	—	**(93)**	—	—	**(197)**	—	—
Taxes before operating loss carryforwards and investment tax credits	**739**	1,050	384	**319**	435	154	**199**	239	156
Tax utilization expense (benefit) of operating loss carryforwards	**174**	(161)	539	**4**	(2)	96	**5**	(2)	6
Investment tax credits	**(200)**	(248)	(134)	**(23)**	(25)	(11)	**—**	—	—
State	**132**	50	66	**59**	27	13	**20**	1	1
Total deferred expense (benefit)	**(6)**	691	855	**266**	435	252	**27**	238	163
Investment tax credit-gross deferral	**5**	35	—	**5**	35	—	**—**	—	—
Investment tax credit-amortization	**(2)**	(1)	(1)	**(2)**	(1)	(1)	**—**	—	—
Total income tax expense (benefit)	**$ (30)**	$ 655	$ 905	**$774**	$727	$659	**$ 51**	$215	$283

The accounting for the reduction in the corporate income tax rate decreased deferred income tax expense by $851 million at Dominion Energy, $93 million at Virginia Power, and $197 million for Dominion Energy Gas for the year ending December 31, 2017. The decrease in deferred income taxes at Dominion Energy primarily relates to the remeasurement of deferred taxes on merchant operations and includes the effects at Virginia Power and Dominion Energy Gas. Virginia Power and Dominion Energy Gas have certain regulatory assets and liabilities that have not yet been charged or returned to customers through rates, or on which they do not earn a return, including unrecognized pension and other postretirement benefits. The remeasurement of the deferred taxes on these regulatory balances was charged to continuing operations in 2017. For ratemaking purposes, Dominion Energy Gas' subsidiary DETI follows the cash method on pension contributions. Deferred taxes recorded on pension balances as required by GAAP are not included as a component of rates and therefore the remeasurement of these deferred taxes were charged to continuing operations in 2017.

In 2016, Dominion Energy realized a taxable gain resulting from the contribution of Dominion Energy Questar Pipeline to Dominion Energy Midstream. The contribution and related transactions resulted in increases in the tax basis of Dominion Energy Questar Pipeline's assets and the number of Dominion Energy Midstream's common and convertible preferred units held by noncontrolling interests. The direct tax effects of the transactions included a provision for current income taxes ($212 million) and an offsetting benefit for deferred income taxes ($96 million) and were charged to common shareholders' equity. The federal tax liability was reduced by $129 million of tax credits generated in 2016 that otherwise would have resulted in additional credit carryforwards and a $17 million benefit provided by the domestic production activities deduction. These benefits, as indirect effects of the contribution transaction, were reflected in Dominion Energy's 2016 current federal income tax expense.

In 2015, Dominion Energy's current federal income tax benefit includes the recognition of a $20 million benefit related to a carryback to be filed for nuclear decommissioning expenditures included in its 2014 net operating loss.

For continuing operations including noncontrolling interests, the statutory U.S. federal income tax rate reconciles to the Companies' effective income tax rate as follows:

	Dominion Energy			Virginia Power			Dominion Energy Gas		
Year Ended December 31,	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015
U.S. statutory rate	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:									
State taxes, net of federal benefit	**2.0**	2.4	3.7	**3.7**	3.8	3.9	**2.4**	0.5	2.7
Investment tax credits	**(6.3)**	(11.7)	(4.7)	**(0.8)**	—	(0.6)	**—**	—	—
Production tax credits	**(0.7)**	(0.8)	(0.8)	**(0.4)**	(0.5)	(0.6)	**—**	—	—
Valuation allowances	**0.2**	1.2	(0.3)	**—**	0.1	—	**0.3**	—	—
Federal legislative change	**(27.5)**	—	—	**(4.0)**	—	—	**(29.5)**	—	—
State legislative change	**—**	(0.6)	(0.1)	**—**	—	—	**—**	—	—
AFUDC—equity	**(1.4)**	(0.6)	(0.3)	**(0.6)**	(0.6)	(0.6)	**(0.9)**	(0.2)	0.2
Employee stock ownership plan deduction	**(0.6)**	(0.6)	(0.6)	**—**	—	—	**—**	—	—
Other, net	**(1.7)**	(1.4)	0.1	**0.6**	(0.4)	0.6	**0.4**	0.1	0.3
Effective tax rate	**(1.0)%**	22.9%	32.0%	**33.5%**	37.4%	37.7%	**7.7%**	35.4%	38.2%

In 2017, the Companies' effective tax rates reflect the net benefit of remeasurement of deferred taxes resulting from the lower corporate income tax rate promulgated by the 2017 Tax Reform Act, and the completion of audits by state tax authorities that resulted in the recog-

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nition of previously unrecognized tax benefits. At December 31, 2016, Virginia Power's unrecognized tax benefits included state refund claims for open tax years through 2011. Management believed settlement of the claims, including interest thereon, within the next twelve months was remote. In June 2017, Virginia Power received and accepted a cash offer to settle the refund claims. As a result of the settlement, Virginia Power decreased its unrecognized tax benefits by $8 million, and recognized a $2 million tax benefit, which impacted its effective tax rate. Also in connection with this settlement, Virginia Power realized interest income of $11 million, which is reflected in other income in the Consolidated Statements of Income.

In 2016, Dominion Energy's effective tax rate reflects a valuation allowance on a state credit not expected to be utilized by a Dominion Energy subsidiary which files a separate state return.

The Companies' deferred income taxes consist of the following:

	Dominion Energy		Virginia Power		Dominion Energy Gas	
At December 31,	**2017**	2016	**2017**	2016	**2017**	2016
(millions)						
Deferred income taxes:						
Total deferred income tax assets	**$ 2,686**	$ 1,827	**$ 923**	$ 268	**$ 320**	$ 126
Total deferred income tax liabilities	**7,158**	10,381	**3,600**	5,323	**1,774**	2,564
Total net deferred income tax liabilities	**$ 4,472**	$ 8,554	**$2,677**	$5,055	**$1,454**	$ 2,438
Total deferred income taxes:						
Plant and equipment, primarily depreciation method and basis differences	**$ 5,056**	$ 7,782	**$2,969**	$4,604	**$1,132**	$ 1,726
Excess deferred income taxes	**(1,050)**	—	**(687)**	—	**(244)**	—
Nuclear decommissioning	**829**	1,240	**260**	406	**—**	—
Deferred state income taxes	**834**	747	**378**	321	**227**	204
Federal benefit of deferred state income taxes	**(175)**	(261)	**(79)**	(112)	**(48)**	(71)
Deferred fuel, purchased energy and gas costs	**1**	(25)	**(3)**	(29)	**2**	4
Pension benefits	**141**	155	**(104)**	(138)	**419**	646
Other postretirement benefits	**(51)**	(68)	**44**	49	**(2)**	(6)
Loss and credit carryforwards	**(1,536)**	(1,547)	**(111)**	(88)	**(4)**	(5)
Valuation allowances	**146**	135	**5**	3	**3**	—
Partnership basis differences	**473**	688	**—**	—	**26**	43
Other	**(196)**	(292)	**5**	39	**(57)**	(103)
Total net deferred income tax liabilities	**$ 4,472**	$ 8,554	**$2,677**	$5,055	**$1,454**	$ 2,438
Deferred Investment Tax Credits – Regulated Operations	**51**	48	**51**	48	**—**	—
Total Deferred Taxes and Deferred Investment Tax Credits	**$ 4,523**	$ 8,602	**$2,728**	$5,103	**$1,454**	$ 2,438

The most significant impact reflected for the 2017 Tax Reform Act is the adjustment of the net accumulated deferred income tax liability for the reduction in the corporate income tax rate to 21%. In addition to amounts recognized in deferred income tax expense, the impacts of the 2017 Tax Reform Act decreased the accumulated deferred income tax liability by $3.1 billion at Dominion Energy, $1.9 billion at Virginia Power and $0.8 billion at Dominion Energy Gas at December 31, 2017. At Dominion Energy, the December 31, 2017 balance sheet reflects the impact of the 2017 Tax Reform Act on our regulatory liabilities which increased our regulatory liabilities by $4.2 billion, and created a corresponding deferred tax asset of $1.1 billion. At Virginia Power, our regulatory liabilities increased $2.6 billion, and created a deferred tax asset of $0.7 billion. At Dominion Energy Gas, our regulatory liabilities increased $1.0 billion, and created a deferred tax asset of $0.2 billion. These adjustments had no impact on 2017 cash flows.

At December 31, 2017, Dominion Energy had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$ 560**	**$ 118**	**$ —**	**2034**
Federal investment credits	**—**	**938**	**—**	**2033-2037**
Federal production credits	**—**	**129**	**—**	**2031-2037**
Other federal credits	**—**	**58**	**—**	**2031-2037**
State losses	**1,366**	**103**	**(63)**	**2018-2037**
State minimum tax credits	**—**	**90**	**—**	**No expiration**
State investment and other credits	**—**	**100**	**(83)**	**2018-2027**
Total	**$1,926**	**$1,536**	**$(146)**	

At December 31, 2017, Virginia Power had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$ 1**	**$ —**	**$—**	**2034**
Federal investment credits	**—**	**51**	**—**	**2034-2037**
Federal production and other credits	**—**	**51**	**—**	**2031-2037**
State investment credits	**—**	**9**	**(5)**	**2024**
Total	**$ 1**	**$111**	**$(5)**	

At December 31, 2017, Dominion Energy Gas had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Other federal credits	**$ —**	**$1**	**$ —**	**2032-2036**
State losses	**33**	**3**	**(3)**	**2036-2037**
Total	**$33**	**$4**	**$ (3)**	

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A reconciliation of changes in the Companies' unrecognized tax benefits follows:

	Dominion Energy			Virginia Power			Dominion Energy Gas		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
(millions)									
Balance at January 1	**$ 64**	$103	$145	**$13**	$12	$ 36	**$ 7**	$ 29	$29
Increases-prior period positions	**1**	9	2	**—**	4	—	**—**	1	—
Decreases-prior period positions	**(9)**	(44)	(40)	**(1)**	(3)	(25)	**—**	(19)	—
Increases-current period positions	**5**	6	8	**—**	—	1	**—**	—	—
Settlements with tax authorities	**(23)**	(8)	(5)	**(8)**	—	—	**(7)**	(4)	—
Expiration of statutes of limitations	**—**	(2)	(7)	**—**	—	—	**—**	—	—
Balance at December 31	**$ 38**	$ 64	$103	**$ 4**	$13	$ 12	**$—**	$ 7	$29

Certain unrecognized tax benefits, or portions thereof, if recognized, would affect the effective tax rate. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations. For Dominion Energy and its subsidiaries, these unrecognized tax benefits were $31 million, $45 million and $69 million at December 31, 2017, 2016 and 2015, respectively. For Dominion Energy, the change in these unrecognized tax benefits decreased income tax expense by $9 million, $18 million and $6 million in 2017, 2016 and 2015, respectively. For Virginia Power, these unrecognized tax benefits were $3 million, $9 million, and $8 million at December 31, 2017, 2016 and 2015, respectively. For Virginia Power, the change in these unrecognized tax benefits decreased income tax expense by $6 million in 2017 and increased income tax expense by $1 million and less than $1 million in 2016 and 2015, respectively. For Dominion Energy Gas, these unrecognized tax benefits were less than $1 million, $5 million and $19 million at December 31, 2017, 2016 and 2015, respectively. For Dominion Energy Gas, the change in these unrecognized tax benefits decreased income tax expense by $5 million, $11 million and less than $1 million in 2017, 2016 and 2015, respectively.

Dominion Energy participates in the IRS Compliance Assurance Process which provides the opportunity to resolve complex tax matters with the IRS before filing its federal income tax returns, thus achieving certainty for such tax return filing positions agreed to by the IRS. In 2016 and 2017, the Companies submitted research credit claims for tax years 2012-2016. These claims are currently under IRS examination. With the exception of these research credit claims, the IRS has completed its audit of tax years through 2015. The statute of limitations has not yet expired for tax years after 2012. Although Dominion Energy has not received a final letter indicating no changes to its taxable income for tax year 2016, no material adjustments are expected. The IRS examination of tax year 2017 is ongoing.

It is reasonably possible that settlement negotiations and expiration of statutes of limitations could result in a decrease in unrecognized tax benefits in 2018 by up to $13 million for Dominion Energy, $2 million for Virginia Power and less than $1 million for Dominion Energy Gas. If such changes were to occur, other than revisions of the accrual for interest on tax underpayments and overpayments, earnings could increase by up to $12 million for Dominion Energy, $2 million for Virginia Power and less than $1 million for Dominion Energy Gas.

Otherwise, with regard to 2017 and prior years, Dominion Energy, Virginia Power and Dominion Energy Gas cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2018.

For each of the major states in which Dominion Energy operates, the earliest tax year remaining open for examination is as follows:

State	Earliest Open Tax Year
Pennsylvania(1)	**2012**
Connecticut	**2014**
Virginia(2)	**2014**
West Virginia(1)	**2014**
New York(1)	**2011**
Utah	**2014**

(1) Considered a major state for Dominion Energy Gas' operations.
(2) Considered a major state for Virginia Power's operations.

The Companies are also obligated to report adjustments resulting from IRS settlements to state tax authorities. In addition, if Dominion Energy utilizes operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

NOTE 6. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, the use of a mid-market pricing convention (the mid-point between bid and ask prices) is permitted. Fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of the Companies' own nonperformance risk on their liabilities. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). Dominion Energy applies fair value measurements to certain assets and liabilities including commodity, interest rate, and foreign currency derivative instruments, and other investments including those held in nuclear decommissioning, Dominion Energy's rabbi, and pension and other postretirement benefit plan trusts, in accordance with the requirements discussed above. Virginia Power applies fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments and other investments including those held in the nuclear decommissioning trust, in accordance with the requirements discussed above. Dominion Energy Gas applies fair value measurements to certain assets and liabilities including commodity, interest rate, and foreign currency derivative instruments and other investments including those held in pension and other postretirement benefit plan trusts, in accordance with the requirements described above. The Companies apply credit adjustments to their derivative fair values in accordance with the requirements described above.

Inputs and Assumptions

The Companies maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, price information is sought from external sources, including broker quotes and industry publications. When evaluating pricing information provided by brokers and other pricing services, the Companies consider whether the broker is willing and able to trade at the quoted price, if the broker quotes are based on an active market or an inactive market and the extent to which brokers are utilizing a particular model if pricing is not readily available. If pricing information from external sources is not available, or if the Companies believe that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases the Companies must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis, that reflect their market assumptions.

The Companies' commodity derivative valuations are prepared by Dominion Energy's ERM department. The ERM department creates daily mark-to-market valuations for the Companies' derivative transactions using computer-based statistical models. The inputs that go into the market valuations are transactional information stored in the systems of record and market pricing information that resides in data warehouse databases. The majority of forward prices are automatically uploaded into the data warehouse databases from various third-party sources. Inputs obtained from third-party sources are evaluated for reliability considering the reputation, independence, market presence, and methodology used by the third-party. If forward prices are not available from third-party sources, then the ERM department models the forward prices based on other available market data. A team consisting of risk management and risk quantitative analysts meets each business day to assess the validity of market prices and mark-to-market valuations. During this meeting, the changes in mark-to-market valuations from period to period are examined and qualified against historical expectations. If any discrepancies are identified during this process, the mark-to-market valuations or the market pricing information is evaluated further and adjusted, if necessary.

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, Dominion Energy and Virginia Power generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. Dominion Energy and Virginia Power use other option models under special circumstances, including a Spread Approximation Model when contracts include different commodities or commodity locations and a Swing Option Model when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, the Companies may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract's estimated fair value.

The inputs and assumptions used in measuring fair value include the following:

For commodity derivative contracts:

- Forward commodity prices
- Transaction prices
- Price volatility
- Price correlation
- Volumes
- Commodity location
- Interest rates
- Credit quality of counterparties and the Companies
- Credit enhancements
- Time value

For interest rate derivative contracts:

- Interest rate curves
- Credit quality of counterparties and the Companies
- Notional value
- Credit enhancements
- Time value

For foreign currency derivative contracts:

- Foreign currency forward exchange rates
- Interest rates
- Credit quality of counterparties and the Companies
- Notional value
- Credit enhancements
- Time value

For investments:

- Quoted securities prices and indices
- Securities trading information including volume and restrictions
- Maturity
- Interest rates
- Credit quality

The Companies regularly evaluate and validate the inputs used to estimate fair value by a number of methods, including review and verification of models, as well as various market price verification procedures such as the use of pricing services and multiple broker quotes to support the market price of the various commodities and investments in which the Companies transact.

Levels

The Companies also utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1—Quoted prices (unadjusted) in active markets for identical assets and liabilities that they have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as certain exchange-traded derivatives, and exchange-listed equities, U.S. and international equity securities, mutual funds and certain Treasury securities held in nuclear decommissioning

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trust funds for Dominion Energy and Virginia Power, benefit plan trust funds for Dominion Energy and Dominion Energy Gas, and rabbi trust funds for Dominion Energy.

- Level 2—Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include commodity forwards and swaps, interest rate swaps, foreign currency swaps and cash and cash equivalents, corporate debt instruments, government securities and other fixed income investments held in nuclear decommissioning trust funds for Dominion Energy and Virginia Power, benefit plan trust funds for Dominion Energy and Dominion Energy Gas and rabbi trust funds for Dominion Energy.
- Level 3—Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 for the Companies consist of long-dated commodity derivatives, FTRs, certain natural gas and power options and other modeled commodity derivatives.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, the lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. Alternative investments, consisting of investments in partnerships, joint ventures and other alternative investments held in nuclear decommissioning and benefit plan trust funds, are generally valued using NAV based on the proportionate share of the fair value as determined by reference to the most recent audited fair value financial statements or fair value statements provided by the investment manager adjusted for any significant events occurring between the investment manager's and the Companies' measurement date. Alternative investments recorded at NAV are not classified in the fair value hierarchy.

For derivative contracts, the Companies recognize transfers among Level 1, Level 2 and Level 3 based on fair values as of the first day of the month in which the transfer occurs. Transfers out of Level 3 represent assets and liabilities that were previously classified as Level 3 for which the inputs became observable for classification in either Level 1 or Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Companies' over-the-counter derivative contracts is subject to change.

Level 3 Valuations

Fair value measurements are categorized as Level 3 when price or other inputs that are considered to be unobservable are significant to their valuations. Long-dated commodity derivatives are generally based on unobservable inputs due to the length of time to settlement and the absence of market activity and are therefore categorized as Level 3. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from ISO auctions, which are generally not considered to be liquid markets. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

The Companies enter into certain physical and financial forwards, futures, options and swaps, which are considered Level 3 as they have one or more inputs that are not observable and are significant to the valuation. The discounted cash flow method is used to value Level 3 physical and financial forwards and futures contracts. An option model is used to value Level 3 physical and financial options. The discounted cash flow model for forwards and futures calculates mark-to-market valuations based on forward market prices, original transaction prices, volumes, risk-free rate of return, and credit spreads. The option model calculates mark-to-market valuations using variations of the Black-Scholes option model. The inputs into the models are the forward market prices, implied price volatilities, risk-free rate of return, the option expiration dates, the option strike prices, the original sales prices, and volumes. For Level 3 fair value measurements, certain forward market prices and implied price volatilities are considered unobservable. The unobservable inputs are developed and substantiated using historical information, available market data, third-party data, and statistical analysis. Periodically, inputs to valuation models are reviewed and revised as needed, based on historical information, updated market data, market liquidity and relationships, and changes in third-party pricing sources.

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The following table presents Dominion Energy's quantitative information about Level 3 fair value measurements at December 31, 2017. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets					
Physical and financial forwards and futures:					
Natural gas(2)	**$ 84**	Discounted cash flow	Market price (per Dth)(4)	(2) - 14	—
FTRs	**29**	Discounted cash flow	Market price (per MWh)(4)	(1) - 7	2
Physical options:					
Natural gas	**1**	Option model	Market price (per Dth)(4)	2 - 7	3
			Price volatility (5)	26% - 54%	33%
Electricity	**43**	Option model	Market price (per MWh)(4)	22 - 74	37
			Price volatility (5)	13% - 63%	33%
Total assets	**$157**				
Liabilities					
Financial forwards:					
Liquids(3)	**$ 2**	Discounted cash flow	Market price (per Gal)(4)	0 - 2	1
FTRs	**$ 5**	Discounted cash flow	Market price (per MWh)(4)	(4) - 6	—
Total liabilities	**$ 7**				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Includes NGLs and oil.
(4) Represents market prices beyond defined terms for Levels 1 and 2.
(5) Represents volatilities unrepresented in published markets.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)
Price volatility	Buy	Increase (decrease)	Gain (loss)
Price volatility	Sell	Increase (decrease)	Loss (gain)

Nonrecurring Fair Value Measurements

DOMINION ENERGY

See Note 9 for information regarding an impairment charge recognized associated with Dominion Energy's equity method investment in Fowler Ridge.

ATLANTIC COAST PIPELINE GUARANTEE AGREEMENT

In October 2017, Dominion Energy entered into a guarantee agreement in connection with Atlantic Coast Pipeline's obligation under a $3.4 billion revolving credit facility. See Note 22 for more information about the guarantee agreement associated with Atlantic Coast Pipeline's revolving credit facility. Dominion Energy recorded a liability of $30 million, the fair value of the guarantee at inception, associated with the guarantee agreement. The fair value was estimated using a discounted cash flow method and is considered a Level 3 fair value measurement due to the use of a significant unobservable input related to the interest rate differential between the interest rate charged on the guaranteed revolving credit facility and the estimated interest rate that would have been charged had the loan not been guaranteed.

Recurring Fair Value Measurements

Fair value measurements are separately disclosed by level within the fair value hierarchy with a separate reconciliation of fair value measurements categorized as Level 3. Fair value disclosures for assets held in Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans are presented in Note 21.

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DOMINION ENERGY

The following table presents Dominion Energy's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
December 31, 2017				
Assets				
Derivatives:				
Commodity	**$ —**	**$ 101**	**$157**	**$ 258**
Interest rate	**—**	**17**	**—**	**17**
Foreign currency	**—**	**32**	**—**	**32**
Investments(1):				
Equity securities:				
U.S.	**3,493**	**—**	**—**	**3,493**
Fixed income:				
Corporate debt instruments	**—**	**444**	**—**	**444**
Government securities	**307**	**794**	**—**	**1,101**
Cash equivalents and other	**34**	**—**	**—**	**34**
Total assets	**$3,834**	$1,388	$157	$5,379
Liabilities				
Derivatives:				
Commodity	**$ —**	**$ 190**	**$ 7**	**$ 197**
Interest rate	**—**	**85**	**—**	**85**
Foreign currency	**—**	**2**	**—**	**2**
Total liabilities	**$ —**	**$ 277**	**$ 7**	**$ 284**
December 31, 2016				
Assets				
Derivatives:				
Commodity	$ —	$ 115	$147	$ 262
Interest rate	—	17	—	17
Investments(1):				
Equity securities:				
U.S.	2,913	—	—	2,913
Fixed income:				
Corporate debt instruments	—	487	—	487
Government securities	424	614	—	1,038
Cash equivalents and other	5	—	—	5
Total assets	$3,342	$1,233	$147	$4,722
Liabilities				
Derivatives:				
Commodity	$ —	$ 88	$ 8	$ 96
Interest rate	—	53	—	53
Foreign currency	—	6	—	6
Total liabilities	$ —	$ 147	$ 8	$ 155

(1) Includes investments held in the nuclear decommissioning and rabbi trusts. Excludes $88 million and $89 million of assets at December 31, 2017 and 2016, respectively, measured at fair value using NAV (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

The following table presents the net change in Dominion Energy's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	2017	2016	2015
Balance at January 1,	**$139**	$ 95	$107
Total realized and unrealized gains (losses):			
Included in earnings	**(38)**	(35)	(5)
Included in other comprehensive loss	**(2)**	—	(9)
Included in regulatory assets/liabilities	**42**	(39)	(4)
Settlements	**6**	38	9
Purchases	**—**	87	—
Transfers out of Level 3	**3**	(7)	(3)
Balance at December 31,	**$150**	$139	$ 95
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	**$ 2**	$ (1)	$ 2

The following table presents Dominion Energy's gains and losses included in earnings in the Level 3 fair value category:

(millions)	Operating Revenue	Electric Fuel and Other Energy-Related Purchases	Purchased Gas	Total
Year Ended December 31, 2017				
Total gains (losses) included in earnings	**$ 3**	**$(42)**	**$ 1**	**$(38)**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	**2**	**—**	**—**	**2**
Year Ended December 31, 2016				
Total gains (losses) included in earnings	$—	$(35)	$—	$(35)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	—	(1)	—	(1)
Year Ended December 31, 2015				
Total gains (losses) included in earnings	$ 6	$(11)	$—	$ (5)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	1	1	—	2

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Combined Notes to Consolidated Financial Statements, Continued

VIRGINIA POWER

The following table presents Virginia Power's quantitative information about Level 3 fair value measurements at December 31, 2017. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets					
Physical and financial forwards and futures:					
Natural gas(2)	**$ 81**	Discounted cash flow	Market price (per Dth)(3)	(2)-7	(1)
FTRs	**27**	Discounted cash flow	Market price (per MWh)(3)	(1)-7	2
Physical options:					
Natural gas	**1**	Option model	Market price (per Dth)(3)	2-7	3
			Price volatility (4)	26%-54%	33%
Electricity	**43**	Option model	Market price (per MWh)(3)	22-74	37
			Price volatility (4)	13%-63%	33%
Total assets	**$152**				
Liabilities:					
Financial forwards:					
FTRs	**$ 5**	Discounted cash flow	Market price (per MWh)(3)	(4)-6	—
Total liabilities	**$ 5**				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Represents market prices beyond defined terms for Levels 1 and 2.
(4) Represents volatilities unrepresented in published markets.

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Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)
Price volatility	Buy	Increase (decrease)	Gain (loss)
Price volatility	Sell	Increase (decrease)	Loss (gain)

The following table presents Virginia Power's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

	Level 1	Level 2	Level 3	Total
(millions)				
December 31, 2017				
Assets				
Derivatives:				
Commodity	**$ —**	**$ 14**	**$152**	**$ 166**
Investments(1):				
Equity securities:				
U.S.	**1,566**	**—**	**—**	**1,566**
Fixed income:				
Corporate debt instruments	**—**	**224**	**—**	**224**
Government securities	**168**	**326**	**—**	**494**
Cash equivalents and other	**16**	**—**	**—**	**16**
Total assets	**$1,750**	**$564**	**$152**	**$2,466**
Liabilities				
Derivatives:				
Commodity	**$ —**	**$ 4**	**$ 5**	**$ 9**
Interest rate	**—**	**57**	**—**	**57**
Total liabilities	**$ —**	**$ 61**	**$ 5**	**$ 66**
December 31, 2016				
Assets				
Derivatives:				
Commodity	$ —	$ 43	$145	$ 188
Interest rate	—	6	—	6
Investments(1):				
Equity securities:				
U.S.	1,302	—	—	1,302
Fixed income:				
Corporate debt instruments	—	277	—	277
Government securities	136	291	—	427
Total assets	$1,438	$617	$145	$2,200
Liabilities				
Derivatives:				
Commodity	$ —	$ 8	$ 2	$ 10
Interest rate	—	21	—	21
Total liabilities	$ —	$ 29	$ 2	$ 31

(1) Includes investments held in the nuclear decommissioning trusts. Excludes $27 million and $26 million of assets at December 31, 2017 and 2016, respectively, measured at fair value using NAV (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

The following table presents the net change in Virginia Power's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

	2017	2016	2015
(millions)			
Balance at January 1,	**$143**	$ 93	$102
Total realized and unrealized gains (losses):			
Included in earnings	**(43)**	(35)	(13)
Included in regulatory assets/liabilities	**40**	(37)	(5)
Settlements	**7**	35	13
Purchases	**—**	87	—
Transfers out of Level 3	**—**	—	(4)
Balance at December 31,	**$147**	$143	$ 93

The gains and losses included in earnings in the Level 3 fair value category were classified in electric fuel and other energy-related purchases expense in Virginia Power's Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2017, 2016 and 2015.

DOMINION ENERGY GAS

The following table presents Dominion Energy Gas' quantitative information about Level 3 fair value measurements at December 31, 2017. The range and weighted average are presented in dollars for market price inputs.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Liabilities:					
Financial forwards:					
NGLs	**$2**	Discounted cash flow	Market price (per Dth)(2)	0 - 1	1
Total liabilities	**$2**				

(1) Averages weighted by volume.
(2) Represents market prices beyond defined terms for Levels 1 and 2.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

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The following table presents Dominion Energy Gas' assets and liabilities for commodity and foreign currency derivatives that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

	Level 1	Level 2	Level 3	Total
(millions)				
December 31, 2017				
Assets				
Foreign currency	**$ —**	**$32**	**$ —**	**$32**
Total assets	**$ —**	**$32**	**$ —**	**$32**
Liabilities				
Commodity	**$ —**	**$ 4**	**$ 2**	**$ 6**
Foreign currency	**—**	**2**	**—**	**2**
Total liabilities	**$ —**	**$ 6**	**$ 2**	**$ 8**
December 31, 2016				
Liabilities				
Commodity	$ —	$ 3	$ 2	$ 5
Foreign currency	—	6	—	6
Total liabilities	$ —	$ 9	$ 2	$11

The following table presents the net change in Dominion Energy Gas' derivative assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

	2017	2016	2015
(millions)			
Balance at January 1,	**$ (2)**	$ 6	$ 2
Total realized and unrealized gains (losses):			
Included in earnings	**—**	—	1
Included in other comprehensive loss	**(3)**	—	(5)
Settlements	**—**	—	(1)
Transfers out of Level 3	**3**	(8)	9
Balance at December 31,	**$ (2)**	$ (2)	$ 6

The gains and losses included in earnings in the Level 3 fair value category were classified in operating revenue in Dominion Energy Gas' Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2017, 2016 and 2015.

Fair Value of Financial Instruments

Substantially all of the Companies' financial instruments are recorded at fair value, with the exception of the instruments described below, which are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of cash and cash equivalents, restricted cash (which is recorded in other current assets), customer and other receivables, affiliated receivables, short-term debt, affiliated current borrowings, payables to affiliates and accounts payable are representative of fair value because of the short-term nature of these instruments. For the Companies' financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

December 31,	2017		2016	
	Carrying Amount	**Estimated Fair Value(1)**	Carrying Amount	Estimated Fair Value(1)
(millions)				
Dominion Energy				
Long-term debt, including securities due within one year(2)	**$28,666**	**$31,233**	$26,587	$28,273
Junior subordinated notes(3)	**3,981**	**4,102**	2,980	2,893
Remarketable subordinated notes(3)	**1,379**	**1,446**	2,373	2,418
Virginia Power				
Long-term debt, including securities due within one year(3)	**$11,346**	**$12,842**	$10,530	$11,584
Dominion Energy Gas				
Long-term debt, including securities due within one year(4)	**$ 3,570**	**$ 3,719**	$ 3,528	$ 3,603

(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. All fair value measurements are classified as Level 2. The carrying amount of debt issues with short-term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.

(2) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium, and foreign currency remeasurement adjustments. At December 31, 2017, and 2016, includes the valuation of certain fair value hedges associated with Dominion Energy's fixed rate debt of $(22) million and $(1) million, respectively.

(3) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium.

(4) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium, and foreign currency remeasurement adjustments.

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NOTE 7. DERIVATIVES AND HEDGE ACCOUNTING ACTIVITIES

The Companies are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products they market and purchase, as well as interest rate and foreign currency exchange rate risks of their business operations. The Companies use derivative instruments to manage exposure to these risks, and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes. As discussed in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivatives are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives.

Derivative assets and liabilities are presented gross on the Companies' Consolidated Balance Sheets. Dominion Energy's derivative contracts include both over-the-counter transactions and those that are executed on an exchange or other trading platform (exchange contracts) and centrally cleared. Virginia Power's and Dominion Energy Gas' derivative contracts include over-the-counter transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Exchange contracts utilize a financial intermediary, exchange, or clearinghouse to enter, execute, or clear the transactions. Certain over-the-counter and exchange contracts contain contractual rights of setoff through master netting arrangements, derivative clearing agreements, and contract default provisions. In addition, the contracts are subject to conditional rights of setoff through counterparty nonperformance, insolvency, or other conditions.

In general, most over-the-counter transactions and all exchange contracts are subject to collateral requirements. Types of collateral for over-the-counter and exchange contracts include cash, letters of credit, and, in some cases, other forms of security, none of which are subject to restrictions. Cash collateral is used in the table below to offset derivative assets and liabilities. Certain accounts receivable and accounts payable recognized on the Companies' Consolidated Balance Sheets, as well as letters of credit and other forms of security, all of which are not included in the tables below, are subject to offset under master netting or similar arrangements and would reduce the net exposure. See Note 23 for further information regarding credit-related contingent features for the Companies derivative instruments.

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Combined Notes to Consolidated Financial Statements, Continued

DOMINION ENERGY

Balance Sheet Presentation

The tables below present Dominion Energy's derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2017			December 31, 2016		
(millions)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$174	$—	$174	$211	$—	$211
Exchange	80	—	80	44	—	44
Interest rate contracts:						
Over-the-counter	17	—	17	17	—	17
Foreign currency contracts:						
Over-the-counter	32	—	32	—	—	—
Total derivatives, subject to a master netting or similar arrangement	303	—	303	272	—	272
Total derivatives, not subject to a master netting or similar arrangement	4	—	4	7	—	7
Total	$307	$—	$307	$279	$—	$279

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Commodity contracts:								
Over-the-counter	$174	$ 9	$—	$165	$211	$14	$—	$197
Exchange	80	80	—	—	44	44	—	—
Interest rate contracts:								
Over-the-counter	17	8	—	9	17	9	—	8
Foreign currency contracts:								
Over-the-counter	32	2	—	30	—	—	—	—
Total	$303	$99	$—	$204	$272	$67	$—	$205

	December 31, 2017			December 31, 2016		
(millions)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$ 76	$—	$ 76	$ 23	$—	$ 23
Exchange	120	—	120	71	—	71
Interest rate contracts:						
Over-the-counter	85	—	85	53	—	53
Foreign currency contracts:						
Over-the-counter	2	—	2	6	—	6
Total derivatives, subject to a master netting or similar arrangement	283	—	283	153	—	153
Total derivatives, not subject to a master netting or similar arrangement	1	—	1	2	—	2
Total	$284	$—	$284	$155	$—	$155

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	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Commodity contracts:								
Over-the-counter	$ 76	$ 9	$ 6	$ 61	$ 23	$14	$—	$ 9
Exchange	120	80	40	—	71	44	27	—
Interest rate contracts:								
Over-the-counter	85	8	—	77	53	9	—	44
Foreign currency contracts:								
Over-the-counter	2	2	—	—	6	—	—	6
Total	$283	$99	$46	$138	$153	$67	$27	$59

Volumes

The following table presents the volume of Dominion Energy's derivative activity as of December 31, 2017. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	77	19
Basis	163	600
Electricity (MWh):		
Fixed price	10,552,363	364,990
FTRs	46,494,865	—
Liquids (Gal)(2)	44,153,704	10,087,200
Interest rate(3)	$1,950,000,000	$4,192,517,177
Foreign currency(3)(4)	$ —	$ 280,000,000

(1) Includes options.
(2) Includes NGLs and oil.
(3) Maturity is determined based on final settlement period.
(4) Euro equivalent volumes are € 250,000,000.

Ineffectiveness and AOCI

For the years ended December 31, 2017, 2016 and 2015, gains or losses on hedging instruments determined to be ineffective and amounts excluded from the assessment of effectiveness were not material. Amounts excluded from the assessment of effectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion Energy's Consolidated Balance Sheet at December 31, 2017:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Commodities:			
Gas	$ (2)	$ (3)	34 months
Electricity	(55)	(55)	12 months
Other	(4)	(4)	15 months
Interest rate	(246)	(10)	384 months
Foreign currency	5	(1)	102 months
Total	$(302)	$(73)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign currency exchange rates.

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Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion Energy's derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value – Derivatives under Hedge Accounting	Fair Value – Derivatives not under Hedge Accounting	Total Fair Value
At December 31, 2017			
ASSETS			
Current Assets			
Commodity	**$ 5**	**$158**	**$163**
Interest rate	**6**	**—**	**6**
Total current derivative assets(1)	**11**	**158**	**169**
Noncurrent Assets			
Commodity	**—**	**95**	**95**
Interest rate	**11**	**—**	**11**
Foreign currency	**32**	**—**	**32**
Total noncurrent derivative assets(2)	**43**	**95**	**138**
Total derivative assets	**$ 54**	**$253**	**$307**
LIABILITIES			
Current Liabilities			
Commodity	**$103**	**$ 92**	**$195**
Interest rate	**53**	**—**	**53**
Foreign currency	**2**	**—**	**2**
Total current derivative liabilities(3)	**158**	**92**	**250**
Noncurrent Liabilities			
Commodity	**1**	**1**	**2**
Interest rate	**32**	**—**	**32**
Total noncurrent derivative liabilities(4)	**33**	**1**	**34**
Total derivative liabilities	**$191**	**$ 93**	**$284**
At December 31, 2016			
ASSETS			
Current Assets			
Commodity	$ 29	$101	$130
Interest rate	10	—	10
Total current derivative assets(1)	39	101	140
Noncurrent Assets			
Commodity	—	132	132
Interest rate	7	—	7
Total noncurrent derivative assets(2)	7	132	139
Total derivative assets	$ 46	$233	$279
LIABILITIES			
Current Liabilities			
Commodity	$ 51	$ 41	$ 92
Interest rate	33	—	33
Foreign currency	3	—	3
Total current derivative liabilities(3)	87	41	128
Noncurrent Liabilities			
Commodity	1	3	4
Interest rate	20	—	20
Foreign currency	3	—	3
Total noncurrent derivative liabilities(4)	24	3	27
Total derivative liabilities	$111	$ 44	$155

(1) Current derivative assets are presented in other current assets in Dominion Energy's Consolidated Balance Sheets.
(2) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion Energy's Consolidated Balance Sheets.
(3) Current derivative liabilities are presented in other current liabilities in Dominion Energy's Consolidated Balance Sheets.
(4) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion Energy's Consolidated Balance Sheets.

The following table presents the gains and losses on Dominion Energy's derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships (millions)	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified From AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)
Year Ended December 31, 2017			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue		**$ 81**	
Purchased gas		**(2)**	
Total commodity	**$ 1**	**$ 79**	**$ —**
Interest rate(3)	**(8)**	**(52)**	**(58)**
Foreign currency(4)	**18**	**20**	**—**
Total	**$ 11**	**$ 47**	**$(58)**
Year Ended December 31, 2016			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue		$330	
Purchased gas		(13)	
Electric fuel and other energy-related purchases		(10)	
Total commodity	$164	$307	$ —
Interest rate(3)	(66)	(31)	(26)
Foreign currency(4)	(6)	(17)	—
Total	$ 92	$259	$(26)
Year Ended December 31, 2015			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue		$203	
Purchased gas		(15)	
Electric fuel and other energy-related purchases		(1)	
Total commodity	$230	$187	$ 4
Interest rate(3)	(46)	(11)	(13)
Total	$184	$176	$ (9)

(1) Amounts deferred into AOCI have no associated effect in Dominion Energy's Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion Energy's Consolidated Statements of Income.
(3) Amounts recorded in Dominion Energy's Consolidated Statements of Income are classified in interest and related charges.
(4) Amounts recorded in Dominion Energy's Consolidated Statements of Income are classified in other income.

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Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives(1)		
Year Ended December 31,	**2017**	2016	2015
(millions)			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue	**$ 18**	$ 2	$ 24
Purchased gas	**(3)**	4	(14)
Electric fuel and other energy-related purchases	**(59)**	(70)	(14)
Other operations & maintenance	**(1)**	1	—
Interest rate(2)	**—**	—	(1)
Total	**$(45)**	$(63)	$ (5)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion Energy's Consolidated Statements of Income.
(2) Amounts recorded in Dominion Energy's Consolidated Statements of Income are classified in interest and related charges.

VIRGINIA POWER

Balance Sheet Presentation

The tables below present Virginia Power's derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2017			December 31, 2016		
	Gross Amounts of Recognized Assets	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts of Assets Presented in the Consolidated Balance Sheet**	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
(millions)						
Commodity contracts:						
Over-the-counter	**$155**	**$—**	**$155**	$147	$—	$147
Interest rate contracts:						
Over-the-counter	**—**	**—**	**—**	6	—	6
Total derivatives, subject to a master netting or similar arrangement	**155**	**—**	**155**	153	—	153
Total derivatives, not subject to a master netting or similar arrangement	**11**	**—**	**11**	41	—	41
Total	**$166**	**$—**	**$166**	$194	$—	$194

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Assets Presented in the Consolidated Balance Sheet	**Financial Instruments**	**Cash Collateral Received**	**Net Amounts**	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
(millions)								
Commodity contracts:								
Over-the-counter	**$155**	**$ 4**	**$—**	**$151**	$147	$ 2	$—	$145
Interest rate contracts:								
Over-the-counter	**—**	**—**	**—**	**—**	6	—	—	6
Total	**$155**	**$ 4**	**$—**	**$151**	$153	$ 2	$—	$151

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Combined Notes to Consolidated Financial Statements, Continued

(millions)	December 31, 2017 Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	December 31, 2016 Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$ 4	$—	$ 4	$ 2	$—	$ 2
Interest rate contracts:						
Over-the-counter	57	—	57	21	—	21
Total derivatives, subject to a master netting or similar arrangement	61	—	61	23	—	23
Total derivatives, not subject to a master netting or similar arrangement	5	—	5	8	—	8
Total	$66	$—	$66	$31	$—	$31

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Commodity contracts:								
Over-the-counter	$ 4	$ 4	$—	$—	$ 2	$ 2	$—	$—
Interest rate contracts:								
Over-the-counter	57	—	—	57	21	—	—	21
Total	$61	$ 4	$—	$57	$23	$ 2	$—	$21

Volumes

The following table presents the volume of Virginia Power's derivative activity at December 31, 2017. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	33	5
Basis	79	540
Electricity (MWh):		
Fixed price(1)	1,453,910	364,990
FTRs	42,582,981	—
Interest rate(2)	$1,150,000,000	$300,000,000

(1) Includes options.
(2) Maturity is determined based on final settlement period.

Ineffectiveness and AOCI

For the years ended December 31, 2017, 2016 and 2015, gains or losses on hedging instruments determined to be ineffective were not material.

The following table presents selected information related to losses on cash flow hedges included in AOCI in Virginia Power's Consolidated Balance Sheet at December 31, 2017:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$(12)	$(1)	384 months
Total	$(12)	$(1)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., interest payments) in earnings, thereby achieving the realization of interest rates contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in interest rates.

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Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Virginia Power's derivatives and where they are presented in its Consolidated Balance Sheets:

	Fair Value - Derivatives under Hedge Accounting	Fair Value - Derivatives not under Hedge Accounting	Total Fair Value
(millions)			
At December 31, 2017			
ASSETS			
Current Assets			
Commodity	**$—**	**$ 75**	**$ 75**
Total current derivative assets(1)	**—**	**75**	**75**
Noncurrent Assets			
Commodity	**—**	**91**	**91**
Total noncurrent derivative assets	**—**	**91**	**91**
Total derivative assets	**$—**	**$166**	**$166**
LIABILITIES			
Current Liabilities			
Commodity	**$—**	**$ 9**	**$ 9**
Interest rate	**44**	**—**	**44**
Total current derivative liabilities(2)	**44**	**9**	**53**
Noncurrent Liabilities			
Interest rate	**13**	**—**	**13**
Total noncurrent derivatives liabilities(3)	**13**	**—**	**13**
Total derivative liabilities	**$57**	**$ 9**	**$ 66**
At December 31, 2016			
ASSETS			
Current Assets			
Commodity	$—	$ 60	$ 60
Interest rate	6	—	6
Total current derivative assets(1)	6	60	66
Noncurrent Assets			
Commodity	—	128	128
Total noncurrent derivative assets	—	128	128
Total derivative assets	$6	$188	$194
LIABILITIES			
Current Liabilities			
Commodity	$—	$ 10	$ 10
Interest rate	8	—	8
Total current derivative liabilities(2)	8	10	18
Noncurrent Liabilities			
Interest rate	13	—	13
Total noncurrent derivative liabilities(3)	13	—	13
Total derivative liabilities	$21	$ 10	$ 31

(1) Current derivative assets are presented in other current assets in Virginia Power's Consolidated Balance Sheets.
(2) Current derivative liabilities are presented in other current liabilities in Virginia Power's Consolidated Balance Sheets.
(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Virginia Power's Consolidated Balance Sheets.

The following tables present the gains and losses on Virginia Power's derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified From AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)
(millions)			
Year Ended December 31, 2017			
Derivative type and location of gains (losses):			
Interest rate(3)	**$(8)**	**$(1)**	**$(58)**
Total	**$(8)**	**$(1)**	**$(58)**
Year Ended December 31, 2016			
Derivative type and location of gains (losses):			
Interest rate(3)	$(3)	$(1)	$(26)
Total	$(3)	$(1)	$(26)
Year Ended December 31, 2015			
Derivative type and location of gains (losses):			
Commodity:			
Electric fuel and other energy-related purchases		$(1)	
Total commodity	$—	$(1)	$ 4
Interest rate(3)	(3)	—	(13)
Total	$(3)	$(1)	$ (9)

(1) Amounts deferred into AOCI have no associated effect in Virginia Power's Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power's Consolidated Statements of Income.
(3) Amounts recorded in Virginia Power's Consolidated Statements of Income are classified in interest and related charges.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives(1)		
Year Ended December 31,	**2017**	2016	2015
(millions)			
Derivative type and location of gains (losses):			
Commodity(2)	**$(57)**	$(70)	$(13)
Total	**$(57)**	$(70)	$(13)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power's Consolidated Statements of Income.
(2) Amounts recorded in Virginia Power's Consolidated Statements of Income are classified in electric fuel and other energy-related purchases.

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Combined Notes to Consolidated Financial Statements, Continued

DOMINION ENERGY GAS

Balance Sheet Presentation

The tables below present Dominion Energy Gas' derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2017			December 31, 2016		
(millions)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Foreign currency contracts:						
Over-the-counter	$32	$—	$32	$—	$—	$—
Total derivatives, subject to a master netting or similar arrangement	$32	$—	$32	$—	$—	$—

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Foreign currency contracts:								
Over-the-counter	$32	$2	$—	$30	$—	$—	$—	$—
Total	$32	$2	$—	$30	$—	$—	$—	$—

	December 31, 2017			December 31, 2016		
(millions)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$6	$—	$6	$ 5	$—	$ 5
Foreign currency contracts:						
Over-the-counter	2	—	2	6	—	6
Total derivatives, subject to a master netting or similar arrangement	$8	$—	$8	$11	$—	$11

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Commodity contracts								
Over-the-counter	$6	$—	$—	$ 6	$ 5	$—	$—	$ 5
Foreign currency contracts:								
Over-the-counter	2	2	—	—	6	—	—	6
Total	$8	$ 2	$—	$ 6	$11	$—	$—	$11

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Volumes

The following table presents the volume of Dominion Energy Gas' derivative activity at December 31, 2017. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Basis	**1**	**—**
NGLs (Gal)	**40,961,704**	**8,491,200**
Foreign currency(1)	**$ —**	**$280,000,000**

(1) Maturity is determined based on final settlement period. Euro equivalent volumes are €250,000,000.

Ineffectiveness and AOCI

For the years ended December 31, 2017, 2016 and 2015, gains or losses on hedging instruments determined to be ineffective were not material.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion Energy Gas' Consolidated Balance Sheet at December 31, 2017:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Commodities:			
NGLs	**$ (4)**	**$(4)**	**15 months**
Interest rate	**(25)**	**(3)**	**324 months**
Foreign currency	**6**	**(1)**	**102 months**
Total	**$(23)**	**$(8)**	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates, and foreign currency exchange rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion Energy Gas' derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value-Derivatives Under Hedge Accounting	Fair Value-Derivatives Not Under Hedge Accounting	Total Fair Value
At December 31, 2017			
ASSETS			
Noncurrent Assets			
Foreign currency	**$32**	**$—**	**$32**
Total noncurrent derivative assets(1)	**32**	**—**	**32**
Total derivative assets	**$32**	**$—**	**$32**
LIABILITIES			
Current Liabilities			
Commodity	**$ 6**	**$—**	**$ 6**
Foreign currency	**2**	**—**	**2**
Total current derivative liabilities(2)	**8**	**—**	**8**
Total derivative liabilities	**$ 8**	**$—**	**$ 8**
At December 31, 2016			
LIABILITIES			
Current Liabilities			
Commodity	$ 4	$—	$ 4
Foreign currency	3	—	3
Total current derivative liabilities(2)	7	—	7
Noncurrent Liabilities			
Commodity	1	—	1
Foreign currency	3	—	3
Total noncurrent derivative liabilities(3)	4	—	4
Total derivative liabilities	$11	$—	$11

(1) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion Energy Gas' Consolidated Balance Sheets.
(2) Current derivative liabilities are presented in other current liabilities in Dominion Energy Gas' Consolidated Balance Sheets.
(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion Energy Gas' Consolidated Balance Sheets.

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The following tables present the gains and losses on Dominion Energy Gas' derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified From AOCI to Income
(millions)		
Year Ended December 31, 2017		
Derivative Type and Location of Gains (Losses):		
Commodity:		
Operating revenue		**$ (8)**
Total commodity	**$(10)**	**$ (8)**
Interest rate(2)	**—**	**(5)**
Foreign currency(3)	**18**	**20**
Total	**$ 8**	**$ 7**
Year Ended December 31, 2016		
Derivative Type and Location of Gains (Losses):		
Commodity:		
Operating revenue		$ 4
Total commodity	$(12)	$ 4
Interest rate(2)	(8)	(2)
Foreign currency(3)	(6)	(17)
Total	$(26)	$(15)
Year Ended December 31, 2015		
Derivative Type and Location of Gains (Losses):		
Commodity:		
Operating revenue		$ 6
Total commodity	$ 16	$ 6
Interest rate(2)	(6)	—
Total	$ 10	$ 6

(1) Amounts deferred into AOCI have no associated effect in Dominion Energy Gas' Consolidated Statements of Income.
(2) Amounts recorded in Dominion Energy Gas' Consolidated Statements of Income are classified in interest and related charges.
(3) Amounts recorded in Dominion Energy Gas' Consolidated Statements of Income are classified in other income.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives		
Year Ended December 31,	**2017**	2016	2015
(millions)			
Derivative type and location of gains (losses):			
Commodity			
Operating revenue	**$—**	$1	$6
Total	**$—**	$1	$6

NOTE 8. EARNINGS PER SHARE

The following table presents the calculation of Dominion Energy's basic and diluted EPS:

	2017	2016	2015
(millions, except EPS)			
Net income attributable to Dominion Energy	**$2,999**	$2,123	$1,899
Average shares of common stock outstanding – Basic	**636.0**	616.4	592.4
Net effect of dilutive securities(1)	**—**	0.7	1.3
Average shares of common stock outstanding – Diluted	**636.0**	617.1	593.7
Earnings Per Common Share – Basic	**$ 4.72**	$ 3.44	$ 3.21
Earnings Per Common Share – Diluted	**$ 4.72**	$ 3.44	$ 3.20

(1) Dilutive securities consist primarily of the 2013 Equity Units for 2016 and 2015. See Note 17 for more information.

The 2014 Equity Units were excluded from the calculation of diluted EPS for the years ended December 31, 2016 and 2015, as the dilutive stock price threshold was not met. The 2016 Equity Units were excluded from the calculation of diluted EPS for the year ended December 31, 2017 and 2016, as the dilutive stock price threshold was not met. See Note 17 for more information. The Dominion Energy Midstream convertible preferred units are potentially dilutive securities but had no effect on the calculation of diluted EPS for the years ended December 31, 2017 and 2016. See Note 19 for more information.

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NOTE 9. INVESTMENTS

DOMINION ENERGY

Equity and Debt Securities

RABBI TRUST SECURITIES

Marketable equity and debt securities and cash equivalents held in Dominion Energy's rabbi trusts and classified as trading totaled $112 million and $104 million at December 31, 2017 and 2016, respectively.

DECOMMISSIONING TRUST SECURITIES

Dominion Energy holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Dominion Energy's decommissioning trust funds are summarized below:

(millions)	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
At December 31, 2017				
Marketable equity securities:				
U.S.	**$1,569**	**$1,857**	**$ —**	**$3,426**
Fixed income:				
Corporate debt instruments	**430**	**15**	**(1)**	**444**
Government securities	**1,039**	**27**	**(5)**	**1,061**
Common/collective trust funds	**60**	**—**	**—**	**60**
Cost method investments	**68**	**—**	**—**	**68**
Cash equivalents and other(2)	**34**	**—**	**—**	**34**
Total	**$3,200**	**$1,899**	**$ (6)(3)**	**$5,093**
At December 31, 2016				
Marketable equity securities:				
U.S.	$1,449	$1,408	$ —	$2,857
Fixed income:				
Corporate debt instruments	478	13	(4)	487
Government securities	978	22	(8)	992
Common/collective trust funds	67	—	—	67
Cost method investments	69	—	—	69
Cash equivalents and other(2)	12	—	—	12
Total	$3,053	$1,443	$(12)(3)	$4,484

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $5 million and $9 million at December 31, 2017 and 2016, respectively.
(3) The fair value of securities in an unrealized loss position was $565 million and $576 million at December 31, 2017 and 2016, respectively.

The fair value of Dominion Energy's marketable debt securities held in nuclear decommissioning trust funds at December 31, 2017 by contractual maturity is as follows:

(millions)	Amount
Due in one year or less	**$ 151**
Due after one year through five years	**385**
Due after five years through ten years	**370**
Due after ten years	**659**
Total	**$1,565**

Presented below is selected information regarding Dominion Energy's marketable equity and debt securities held in nuclear decommissioning trust funds:

Year Ended December 31, (millions)	2017	2016	2015
Proceeds from sales	**$1,831**	$1,422	$1,340
Realized gains(1)	**166**	128	219
Realized losses(1)	**71**	55	84

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

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Dominion Energy recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31,	2017	2016	2015
(millions)			
Total other-than-temporary impairment losses(1)	**$ 44**	$ 51	$ 66
Losses recorded to the nuclear decommissioning trust regulatory liability	**(16)**	(16)	(26)
Losses recognized in other comprehensive income (before taxes)	**(5)**	(12)	(9)
Net impairment losses recognized in earnings	**$ 23**	$ 23	$ 31

(1) Amounts include other-than-temporary impairment losses for debt securities of $5 million, $13 million and $9 million at December 31, 2017, 2016 and 2015, respectively.

VIRGINIA POWER

Virginia Power holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Virginia Power's decommissioning trust funds are summarized below:

	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
(millions)				
At December 31, 2017				
Marketable equity securities:				
U.S.	**$ 734**	**$831**	**$—**	**$1,565**
Fixed income:				
Corporate debt instruments	**216**	**8**	**—**	**224**
Government securities	**482**	**13**	**(2)**	**493**
Common/collective trust funds	**27**	**—**	**—**	**27**
Cost method investments	**68**	**—**	**—**	**68**
Cash equivalents and other(2)	**22**	**—**	**—**	**22**
Total	**$1,549**	**$852**	**$(2)(3)**	**$2,399**
At December 31, 2016				
Marketable equity securities:				
U.S.	$ 677	$624	$—	$1,301
Fixed income:				
Corporate debt instruments	274	6	(4)	276
Government securities	420	9	(2)	427
Common/collective trust funds	26	—	—	26
Cost method investments	69	—	—	69
Cash equivalents and other(2)	7	—	—	7
Total	$1,473	$639	$(6)(3)	$2,106

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $6 million and $7 million at December 31, 2017 and 2016, respectively.
(3) The fair value of securities in an unrealized loss position was $234 million and $287 million at December 31, 2017 and 2016, respectively.

The fair value of Virginia Power's marketable debt securities at December 31, 2017, by contractual maturity is as follows:

	Amount
(millions)	
Due in one year or less	**$ 32**
Due after one year through five years	**165**
Due after five years through ten years	**199**
Due after ten years	**348**
Total	**$744**

Presented below is selected information regarding Virginia Power's marketable equity and debt securities held in nuclear decommissioning trust funds.

Year Ended December 31,	2017	2016	2015
(millions)			
Proceeds from sales	**$849**	$733	$639
Realized gains(1)	**75**	63	110
Realized losses(1)	**30**	27	43

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

Virginia Power recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31,	2017	2016	2015
(millions)			
Total other-than-temporary impairment losses(1)	**$ 20**	$ 26	$ 36
Losses recorded to the nuclear decommissioning trust regulatory liability	**(16)**	(16)	(26)
Losses recognized in other comprehensive income (before taxes)	**(2)**	(7)	(6)
Net impairment losses recognized in earnings	**$ 2**	$ 3	$ 4

(1) Amounts include other-than-temporary impairment losses for debt securities of $2 million, $8 million and $6 million at December 31, 2017, 2016 and 2015, respectively.

Equity Method Investments

DOMINION ENERGY AND DOMINION ENERGY GAS

Investments that Dominion Energy and Dominion Energy Gas account for under the equity method of accounting are as follows:

Company	Ownership %	Investment Balance		Description
As of December 31,		2017	2016	
(millions)				
Dominion Energy				
Blue Racer	50%	**$ 691**	$ 677	Midstream gas and related services
Iroquois	50%(1)	**311**	316	Gas transmission system
Atlantic Coast Pipeline	48%	**382**	256	Gas transmission system
Fowler Ridge	50%	**81**	116	Wind-powered merchant generation facility
NedPower	50%	**—(2)**	112	Wind-powered merchant generation facility
Other	various	**79**	84	
Total		**$1,544**	$1,561	
Dominion Energy Gas				
Iroquois	24.07%	**$ 95**	$ 98	Gas transmission system
Total		**$ 95**	$ 98	

(1) Comprised of Dominion Energy Midstream's interest of 25.93% and Dominion Energy Gas' interest of 24.07%. See Note 15 for more information.

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(2) Liability of $17 million associated with NedPower recorded to other deferred credits and other liabilities, on the Consolidated Balance Sheets as of December 31, 2017. See additional discussion of NedPower below.

Dominion Energy's equity earnings on its investments totaled $14 million, $111 million and $56 million in 2017, 2016 and 2015, respectively, included in other income in Dominion Energy's Consolidated Statements of Income. Dominion Energy received distributions from these investments of $419 million, $104 million and $83 million in 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, the carrying amount of Dominion Energy's investments exceeded its share of underlying equity in net assets by $249 million and $260 million, respectively. These differences are comprised at both December 31, 2017 and 2016 of $176 million, reflecting equity method goodwill that is not being amortized and at December 31, 2017 and 2016, of $73 million and $84 million related to basis differences from Dominion Energy's investments in Blue Racer and wind projects, which are being amortized over the useful lives of the underlying assets, and in Atlantic Coast Pipeline, which is being amortized over the term of the credit facility.

Dominion Energy Gas' equity earnings on its investment totaled $21 million in 2017 and 2016 and $23 million in 2015. Dominion Energy Gas received distributions from its investment of $24 million, $22 million and $28 million in 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, the carrying amount of Dominion Energy Gas' investment exceeded its share of underlying equity in net assets by $8 million. The difference reflects equity method goodwill and is not being amortized. In May 2016, Dominion Energy Gas sold 0.65% of the noncontrolling partnership interest in Iroquois to TransCanada for approximately $7 million, which resulted in a $5 million ($3 million after-tax) gain, included in other income in Dominion Energy Gas' Consolidated Statements of Income.

DOMINION ENERGY

BLUE RACER

In December 2012, Dominion Energy formed a joint venture with Caiman to provide midstream services to natural gas producers operating in the Utica Shale region in Ohio and portions of Pennsylvania. Blue Racer is an equal partnership between Dominion Energy and Caiman, with Dominion Energy contributing midstream assets and Caiman contributing private equity capital.

In December 2016, Dominion Energy Gas repurchased a portion of the Western System from Blue Racer for $10 million, which is included in property, plant and equipment in Dominion Energy Gas' Consolidated Balance Sheets.

ATLANTIC COAST PIPELINE

In September 2014, Dominion Energy, along with Duke and Southern Company Gas, announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion Energy an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion Energy purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. As of December 31, 2017, the members hold the following membership interests: Dominion Energy, 48%; Duke, 47%; and Southern Company Gas, 5%.

Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina. Subsidiaries and affiliates of all three members plan to be customers of the pipeline under 20-year contracts. Public Service Company of North Carolina, Inc. also plans to be a customer of the pipeline under a 20-year contract. Atlantic Coast Pipeline is considered an equity method investment as Dominion Energy has the ability to exercise significant influence, but not control, over the investee. See Note 15 for more information.

DETI provides services to Atlantic Coast Pipeline which totaled $129 million, $95 million and $74 million in 2017, 2016 and 2015, respectively, included in operating revenue in Dominion Energy and Dominion Energy Gas' Consolidated Statements of Income. Amounts receivable related to these services were $12 million and $10 million at December 31, 2017 and 2016, respectively, composed entirely of accrued unbilled revenue, included in other receivables in Dominion Energy and Dominion Energy Gas' Consolidated Balance Sheets.

In October 2017, Dominion Energy entered into a guarantee agreement to support a portion of Atlantic Coast Pipeline's obligation under its credit facility. See Note 22 for more information.

Dominion Energy contributed $310 million, $184 million and $38 million during 2017, 2016 and 2015, respectively, to Atlantic Coast Pipeline.

Dominion Energy received distributions of $270 million in 2017 from Atlantic Coast Pipeline. No distributions were received in 2016 or 2015.

FOWLER RIDGE & NEDPOWER

In the fourth quarter of 2017, Dominion Energy recorded a charge of $126 million ($76 million after-tax) in other income in its Consolidated Statements of Income reflecting its share of a long-lived asset impairment of property, plant and equipment recorded by NedPower, which resulted in losses in excess of Dominion Energy's investment balance. Dominion Energy recorded the excess losses due to its commitment to provide further financial support for NedPower, resulting in a liability of $17 million recorded to other deferred credits and other liabilities, on the Consolidated Balance Sheets.

As a result of the impairment recorded by NedPower, Dominion Energy evaluated its equity method investment in Fowler Ridge, a similar wind-powered merchant generation facility, determined its fair value was other than-temporarily impaired and recorded an impairment charge of $32 million ($20 million after-tax) in other income in its Consolidated Statements of Income. The fair value of $81 million was estimated using a discounted cash flow method and is considered a Level 3 fair value measurement due to the use of significant unobservable inputs related to the timing and amount of future equity distributions based on the investee's future wind generation and operating costs.

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NOTE 10. PROPERTY, PLANT AND EQUIPMENT

Major classes of property, plant and equipment and their respective balances for the Companies are as follows:

At December 31,	2017	2016
(millions)		
Dominion Energy		
Utility:		
Generation	**$17,602**	$17,147
Transmission	**15,335**	14,315
Distribution	**17,408**	16,381
Storage	**2,887**	2,814
Nuclear fuel	**1,599**	1,537
Gas gathering and processing	**219**	216
Oil and gas	**1,720**	1,652
General and other	**1,514**	1,450
Plant under construction	**7,765**	6,254
Total utility	**66,049**	61,766
Nonutility:		
Merchant generation-nuclear	**1,452**	1,419
Merchant generation-other	**4,992**	4,149
Nuclear fuel	**968**	897
Gas gathering and processing	**630**	619
Other-including plant under construction	**732**	706
Total nonutility	**8,774**	7,790
Total property, plant and equipment	**$74,823**	$69,556
Virginia Power		
Utility:		
Generation	**$17,602**	$17,147
Transmission	**8,332**	7,871
Distribution	**11,151**	10,573
Nuclear fuel	**1,599**	1,537
General and other	**794**	745
Plant under construction	**2,840**	2,146
Total utility	**42,318**	40,019
Nonutility-other	**11**	11
Total property, plant and equipment	**$42,329**	$40,030
Dominion Energy Gas		
Utility:		
Transmission	**$ 4,732**	$ 4,231
Distribution	**3,267**	3,019
Storage	**1,688**	1,627
Gas gathering and processing	**202**	198
General and other	**216**	184
Plant under construction	**293**	448
Total utility	**10,398**	9,707
Nonutility:		
Gas gathering and processing	**630**	$ 619
Other-including plant under construction	**145**	149
Total nonutility	**775**	768
Total property, plant and equipment	**$11,173**	$10,475

DOMINION ENERGY AND VIRGINIA POWER

Jointly-Owned Power Stations

Dominion Energy's and Virginia Power's proportionate share of jointly-owned power stations at December 31, 2017 is as follows:

	Bath County Pumped Storage Station(1)	North Anna Units 1 and 2(1)	Clover Power Station(1)	Millstone Unit 3(2)
(millions, except percentages)				
Ownership interest	**60%**	**88.4%**	**50%**	**93.5%**
Plant in service	**$1,059**	**$ 2,504**	**$ 589**	**$1,217**
Accumulated depreciation	**(612)**	**(1,263)**	**(231)**	**(381)**
Nuclear fuel	**—**	**745**	**—**	**552**
Accumulated amortization of nuclear fuel	**—**	**(607)**	**—**	**(427)**
Plant under construction	**2**	**92**	**6**	**68**

(1) Units jointly owned by Virginia Power.
(2) Unit jointly owned by Dominion Energy.

The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly-owned facilities in the same proportion as their respective ownership interest. Dominion Energy and Virginia Power report their share of operating costs in the appropriate operating expense (electric fuel and other energy-related purchases, other operations and maintenance, depreciation, depletion and amortization and other taxes, etc.) in the Consolidated Statements of Income.

Acquisition of Solar Projects

In September 2017, Virginia Power entered into agreements to acquire two solar development projects in North Carolina. The first acquisition is expected to close prior to the project commencing commercial operations, which is expected by the end of 2018, and cost approximately $140 million once constructed, including the initial acquisition cost. The second acquisition is expected to close prior to the project commencing commercial operations, which is expected by the end of 2019, and cost approximately $140 million once constructed, including the initial acquisition cost. The projects are expected to generate approximately 155 MW combined. Virginia Power anticipates claiming federal investment tax credits on these solar projects.

Assignment of Tower Rental Portfolio

Virginia Power rents space on certain of its electric transmission towers to various wireless carriers for communications antennas and other equipment. In March 2017, Virginia Power sold its rental portfolio to Vertical Bridge Towers II, LLC for $91 million in cash. The proceeds are subject to Virginia Power's FERC-regulated tariff, under which it is required to return half of the proceeds to customers. Virginia Power recognized $11 million during 2017, with the remaining $35 million to be recognized ratably through 2023.

DOMINION ENERGY AND DOMINION ENERGY GAS

Assignments of Shale Development Rights

In December 2013, Dominion Energy Gas closed on agreements with two natural gas producers to convey over time approximately 100,000 acres of Marcellus Shale development rights underneath several of its natural gas storage fields. The agreements provide for payments to Dominion Energy Gas, subject to customary

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adjustments, of approximately $200 million over a period of nine years, and an overriding royalty interest in gas produced from the acreage. In 2013, Dominion Energy Gas received approximately $100 million in cash proceeds. In 2014, Dominion Energy Gas received $16 million in additional cash proceeds resulting from post-closing adjustments. In March 2015, Dominion Energy Gas and one of the natural gas producers closed on an amendment to the agreement, which included the immediate conveyance of approximately 9,000 acres of Marcellus Shale development rights and a two-year extension of the term of the original agreement. The conveyance of development rights resulted in the recognition of $43 million ($27 million after-tax) of previously deferred revenue to operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income. In April 2016, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the immediate conveyance of a 32% partial interest in the remaining approximately 70,000 acres. This conveyance resulted in the recognition of the remaining $35 million ($21 million after-tax) of previously deferred revenue to operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income. In August 2017, Dominion Energy Gas and the natural gas producer signed an amendment to the agreement, which included the finalization of contractual matters on previous conveyances, the conveyance of Dominion Energy Gas' remaining 68% interest in approximately 70,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage. Dominion Energy Gas will receive total consideration of $130 million, with $65 million received in 2017 and $65 million to be received by the end of the third quarter of 2018 in connection with the final conveyance. As a result of this amendment, in 2017, Dominion Energy Gas recognized a $56 million ($33 million after-tax) gain included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income associated with the finalization of the contractual matters on previous conveyances, a $9 million ($5 million after-tax) gain included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income associated with the elimination of its overriding royalty interest and expects to recognize an approximately $65 million ($47 million after-tax) gain associated with the final conveyance of acreage.

In November 2014, Dominion Energy Gas closed an agreement with a natural gas producer to convey over time approximately 24,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields. The agreement provided for payments to Dominion Energy Gas, subject to customary adjustments, of approximately $120 million over a period of four years, and an overriding royalty interest in gas produced from the acreage. In November 2014, Dominion Energy Gas closed on the agreement and received proceeds of $60 million associated with an initial conveyance of approximately 12,000 acres. In connection with that agreement, in 2016, Dominion Energy Gas conveyed a 50% interest in approximately 4,000 acres of Marcellus Shale development rights and received proceeds of $10 million and an overriding royalty interest in gas produced from the acreage. These transactions resulted in a $10 million ($6 million after-tax) gain. In July 2017, in connection with the existing agreement, Dominion Energy Gas conveyed an additional 50% interest in approximately 2,000 acres of Marcellus Shale development rights and received proceeds of $5 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in a $5 million ($3 million after-tax) gain. The gains are included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income. In January 2018, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the conveyance of Dominion Energy Gas' remaining 50% interest in approximately 18,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage. Dominion Energy Gas received proceeds of $28 million, resulting in an approximately $28 million ($20 million after-tax) gain recorded in the first quarter of 2018.

In March 2015, Dominion Energy Gas conveyed to a natural gas producer approximately 11,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields and received proceeds of $27 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in a $27 million ($16 million after-tax) gain, included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income.

In September 2015, Dominion Energy Gas closed on an agreement with a natural gas producer to convey approximately 16,000 acres of Utica and Point Pleasant Shale development rights underneath one of its natural gas storage fields. The agreement provided for a payment to Dominion Energy Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage. In September 2015, Dominion Energy Gas received proceeds of $52 million associated with the conveyance of the acreage, resulting in a $52 million ($29 million after-tax) gain, included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income.

DOMINION ENERGY

Sale of Certain Retail Energy Marketing Assets

In October 2017, Dominion Energy entered into an agreement to sell certain assets associated with its nonregulated retail energy marketing operations for total consideration of $143 million, subject to customary approvals and certain adjustments. In December 2017, the first phase of the agreement closed for $79 million, which resulted in the recognition of a $78 million ($48 million after-tax) benefit, included in other operations and maintenance expense in Dominion Energy's Consolidated Statements of Income. Dominion Energy is expected to recognize a benefit of approximately $65 million ($48 million after-tax) in other operations and maintenance expense upon closing of the second phase of the agreement in 2018. Pursuant to the agreement, Dominion Energy entered into a commission agreement with the buyer upon the first closing in December 2017 under which the buyer will pay a commission in connection with the right to use Dominion Energy's brand in marketing materials and other services over a ten-year term.

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NOTE 11. GOODWILL AND INTANGIBLE ASSETS

Goodwill

The changes in Dominion Energy's and Dominion Energy Gas' carrying amount and segment allocation of goodwill are presented below:

(millions)	Power Generation	Gas Infrastructure	Power Delivery	Corporate and Other(1)	Total
Dominion Energy					
Balance at December 31, 2015(2)	$1,422	$ 946	$926	$—	$3,294
Dominion Energy Questar Combination	—	3,105(3)	—	—	3,105
Balance at December 31, 2016(2)	$1,422	$4,051	$926	$—	$6,399
Dominion Energy Questar Combination	—	6(3)	—	—	6
Balance at December 31, 2017(2)	**$1,422**	**$4,057**	**$926**	**$—**	**$6,405**
Dominion Energy Gas					
Balance at December 31, 2015(2)	$ —	$ 542	$ —	$—	$ 542
No events affecting goodwill	—	—	—	—	—
Balance at December 31, 2016(2)	$ —	$ 542	$ —	$—	$ 542
No events affecting goodwill	—	—	—	—	—
Balance at December 31, 2017(2)	**$ —**	**$ 542**	**$ —**	**$—**	**$ 542**

(1) Goodwill recorded at the Corporate and Other segment is allocated to the primary operating segments for goodwill impairment testing purposes.
(2) Goodwill amounts do not contain any accumulated impairment losses.
(3) See Note 3.

Other Intangible Assets

The Companies' other intangible assets are subject to amortization over their estimated useful lives. Dominion Energy's amortization expense for intangible assets was $80 million, $73 million and $78 million for 2017, 2016 and 2015, respectively. In 2017, Dominion Energy acquired $147 million of intangible assets, primarily representing software and right-of-use assets, with an estimated weighted-average amortization period of approximately 14 years. Amortization expense for Virginia Power's intangible assets was $31 million, $29 million and $25 million for 2017, 2016 and 2015, respectively. In 2017, Virginia Power acquired $39 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of 7 years. Dominion Energy Gas' amortization expense for intangible assets was $14 million, $6 million and $18 million for 2017, 2016 and 2015, respectively. In 2017, Dominion Energy Gas acquired $25 million of intangible assets, primarily representing software and right-of-use assets, with an estimated weighted-average amortization period of approximately 14 years. The components of intangible assets are as follows:

At December 31,	**2017**		2016	
(millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Dominion Energy				
Software, licenses and other	**$1,043**	**$358**	$955	$337
Virginia Power				
Software, licenses and other	**$ 347**	**$114**	$326	$101
Dominion Energy Gas				
Software, licenses and other	**$ 165**	**$ 56**	$147	$ 49

Annual amortization expense for these intangible assets is estimated to be as follows:

(millions)	2018	2019	2020	2021	2022
Dominion Energy	**$78**	**$68**	**$56**	**$43**	**$37**
Virginia Power	**$30**	**$26**	**$20**	**$13**	**$ 9**
Dominion Energy Gas	**$13**	**$13**	**$12**	**$11**	**$10**

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NOTE 12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities include the following:

At December 31, (millions)	2017	2016
Dominion Energy		
Regulatory assets:		
Deferred rate adjustment clause costs(1)	$ 70	$ 63
Deferred nuclear refueling outage costs(2)	54	71
Unrecovered gas costs(3)	38	19
Deferred cost of fuel used in electric generation(4)	23	—
Other	109	91
Regulatory assets-current	294	244
Unrecognized pension and other postretirement benefit costs(5)	1,336	1,401
Deferred rate adjustment clause costs(1)	401	329
Derivatives(6)	223	174
PJM transmission rates(7)	222	192
Utility reform legislation(8)	147	99
Income taxes recoverable through future rates(9)	32	123
Other	119	155
Regulatory assets-noncurrent	2,480	2,473
Total regulatory assets	$2,774	$2,717
Regulatory liabilities:		
Provision for future cost of removal and AROs(10)	$ 101	$ —
PIPP(11)	20	28
Deferred cost of fuel used in electric generation(4)	8	61
Other	64	74
Regulatory liabilities-current(12)	193	163
Income taxes refundable through future rates(13)	4,058	—
Provision for future cost of removal and AROs(10)	1,384	1,427
Nuclear decommissioning trust(14)	1,121	902
Derivatives(6)	69	69
Other	284	224
Regulatory liabilities-noncurrent	6,916	2,622
Total regulatory liabilities	$7,109	$2,785
Virginia Power		
Regulatory assets:		
Deferred rate adjustment clause costs(1)	$ 56	$ 51
Deferred nuclear refueling outage costs(2)	54	71
Deferred cost of fuel used in electric generation(4)	23	—
Other	72	57
Regulatory assets-current	205	179
Deferred rate adjustment clause costs(1)	312	246
PJM transmission rates(7)	222	192
Derivatives(6)	190	133
Income taxes recoverable through future rates(9)	—	76
Other	86	123
Regulatory assets-noncurrent	810	770
Total regulatory assets	$1,015	$ 949
Regulatory liabilities:		
Provision for future cost of removal(10)	$ 80	$ —
Deferred cost of fuel used in electric generation(4)	8	61
Other	39	54
Regulatory liabilities-current(12)	127	115
Income taxes refundable through future rates(13)	2,581	—
Nuclear decommissioning trust(14)	1,121	902
Provision for future cost of removal(10)	915	946
Derivatives(6)	69	69
Other	74	45
Regulatory liabilities-noncurrent	4,760	1,962
Total regulatory liabilities	$4,887	$2,077

At December 31, (millions)	2017	2016
Dominion Energy Gas		
Regulatory assets:		
Deferred rate adjustment clause costs(1)	$ 14	$ 12
Unrecovered gas costs(3)	8	12
Other	4	2
Regulatory assets-current(15)	26	26
Unrecognized pension and other postretirement benefit costs(5)	258	358
Utility reform legislation(8)	147	99
Deferred rate adjustment clause costs(1)	89	79
Income taxes recoverable through future rates(9)	—	23
Other	17	18
Regulatory assets-noncurrent	511	577
Total regulatory assets	$ 537	$603
Regulatory liabilities:		
PIPP(11)	$ 20	$ 28
Provision for future cost of removal and AROs(10)	13	—
Other	5	7
Regulatory liabilities-current(12)	38	35
Income taxes refundable through future rates(13)	998	—
Provision for future cost of removal and AROs(10)	160	174
Other	69	45
Regulatory liabilities-noncurrent	1,227	219
Total regulatory liabilities	$1,265	$254

(1) Primarily reflects deferrals under the electric transmission FERC formula rate and the deferral of costs associated with certain current and prospective rider projects for Virginia Power and deferrals of costs associated with certain current and prospective rider projects for Dominion Energy Gas. See Note 13 for more information.

(2) Legislation enacted in Virginia in April 2014 requires Virginia Power to defer operation and maintenance costs incurred in connection with the refueling of any nuclear-powered generating plant. These deferred costs will be amortized over the refueling cycle, not to exceed 18 months.

(3) Reflects unrecovered gas costs at regulated gas operations, which are recovered through filings with the applicable regulatory authority.

(4) Reflects deferred fuel expenses for the Virginia and North Carolina jurisdictions of Dominion Energy's and Virginia Power's generation operations. See Note 13 for more information.

(5) Represents unrecognized pension and other postretirement employee benefit costs expected to be recovered through future rates generally over the expected remaining service period of plan participants by certain of Dominion Energy's and Dominion Energy Gas' rate-regulated subsidiaries.

(6) As discussed under Derivative Instruments in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities as they are expected to be recovered from or refunded to customers.

(7) Reflects amount related to the PJM transmission cost allocation matter. See Note 13 for more information.

(8) Ohio legislation under House Bill 95, which became effective in September 2011. This law updates natural gas legislation by enabling gas companies to include more up-to-date cost levels when filing rate cases. It also allows gas companies to seek approval of capital expenditure plans under which gas companies can recognize carrying costs on associated capital investments placed in service and can defer the carrying costs plus depreciation and property tax expenses for recovery from ratepayers in the future.

(9) Amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes. See below for discussion of the 2017 Tax Reform Act.

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(10) Rates charged to customers by the Companies' regulated businesses include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.
(11) Under PIPP, eligible customers can make reduced payments based on their ability to pay. The difference between the customer's total bill and the PIPP plan amount is deferred and collected or returned annually under the PIPP rate adjustment clause according to East Ohio tariff provisions. See Note 13 for more information.
(12) Current regulatory liabilities are presented in other current liabilities in the Consolidated Balance Sheets of the Companies.
(13) Amounts recorded to pass the effect of reduced income tax rates from the 2017 Tax Reform Act to customers in future periods, which will reverse at the weighted average tax rate that was used to build the reserves over the remaining book life of the property, net of amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity.
(14) Primarily reflects a regulatory liability representing amounts collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of Virginia Power's utility nuclear generation stations, in excess of the related AROs.
(15) Current regulatory assets are presented in other current assets in the Consolidated Balance Sheets of Dominion Energy Gas.

At December 31, 2017, $390 million of Dominion Energy's, $273 million of Virginia Power's and $11 million of Dominion Energy Gas' regulatory assets represented past expenditures on which they do not currently earn a return. With the exception of the $222 million PJM transmission cost allocation matter, the majority of these expenditures are expected to be recovered within the next two years.

NOTE 13. REGULATORY MATTERS

Regulatory Matters Involving Potential Loss Contingencies

As a result of issues generated in the ordinary course of business, the Companies are involved in various regulatory matters. Certain regulatory matters may ultimately result in a loss; however, as such matters are in an initial procedural phase, involve uncertainty as to the outcome of pending reviews or orders, and/or involve significant factual issues that need to be resolved, it is not possible for the Companies to estimate a range of possible loss. For matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the regulatory process such that the Companies are able to estimate a range of possible loss. For regulatory matters for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any estimated range is based on currently available information, involves elements of judgment and significant uncertainties and may not represent the Companies' maximum possible loss exposure. The circumstances of such regulatory matters will change from time to time and actual results may vary significantly from the current estimate. For current matters not specifically reported below, management does not anticipate that the outcome from such matters would have a material effect on the Companies' financial position, liquidity or results of operations.

FERC—ELECTRIC

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Dominion Energy's merchant generators sell electricity in the PJM, MISO, CAISO and ISO-NE wholesale markets, and to wholesale purchasers in the states of Virginia, North Carolina, Indiana, Connecticut, Tennessee, Georgia, California, South Carolina and Utah, under Dominion Energy's market-based sales tariffs authorized by FERC or pursuant to FERC authority to sell as a qualified facility. Virginia Power purchases and, under its FERC market-based rate authority, sells electricity in the wholesale market. In addition, Virginia Power has FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside Virginia Power's service territory. Any such sales would be voluntary.

Rates

In April 2008, FERC granted an application for Virginia Power's electric transmission operations to establish a forward-looking formula rate mechanism that updates transmission rates on an annual basis and approved an ROE of 11.4%, effective as of January 1, 2008. The formula rate is designed to recover the expected revenue requirement for each calendar year and is updated based on actual costs. The FERC-approved formula method, which is based on projected costs, allows Virginia Power to earn a current return on its growing investment in electric transmission infrastructure.

In March 2010, ODEC and North Carolina Electric Membership Corporation filed a complaint with FERC against Virginia Power claiming, among other issues, that the incremental costs of undergrounding certain transmission line projects were unjust, unreasonable and unduly discriminatory or preferential and should be excluded from Virginia Power's transmission formula rate. A settlement of the other issues raised in the complaint was approved by FERC in May 2012.

In March 2014, FERC issued an order excluding from Virginia Power's transmission rates for wholesale transmission customers located outside Virginia the incremental costs of undergrounding certain transmission line projects. FERC found it is not just and reasonable for non-Virginia wholesale transmission customers to be allocated the incremental costs of undergrounding the facilities because the projects are a direct result of Virginia legislation and Virginia Commission pilot programs intended to benefit the citizens of Virginia. The order is retroactively effective as of March 2010 and will cause the reallocation of the costs charged to wholesale transmission customers with loads outside Virginia to wholesale transmission customers with loads in Virginia. FERC determined that there was not sufficient evidence on the record to determine the magnitude of the underground increment and held a hearing to determine the appropriate amount of undergrounding cost to be allocated to each wholesale transmission customer in Virginia.

In October 2017, FERC issued an order determining the calculation of the incremental costs of undergrounding the transmission projects and affirming that the costs are to be recovered from the wholesale transmission customers with loads located in Virginia. FERC directed Virginia Power to rebill all wholesale transmission customers retroactively to March 2010 within 30 days of when the proceeding becomes final and no longer subject to rehearing. In November 2017, Virginia Power, North Carolina Electric Membership Corporation and the whole-

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sale transmission customers filed petitions for rehearing. While Virginia Power cannot predict the outcome of the matter, it is not expected to have a material effect on results of operations.

PJM Transmission Rates
In April 2007, FERC issued an order regarding its transmission rate design for the allocation of costs among PJM transmission customers, including Virginia Power, for transmission service provided by PJM. For new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a PJM regional rate design where customers pay according to each customer's share of the region's load. For recovery of costs of existing facilities, FERC approved the existing methodology whereby a customer pays the cost of facilities located in the same zone as the customer. A number of parties appealed the order to the U.S. Court of Appeals for the Seventh Circuit.

In August 2009, the court issued its decision affirming the FERC order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above for further consideration by FERC. On remand, FERC reaffirmed its earlier decision to allocate the costs of new facilities 500 kV and above according to the customer's share of the region's load. A number of parties filed appeals of the order to the U.S. Court of Appeals for the Seventh Circuit. In June 2014, the court again remanded the cost allocation issue to FERC. In December 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the cost allocation issue. The hearing only concerns the costs of new facilities approved by PJM prior to February 1, 2013. Transmission facilities approved after February 1, 2013 are allocated on a hybrid cost allocation method approved by FERC and not subject to any court review.

In June 2016, PJM, the PJM transmission owners and state commissions representing substantially all of the load in the PJM market submitted a settlement to FERC to resolve the outstanding issues regarding this matter. Under the terms of the settlement, Virginia Power would be required to pay approximately $200 million to PJM over the next 10 years. Although the settlement agreement has not been accepted by FERC, and the settlement is opposed by a small group of parties to the proceeding, Virginia Power believes it is probable it will be required to make payment as an outcome of the settlement. Accordingly, as of December 31, 2017, Virginia Power has a contingent liability of $231 million in other deferred credits and other liabilities, which is offset by a $222 million regulatory asset for the amount that will be recovered through retail rates in Virginia.

FERC—GAS
In July 2017, FERC audit staff communicated to DETI that it had substantially completed an audit of DETI's compliance with the accounting and reporting requirements of FERC's Uniform System of Accounts and provided a description of matters and preliminary recommendations. In November 2017, the FERC audit staff issued its audit report which could have the potential to result in adjustments which could be material to Dominion Energy and Dominion Energy Gas' results of operations. In December 2017, DETI provided its response to the audit report. DETI requested FERC review of contested findings and submitted its plan for compliance with the uncontested portions of the report. In connection with one uncontested issue, DETI recognized a charge of $15 million ($9 million after-tax) recorded within other operations and maintenance expense in Dominion Energy's and Dominion Energy Gas' Consolidated Statements of Income during 2017 to write-off the balance of a regulatory asset, originally established in 2008, that is no longer considered probable of recovery. Pending final resolution of the audit process and a determination by FERC, management is unable to estimate the potential impact of the other findings and no amounts have been recognized.

2017 TAX REFORM ACT
Subsequent to the enactment of the 2017 Tax Reform Act, the Companies' state regulators issued orders requesting that public utilities evaluate the total tax impact on the entity's cost of service and accrue a regulatory liability attributable to the benefits of the reduction in the corporate income tax rate. Certain of the orders requested that the public utilities submit a response to the state regulatory commissions detailing the total tax impact on the utility's cost of service.

Virginia Power submitted a response to the North Carolina Commission detailing the impact of the 2017 Tax Reform Act on base non-fuel cost of service and Virginia Power's excess deferred income taxes clarifying that the amounts have been deferred to a regulatory liability. Questar Gas submitted a response to the Utah Commission detailing the impact of the 2017 Tax Reform Act on base rates and the infrastructure rider, and proposing that the benefits be passed back to customers. These filings are pending. Dominion Energy plans to respond to the remaining state regulatory commissions in accordance with the due dates on the issued orders. The Companies will begin to reserve the impacts of the cost of service reduction as a regulatory liability beginning in 2018 until the rates are reset.

To date, the FERC has not issued guidance on how and when to reflect the impacts of the 2017 Tax Reform Act in customer rates.

The Companies have recorded a reasonable estimate of net income taxes refundable through future rates in the jurisdictions in which they operate. Through actions by FERC or state regulators the estimates may be subject to changes that could have a material impact on the Companies' results of operations, financial condition and/or cash flows.

Other Regulatory Matters

ELECTRIC REGULATION IN VIRGINIA
The Regulation Act enacted in 2007 instituted a cost-of-service rate model, ending Virginia's planned transition to retail competition for electric supply service to most classes of customers.

The Regulation Act authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, FERC-approved transmission costs, underground distribution lines, environmental compliance, conservation and energy efficiency programs and renewable energy programs, and also contains statutory provisions directing Virginia Power to file annual fuel cost recovery cases with the Virginia Commission. As amended, it provides for enhanced returns on capital expenditures on specific newly-proposed generation projects.

If the Virginia Commission's future rate decisions, including actions relating to Virginia Power's rate adjustment clause filings,

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differ materially from Virginia Power's expectations, it may adversely affect its results of operations, financial condition and cash flows.

Regulation Act Legislation
In February 2015, the Virginia Governor signed legislation into law which will keep Virginia Power's base rates unchanged until at least December 1, 2022. In addition, no biennial reviews will be conducted by the Virginia Commission for the five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. The legislation states that Virginia Power's 2015 biennial review, filed in March 2015, would proceed for the sole purpose of reviewing and determining whether any refunds are due to customers based on earnings performance for generation and distribution services during the 2013 and 2014 test periods. In addition, the legislation requires the Virginia Commission to conduct proceedings in 2017 and 2019 to determine the utility's ROE for use in connection with rate adjustment clauses and requires utilities to file integrated resource plans annually rather than biennially. In November 2015, the Virginia Commission ordered testimony, briefs and a separate bifurcated hearing in Virginia Power's then-pending Rider B, R, S, and W cases on whether the Virginia Commission can adjust the ROE applicable to these rate adjustment clauses prior to 2017. In February 2016, the Virginia Commission issued final orders in these cases, stating that it could adjust the ROE for the projects. After separate, additional bifurcated hearings, the Virginia Commission issued final orders setting base ROEs for the Rider GV, C1A and C2A, BW, US-2 and U cases.

In February 2016, certain industrial customers of APCo petitioned the Virginia Commission to issue a declaratory judgment that Virginia legislation enacted in 2015 keeping APCo's base rates unchanged until at least 2020 (and Virginia Power's base rates unchanged until at least 2022) is unconstitutional, and to require APCo to make biennial review filings in 2016 and 2018. Virginia Power intervened to support the constitutionality of this legislation. In July 2016, the Virginia Commission held in a divided opinion that this legislation is constitutional, and the industrial customers appealed this order to the Supreme Court of Virginia. In November 2016, the Supreme Court of Virginia granted the appeal as a matter of right and consolidated it for oral argument with other similar appeals from the Virginia Commission's order. In September 2017, the Supreme Court of Virginia affirmed that the legislation is constitutional.

In March 2017, as required by Regulation Act legislation enacted in February 2015, Virginia Power filed an application for the Virginia Commission to determine the general ROE for Virginia Power's non-transmission rate adjustment clauses. The application supported a 10.5% ROE for these rate adjustment clauses. In November 2017, the Virginia Commission approved a general 9.2% ROE for these rate adjustment clauses.

2015 Biennial Review
In November 2015, the Virginia Commission issued the 2015 Biennial Review Order. After deciding several contested regulatory earnings adjustments, the Virginia Commission ruled that Virginia Power earned on average an ROE of approximately 10.89% on its generation and distribution services for the combined 2013 and 2014 test periods. Because this ROE was more than 70 basis points above Virginia Power's authorized ROE of 10.0%, the Virginia Commission ordered that approximately $20 million in excess earnings be credited to customer bills based on usage in 2013 and 2014 over a six-month period beginning within 60 days of the 2015 Biennial Review Order.

Virginia Fuel Expenses
In May 2017, Virginia Power submitted its annual fuel factor to the Virginia Commission to recover an estimated $1.6 billion in Virginia jurisdictional projected fuel expenses for the rate year beginning July 1, 2017. Virginia Power's proposed fuel rate represented a fuel revenue increase of $279 million when applied to projected kilowatt-hour sales for the period July 1, 2017 to June 30, 2018. In June 2017, the Virginia Commission approved Virginia Power's proposed fuel rate.

Solar Facility Projects
In February 2017, Virginia Power received approval from the Virginia Commission for a CPCN to construct and operate the Remington solar facility and related distribution interconnection facilities. The 20 MW facility began operations in October 2017 at a total cost of $45 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, compensates Virginia Power for the facility's net electrical energy output, and Microsoft Corporation purchases all environmental attributes (including renewable energy certificates) generated by the facility. There is no rate adjustment clause associated with this CPCN, nor will any costs of the project be recovered from jurisdictional customers.

In March 2017, Virginia Power received Virginia Commission approval for a CPCN to construct and operate the Oceana solar facility and related distribution interconnection facilities. The 18 MW facility began operations in December 2017 at a total cost of $40 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, compensates Virginia Power for the facility's net electrical energy output. Virginia Power will retire renewable energy certificates on the Commonwealth of Virginia's behalf in an amount equal to those generated by the facility. There is no rate adjustment clause associated with the facility, nor will any of its costs be recovered from jurisdictional customers.

Rate Adjustment Clauses
Below is a discussion of significant riders associated with various Virginia Power projects:

- The Virginia Commission previously approved Rider T1 concerning transmission rates. In May 2017, Virginia Power proposed a $625 million total revenue requirement consisting of $490 million for the transmission component of Virginia Power's base rates and $135 million for Rider T1. This total revenue requirement represents a $55 million decrease versus the revenues to be produced during the rate year under current rates. In July 2017, the Virginia Commission approved the proposed total revenue requirement, including Rider T1, subject to true-up, for the rate year beginning September 1, 2017.

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- The Virginia Commission previously approved Rider S in conjunction with the Virginia City Hybrid Energy Center. In February 2017, the Virginia Commission approved a $243 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 10.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved a $218 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 10.2% base ROE effective April 1, 2018.
- The Virginia Commission previously approved Rider W in conjunction with Warren County. In February 2017, the Virginia Commission approved a $121 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 10.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved a $109 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 10.2% ROE for Rider W effective April 1, 2018.
- The Virginia Commission previously approved Rider R in conjunction with Bear Garden. In February 2017, the Virginia Commission approved a $72 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 10.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved a $66 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 10.2% ROE for Rider R effective April 1, 2018.
- The Virginia Commission previously approved Rider B in conjunction with the conversion of three power stations to biomass. In February 2017, the Virginia Commission approved a $27 million revenue requirement for the rate year beginning April 1, 2017. It also established an 11.4% ROE effective April 1, 2017. In June 2017, Virginia Power proposed a $42 million revenue requirement for the rate year beginning April 1, 2018, which represents a $15 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider U in conjunction with cost recovery to move certain electric distribution facilities underground as authorized by prior Virginia legislation. In September 2017, the Virginia Commission approved a total $22 million annual revenue requirement effective October 1, 2017, using a 9.4% ROE, and a total capital investment of $40 million for second phase conversions.
- The Virginia Commission previously approved Riders C1A and C2A in connection with cost recovery for DSM programs. In June 2017, the Virginia Commission approved a $28 million revenue requirement, subject to true-up, for the rate year beginning July 1, 2017. It also established a 9.4% ROE for Riders C1A and C2A effective July 1, 2017. In October 2017, Virginia Power requested approval to extend one existing energy efficiency program for five years with a new $25 million cost cap, and proposed a total $31 million revenue requirement for the rate year beginning July 1, 2018, which represents a $3 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider BW in conjunction with Brunswick County. In April 2017, the Virginia Commission established a 10.4% ROE for Rider BW effective September 1, 2017. In June 2017, it approved a $127 million revenue requirement, subject to true-up, for the rate year beginning September 1, 2017. In October 2017, Virginia Power proposed a $132 million revenue requirement for the rate year beginning September 1, 2018, which represents a $5 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider US-2 in conjunction with the Scott Solar, Whitehouse, and Woodland solar facilities. In April 2017, the Virginia Commission established a 9.4% ROE for Rider US-2 effective September 1, 2017. In June 2017, the Virginia Commission approved a $10 million revenue requirement, subject to true-up, for the rate year beginning September 1, 2017. In October 2017, Virginia Power proposed a $15 million revenue requirement for the rate year beginning September 1, 2018, which represents a $5 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider GV in conjunction with Greensville County. In February 2017, the Virginia Commission approved an $82 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 9.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved an $82 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 9.2% ROE effective April 1, 2018.

Electric Transmission Projects

In November 2013, the Virginia Commission issued an order granting Virginia Power a CPCN to construct approximately 7 miles of new overhead 500 kV transmission line from the existing Surry switching station in Surry County to a new Skiffes Creek switching station in James City County, and approximately 20 miles of new 230 kV transmission line in James City County, York County, and the City of Newport News from the proposed new Skiffes Creek switching station to Virginia Power's existing Whealton substation in the City of Hampton. As of July 2017, Virginia Power has received all major required permits and approvals and is proceeding with construction of the project. In connection with the receipt of the permit from the U.S. Army Corps of Engineers in July 2017, Virginia Power was required to make payments totaling approximately $90 million to fund improvements to historical and cultural resources near the project. Accordingly, in July 2017, Virginia Power recorded an increase to property, plant and equipment and a corresponding liability for these payment obligations. Through December 31, 2017, Virginia Power had made $90 million of such payments. Also in July 2017, the National Parks Conservation Association filed a lawsuit in U.S. District Court for the D.C. Circuit seeking to set aside the permit granted by the U.S. Army Corps of Engineers for the project and requested a preliminary injunction against the permit. In August 2017, the National Trust for Historic Preservation and Preservation Virginia filed a similar lawsuit in U.S. District Court for the D.C. Circuit. In October 2017, the preliminary injunction requests were denied. These lawsuits are pending.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to convert an existing transmission line to 230 kV in Prince William County, Virginia, and Loudoun County, Virginia, and to construct and operate a new approximately five mile overhead 230 kV double circuit transmission line between a tap point near the Gainesville substation and a new to-be-constructed Haymarket substation. The total estimated cost of the project is approximately $55 million. In April 2017, the Virginia Commission issued an interim order instructing Virginia Power to construct and operate the project along an approved route if Virginia Power could obtain all necessary rights-of-way. Otherwise, the Virginia Commission ruled that Virginia Power can construct and operate the project along an approved alternative route. In June 2017, the Virginia Commission issued a final order approving the alternative route for the project, and granted the necessary CPCN. In July 2017, the Virginia Commission retained jurisdiction over the case to evaluate two requests to reconsider its decisions. Also in July 2017, Virginia Power requested that the Virginia Commission stay the proceeding while Virginia Power discusses the proposed route with leaders of Prince William County. In December 2017, the Virginia Commission granted in part the two motions for reconsideration, retained jurisdiction for further proceedings in the case and stayed the effectiveness of its final order. This matter is pending.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate in multiple Virginia counties an approximately 38 mile overhead 230 kV transmission line between the Remington and Gordonsville substations, along with associated facilities. In August 2017, the Virginia Commission granted a CPCN for the project. The total estimated cost of the project is approximately $105 million.

In March 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in multiple Virginia counties approximately 33 miles of the existing 500 kV transmission line between the Cunningham switching station and the Dooms substation, along with associated station work. In May 2017, the Virginia Commission granted a CPCN to construct and operate the project. The total estimated cost of the project is approximately $60 million.

In August 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in multiple Virginia counties approximately 28 miles of the existing 500 kV transmission line between the Carson switching station and a terminus located near the Rogers Road switching station under construction in Greensville County, Virginia, along with associated work at the Carson switching station. In March 2017, the Virginia Commission granted a CPCN to construct and operate the project. The total estimated cost of the project is approximately $55 million.

In January 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and rearrange its Idylwood substation in Fairfax County, Virginia. In September 2017, the Virginia Commission granted a CPCN for the project. The total estimated cost of the project is approximately $110 million.

In June 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in Prince William County, Virginia, approximately 9 miles of existing 115 kV transmission lines between Possum Point Switching Station and NOVEC’s Smoketown delivery point, utilizing 230 kV design on the majority of the route, for total estimated cost of approximately $20 million. In February 2018, the Virginia Commission granted a CPCN for the project.

In September 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in Augusta County, Virginia approximately 18 miles of the existing 500 kV transmission line between the Dooms substation and the Valley substation, along with associated substation work, for a total estimated cost of approximately $65 million. This case is pending.

In November 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to build and operate in Fairfax County, Virginia approximately 4 miles of 230 kV transmission line between the Idylwood and Tysons substations, along with associated substation work. The total estimated cost of the project is approximately $125 million. This case is pending.

In February 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in Lancaster County, Virginia and Middlesex County, Virginia and across the Rappahannock River, approximately 2 miles of existing 115 kV transmission lines between Harmony Village Substation and White Stone Substation. In December 2017, the Virginia Commission granted a CPCN for the project to be constructed under the Rappahannock River. The total estimated cost of the project is approximately $85 million.

North Anna

Virginia Power is considering the construction of a third nuclear unit at a site located at North Anna nuclear power station. If Virginia Power decides to build a new unit, it would require a COL from the NRC, approval of the Virginia Commission and certain environmental permits and other approvals. In June 2017, the NRC issued the COL. Virginia Power has not yet committed to building a new nuclear unit at North Anna nuclear power station.

Requests by BREDL for a contested NRC hearing on Virginia Power’s COL application were dismissed, and in September 2016, the U.S. Court of Appeals for the D.C. Circuit dismissed with prejudice petitions for judicial review that BREDL and other organizations had filed challenging the NRC’s reliance on a rule generically assessing the environmental impacts of continued onsite storage of spent nuclear fuel in various licensing proceedings, including Virginia Power’s COL proceeding. This dismissal followed the Court’s June 2016 decision in New York v. NRC, upholding the NRC’s continued storage rule and August 2016 denial of requests for rehearing en banc. Therefore, the contested portion of the COL proceeding was closed. The NRC is required to conduct a hearing in all COL proceedings. This mandatory NRC hearing was held in March 2017, was uncontested and the resulting NRC decision authorized issuance of the COL.

In August 2016, Virginia Power received a 60-day notice of intent to sue from the Sierra Club alleging Endangered Species Act violations. The notice alleges that the U.S. Army Corps of Engineers failed to conduct adequate environmental and consultation reviews, related to a potential third nuclear unit located at North Anna, prior to issuing a CWA section 404 permit to Virginia Power in September 2011. No lawsuit was filed and in November 2016, the Army Corps of Engineers suspended the section 404 permit while it gathered additional information. The section 404 permit was reinstated in April 2017.

NORTH CAROLINA REGULATION

In August 2017, Virginia Power submitted its annual filing to the North Carolina Commission to adjust the fuel component of its

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electric rates. Virginia Power proposed a total $15 million increase to the fuel component of its electric rates for the rate year beginning January 1, 2018. In January 2018, the North Carolina Commission approved Virginia Power's proposed fuel charge adjustment.

OHIO REGULATION

PIR Program

In 2008, East Ohio began PIR, aimed at replacing approximately 25% of its pipeline system. In March 2015, East Ohio filed an application with the Ohio Commission requesting approval to extend the PIR program for an additional five years and to increase the annual capital investment, with corresponding increases in the annual rate-increase caps. In September 2016, the Ohio Commission approved a stipulation filed jointly by East Ohio and the Staff of the Ohio Commission to settle East Ohio's pending application. As requested, the PIR program and associated cost recovery will continue for another five-year term, calendar years 2017 through 2021, and East Ohio will be permitted to increase its annual capital expenditures to $200 million by 2018 and 3% per year thereafter subject to the cost recovery rate increase caps proposed by East Ohio.

In April 2017, the Ohio Commission approved East Ohio's application to adjust the PIR cost recovery rates for 2016 costs. The filing reflects gross plant investment for 2016 of $188 million, cumulative gross plant investment of $1.2 billion and a revenue requirement of $157 million.

AMR Program

In 2007, East Ohio began installing automated meter reading technology for its 1.2 million customers in Ohio. The AMR program approved by the Ohio Commission was completed in 2012. Although no further capital investment will be added, East Ohio is approved to recover depreciation, property taxes, carrying charges and a return until East Ohio has another rate case.

In April 2017, the Ohio Commission approved East Ohio's application to adjust its AMR cost recovery rate for 2016 costs. The filing reflects a revenue requirement of approximately $6 million.

PIPP Plus Program

Under the Ohio PIPP Plus Program, eligible customers can make reduced payments based on their ability to pay their bill. The difference between the customer's total bill and the PIPP amount is deferred and collected under the PIPP Rider in accordance with the rules of the Ohio Commission. In July 2017, East Ohio's annual update of the PIPP Rider was automatically approved by the Ohio Commission after a 45-day waiting period from the date of the filing. The revised rider rate reflects the recovery over the twelve-month period from July 2017 through June 2018 of projected deferred program costs of approximately $19 million from April 2017 through June 2018, net of a refund for over-recovery of accumulated arrearages of approximately $20 million as of March 31, 2017.

UEX Rider

East Ohio has approval for a UEX Rider through which it recovers the bad debt expense of most customers not participating in the PIPP Plus Program. The UEX Rider is adjusted annually to achieve dollar for dollar recovery of East Ohio's actual write-offs of uncollectible amounts. In September 2017, the Ohio Commission approved East Ohio's application requesting approval of its UEX Rider to reflect a refund of over-recovered accumulated bad debt expense of approximately $12 million as of March 31, 2017, and recovery of prospective net bad debt expense projected to total approximately $22 million for the twelve-month period from April 2017 to March 2018.

Ohio Legislation

In March 2017, the Governor of Ohio signed legislation into law that allows utilities to file an application to recover infrastructure development costs associated with economic development projects. The new cost recovery provision allows for projects totaling up to $22 million for East Ohio subject to Ohio Commission approval.

DSM Rider

East Ohio has approval for a DSM rider through which it recovers expenditures related to its DSM programs. In December 2017, East Ohio filed an application with the Ohio Commission seeking approval of an adjustment to the DSM rider to recover a total of $5 million, which includes an under-recovery of costs during the preceding 12-month period. This application is pending.

WEST VIRGINIA REGULATION

In October 2017, the West Virginia Commission approved Hope's application for new PREP customer rates, for the year beginning November 1, 2017, that provide for projected revenue of $4 million related to capital investments of $21 million, $27 million and $31 million for 2016, 2017 and 2018, respectively.

UTAH AND WYOMING REGULATION

In October 2017, Questar Gas submitted filings with both the Utah Commission and the Wyoming Commission for an approximately $25 million gas cost increase reflecting forecasted increases in commodity and transportation costs. The Utah Commission and the Wyoming Commission both approved the filings in October 2017 with rates effective November 2017.

FERC—GAS

Cove Point

In November 2016, pursuant to the terms of a previous settlement, Cove Point filed a general rate case for its FERC-jurisdictional services, with 23 proposed rates to be effective January 1, 2017. Cove Point proposed an annual cost-of-service of approximately $140 million. In December 2016, FERC accepted a January 1, 2017 effective date for all proposed rates but five which were suspended to be effective June 1, 2017. Under the terms of the settlement agreement filed by Cove Point in August 2017 and approved by FERC in November 2017, Cove Point's rates effective October 2017 result in decreases to annual revenues and depreciation expense of approximately $18 million and $3 million, respectively, compared to the rates in effect through December 2016.

DETI

In September 2017, DETI submitted its annual transportation cost rate adjustment to FERC requesting approval to recover $39 million. Also in September 2017, DETI submitted its annual electric power cost adjustment to FERC requesting approval to recover $6 million. In October 2017, FERC approved these adjustments.

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NOTE 14. ASSET RETIREMENT OBLIGATIONS

AROs represent obligations that result from laws, statutes, contracts and regulations related to the eventual retirement of certain of the Companies' long-lived assets. Dominion Energy's and Virginia Power's AROs are primarily associated with the decommissioning of their nuclear generation facilities and ash pond and landfill closures. Dominion Energy Gas' AROs primarily include plugging and abandonment of gas and oil wells and the interim retirement of natural gas gathering, transmission, distribution and storage pipeline components.

The Companies have also identified, but not recognized, AROs related to the retirement of Dominion Energy's LNG facility, Dominion Energy's and Dominion Energy Gas' storage wells in their underground natural gas storage network, certain Virginia Power electric transmission and distribution assets located on property with easements, rights of way, franchises and lease agreements, Virginia Power's hydroelectric generation facilities and the abatement of certain asbestos not expected to be disturbed in Dominion Energy's and Virginia Power's generation facilities. The Companies currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets since the economic lives of these assets can be extended indefinitely through regular repair and maintenance and they currently have no plans to retire or dispose of any of these assets. As a result, a settlement date is not determinable for these assets and AROs for these assets will not be reflected in the Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. The Companies continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets. The changes to AROs during 2016 and 2017 were as follows:

	Amount
(millions)	
Dominion Energy	
AROs at December 31, 2015	$2,103
Obligations incurred during the period(1)	204
Obligations settled during the period	(171)
Revisions in estimated cash flows(2)	245
Accretion	104
AROs at December 31, 2016(3)	$2,485
Obligations incurred during the period	**37**
Obligations settled during the period	**(214)**
Revisions in estimated cash flows	**7**
Accretion	**117**
AROs at December 31, 2017(3)	**$2,432**
Virginia Power	
AROs at December 31, 2015	$1,247
Obligations incurred during the period	9
Obligations settled during the period	(115)
Revisions in estimated cash flows(2)	245
Accretion	57
AROs at December 31, 2016	$1,443
Obligations incurred during the period	**11**
Obligations settled during the period	**(152)**
Revisions in estimated cash flows	**(1)**
Accretion	**64**
AROs at December 31, 2017	**$1,365**
Dominion Energy Gas	
AROs at December 31, 2015	$ 149
Obligations incurred during the period	6
Obligations settled during the period	(8)
Accretion	9
AROs at December 31, 2016(4)	$ 156
Obligations incurred during the period	**2**
Obligations settled during the period	**(7)**
Accretion	**9**
AROs at December 31, 2017(4)	**$ 160**

(1) Primarily reflects AROs assumed in the Dominion Energy Questar Combination. See Note 3 for further information.
(2) Primarily reflects future ash pond and landfill closure costs at certain utility generation facilities. See Note 22 for further information.
(3) Includes $249 million and $263 million reported in other current liabilities at December 31, 2016, and 2017, respectively.
(4) Includes $147 million and $146 million reported in other deferred credits and other liabilities, with the remainder recorded in other current liabilities, at December 31, 2016 and 2017, respectively.

Dominion Energy and Virginia Power have established trusts dedicated to funding the future decommissioning of their nuclear plants. At December 31, 2017 and 2016, the aggregate fair value of Dominion Energy's trusts, consisting primarily of equity and debt securities, totaled $5.1 billion and $4.5 billion, respectively. At December 31, 2017 and 2016, the aggregate fair value of Virginia Power's trusts, consisting primarily of debt and equity securities, totaled $2.4 billion and $2.1 billion, respectively.

NOTE 15. VARIABLE INTEREST ENTITIES

The primary beneficiary of a VIE is required to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that has both 1) the power to direct the activities that most significantly impact the entity's economic performance and 2) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

DOMINION ENERGY

At December 31, 2017, Dominion Energy owns the general partner, 50.6% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Energy Midstream, which owns a preferred equity interest and the general partner interest in Cove Point. Additionally, Dominion Energy owns the manager and 67% of the membership interest in certain merchant solar facilities, as discussed in Note 2. Dominion Energy has concluded that these entities are VIEs due to the limited partners or members lacking the characteristics of a controlling financial interest. In addition, in 2016 Dominion Energy created a wholly owned subsidiary, SBL Holdco, as a holding company of its interest in the VIE merchant solar facilities and accordingly SBL Holdco is a VIE. Dominion Energy is the primary beneficiary of Dominion Energy Midstream, SBL Holdco and the merchant solar facilities, and Dominion Energy Midstream is the primary beneficiary of Cove Point, as they have the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. Dominion Energy's securities due within one year and long-term debt include $30 million and $332 million, respectively, of debt issued in 2016 by SBL Holdco net of issuance costs that is nonrecourse to Dominion Energy and is secured by SBL Holdco's interest in the merchant solar facilities.

Dominion Energy owns a 48% membership interest in Atlantic Coast Pipeline. See Note 9 for more details regarding the nature of this entity. Dominion Energy concluded that Atlantic Coast Pipeline is a VIE because it has insufficient equity to finance its activities without additional subordinated financial support. Dominion Energy has concluded that it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance, as the power to direct

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is shared among multiple unrelated parties. Dominion Energy is obligated to provide capital contributions based on its ownership percentage. Dominion Energy's maximum exposure to loss is limited to its current and future investment as well as any obligations under a guarantee provided. See Note 22 for more information.

DOMINION ENERGY AND VIRGINIA POWER

Dominion Energy's and Virginia Power's nuclear decommissioning trust funds and Dominion Energy's rabbi trusts hold investments in limited partnerships or similar type entities (see Note 9 for further details). Dominion Energy and Virginia Power concluded that these partnership investments are VIEs due to the limited partners lacking the characteristics of a controlling financial interest. Dominion Energy and Virginia Power have concluded neither is the primary beneficiary as they do not have the power to direct the activities that most significantly impact these VIEs' economic performance. Dominion Energy and Virginia Power are obligated to provide capital contributions to the partnerships as required by each partnership agreement based on their ownership percentages. Dominion Energy and Virginia Power's maximum exposure to loss is limited to their current and future investments.

DOMINION ENERGY AND DOMINION ENERGY GAS

Dominion Energy previously concluded that Iroquois was a VIE because a non-affiliated Iroquois equity holder had the ability during a limited period of time to transfer its ownership interests to another Iroquois equity holder or its affiliate. At the end of the first quarter 2016, such right no longer existed and, as a result, Dominion Energy concluded that Iroquois is no longer a VIE.

VIRGINIA POWER

Virginia Power had long-term power and capacity contracts with five non-utility generators, which contain certain variable pricing mechanisms in the form of partial fuel reimbursement that Virginia Power considers to be variable interests. Contracts with two of these non-utility generators expired during 2015 and two additional contracts expired during 2017, leaving a remaining aggregate summer generation capacity of approximately 218 MW. After an evaluation of the information provided by these entities, Virginia Power was unable to determine whether they were VIEs. However, the information they provided, as well as Virginia Power's knowledge of generation facilities in Virginia, enabled Virginia Power to conclude that, if they were VIEs, it would not be the primary beneficiary. This conclusion reflects Virginia Power's determination that its variable interests do not convey the power to direct the most significant activities that impact the economic performance of the remaining entity during the remaining terms of Virginia Power's contract and for the years the entity is expected to operate after its contractual relationship expires. The remaining contract expires in 2021. Virginia Power is not subject to any risk of loss from this potential VIE other than its remaining purchase commitments which totaled $200 million as of December 31, 2017. Virginia Power paid $86 million, $144 million, and $200 million for electric capacity and $24 million, $31 million, and $83 million for electric energy to these entities for the years ended December 31, 2017, 2016 and 2015, respectively.

DOMINION ENERGY GAS

DETI has been engaged to oversee the construction of, and to subsequently operate and maintain, the projects undertaken by Atlantic Coast Pipeline based on the overall direction and oversight of Atlantic Coast Pipeline's members. An affiliate of DETI holds a membership interest in Atlantic Coast Pipeline, therefore DETI is considered to have a variable interest in Atlantic Coast Pipeline. The members of Atlantic Coast Pipeline hold the power to direct the construction, operations and maintenance activities of the entity. DETI has concluded it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance. DETI has no obligation to absorb any losses of the VIE. See Note 24 for information about associated related party receivable balances.

VIRGINIA POWER AND DOMINION ENERGY GAS

Virginia Power and Dominion Energy Gas purchased shared services from DES, an affiliated VIE, of $340 million and $126 million, $346 million and $123 million, and $318 million and $115 million for the years ended December 31, 2017, 2016 and 2015, respectively. Virginia Power and Dominion Energy Gas determined that neither is the primary beneficiary of DES as neither has both the power to direct the activities that most significantly impact its economic performance as well as the obligation to absorb losses and benefits which could be significant to it. DES provides accounting, legal, finance and certain administrative and technical services to all Dominion Energy subsidiaries, including Virginia Power and Dominion Energy Gas. Virginia Power and Dominion Energy Gas have no obligation to absorb more than their allocated shares of DES costs.

NOTE 16. SHORT-TERM DEBT AND CREDIT AGREEMENTS

The Companies use short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, Dominion Energy utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion Energy's credit ratings and the credit quality of its counterparties.

DOMINION ENERGY

Commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

	Facility Limit	Outstanding Commercial Paper(2)	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
At December 31, 2017				
Joint revolving credit facility(1)	**$5,000**	**$3,298**	**$ —**	**$1,702**
Joint revolving credit facility(1)	**500**	**—**	**76**	**424**
Total	**$5,500**	**$3,298**	**$76**	**$2,126**
At December 31, 2016				
Joint revolving credit facility(1)	$5,000	$3,155	$ —	$1,845
Joint revolving credit facility(1)	500	—	85	415
Total	$5,500	$3,155	$85	$2,260

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(1) These credit facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to a combined $2.0 billion of letters of credit.
(2) The weighted-average interest rates of the outstanding commercial paper supported by Dominion Energy's credit facilities were 1.61% and 1.05% at December 31, 2017 and 2016, respectively.

Questar Gas' short-term financing is supported through its access as co-borrower to the two joint revolving credit facilities discussed above with Dominion Energy, Virginia Power and Dominion Energy Gas. At December 31, 2017, the aggregate sub-limit for Questar Gas was $250 million. In December 2016, Questar Gas entered into a commercial paper program pursuant to which it began accessing the commercial paper markets.

Dominion Energy has indicated its intention to replace the existing two joint revolving credit facilities with a $6.0 billion joint revolving credit facility in the first quarter of 2018. Terms and covenants of the new credit facility are expected to be similar to the existing credit facilities, including that Virginia Power, Dominion Energy Gas and Questar Gas will remain as co-borrowers, except that the maturity will be in five years and the maximum allowed total debt to total capital ratio, with respect to Dominion Energy only, will be increased from 65% to 67.5%. In February 2018, Virginia Power, as co-borrower, filed with the Virginia Commission for approval.

In addition to the credit facilities mentioned above, SBL Holdco has $30 million of credit facilities which have an original stated maturity date of December 2017 with automatic one-year renewals through the maturity of the SBL Holdco term loan agreement in 2023. Dominion Solar Projects III, Inc. has $25 million of credit facilities which have an original stated maturity date of May 2018 with automatic one-year renewals through the maturity of the Dominion Solar Projects III, Inc. term loan agreement in 2024. At December 31, 2017, no amounts were outstanding under either of these facilities.

In February 2018, Dominion Energy borrowed $950 million under a 364-Day Term Loan Agreement that bears interest at a variable rate. In addition, the agreement contains a maximum allowed total debt to total capital ratio of 67.5%.

VIRGINIA POWER

Virginia Power's short-term financing is supported through its access as co-borrower to the two joint revolving credit facilities. These credit facilities can be used for working capital, as support for the combined commercial paper programs of the Companies and for other general corporate purposes.

Virginia Power's share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion Energy, Dominion Energy Gas and Questar Gas were as follows:

	Facility Limit(1)	Outstanding Commercial Paper(2)	Outstanding Letters of Credit
(millions)			
At December 31, 2017			
Joint revolving credit facility(1)	**$5,000**	**$542**	**$—**
Joint revolving credit facility(1)	**500**	**—**	**—**
Total	**$5,500**	**$542**	**$—**
At December 31, 2016			
Joint revolving credit facility(1)	$5,000	$ 65	$—
Joint revolving credit facility(1)	500	—	1
Total	$5,500	$ 65	$ 1

(1) The full amount of the facilities is available to Virginia Power, less any amounts outstanding to co-borrowers Dominion Energy, Dominion Energy Gas and Questar Gas. Sub-limits for Virginia Power are set within the facility limit but can be changed at the option of the Companies multiple times per year. At December 31, 2017, the sub-limit for Virginia Power was an aggregate $1.5 billion. If Virginia Power has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion Energy. These facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $2.0 billion (or the sub-limit, whichever is less) of letters of credit.
(2) The weighted-average interest rates of the outstanding commercial paper supported by these credit facilities were 1.65% and 0.97% at December 31, 2017 and 2016, respectively.

In addition to the credit facility commitments mentioned above, Virginia Power also has a $100 million credit facility with a maturity date of April 2020. As of December 31, 2017, this facility supports $100 million of certain variable rate tax-exempt financings of Virginia Power. In February 2018, Virginia Power provided notice to redeem all $100 million of outstanding variable rate tax-exempt financings supported by this credit facility.

DOMINION ENERGY GAS

Dominion Energy Gas' short-term financing is supported by its access as co-borrower to the two joint revolving credit facilities. These credit facilities can be used for working capital, as support for the combined commercial paper programs of the Companies and for other general corporate purposes.

Dominion Energy Gas' share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion Energy, Virginia Power and Questar Gas were as follows:

	Facility Limit(1)	Outstanding Commercial Paper(2)	Outstanding Letters of Credit
(millions)			
At December 31, 2017			
Joint revolving credit facility(1)	**$1,000**	**$629**	**$—**
Joint revolving credit facility(1)	**500**	**—**	**—**
Total	**$1,500**	**$629**	**$—**
At December 31, 2016			
Joint revolving credit facility(1)	$1,000	$460	$—
Joint revolving credit facility(1)	500	—	—
Total	$1,500	$460	$—

(1) A maximum of a combined $1.5 billion of the facilities is available to Dominion Energy Gas, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion Energy, Virginia Power and Questar Gas. Sub-limits for Dominion Energy Gas are set within the facility limit but can be changed at the option of the Companies multiple times per year. At December 31, 2017, the sub-limit for Dominion Energy Gas was an aggregate $750 million. If Dominion Energy Gas has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion Energy. These credit facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion (or the sub-limit, whichever is less) of letters of credit.
(2) The weighted-average interest rate of the outstanding commercial paper supported by these credit facilities was 1.57% and 1.00% at December 31, 2017 and 2016, respectively.

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NOTE 17. LONG-TERM DEBT

At December 31, (millions, except percentages)	2017 Weighted-average Coupon(1)	2017	2016
Dominion Energy Gas Holdings, LLC:			
Unsecured Senior Notes:			
2.5% and 2.8%, due 2019 and 2020	**2.68%**	**$ 1,150**	$ 1,150
2.875% to 4.8%, due 2023 to 2044(2)	**3.90%**	**2,450**	2,413
Dominion Energy Gas Holdings, LLC total principal		**$ 3,600**	$ 3,563
Unamortized discount and debt issuance costs		**(30)**	(35)
Dominion Energy Gas Holdings, LLC total long-term debt		**$ 3,570**	$ 3,528
Virginia Electric and Power Company:			
Unsecured Senior Notes:			
1.2% to 7.25%, due 2017 to 2022	**3.92%**	**$ 1,950**	$ 2,554
2.75% to 8.875%, due 2023 to 2047	**4.53%**	**8,690**	7,190
Tax-Exempt Financings(3):			
Variable rates, due 2017 to 2027	**1.27%**	**100**	175
1.75% to 5.6%, due 2023 to 2041	**2.25%**	**678**	678
Virginia Electric and Power Company total principal		**$11,418**	$10,597
Securities due within one year	**4.17%**	**(850)**	(678)
Unamortized discount, premium and debt issuances costs, net		**(72)**	(67)
Virginia Electric and Power Company total long-term debt		**$10,496**	$ 9,852
Dominion Energy, Inc.:			
Unsecured Senior Notes:			
Variable rates, due 2019 and 2020	**1.99%**	**$ 800**	$ —
1.25% to 6.4%, due 2017 to 2022	**2.95%**	**5,800**	5,750
2.85% to 7.0%, due 2024 to 2044	**4.72%**	**5,049**	4,649
Tax-Exempt Financing, variable rate, due 2041(4)		**—**	75
Unsecured Junior Subordinated Notes:			
2.579% to 4.104%, due 2019 to 2021	**3.08%**	**2,100**	1,100
Payable to Affiliated Trust, 8.4% due 2031	**8.40%**	**10**	10
Enhanced Junior Subordinated Notes:			
5.25% and 5.75%, due 2054 and 2076	**5.48%**	**1,485**	1,485
Variable rates, due 2066	**4.15%**	**422**	422
Remarketable Subordinated Notes, 1.5% and 2.0%, due 2020 to 2024	**2.00%**	**1,400**	2,400
Unsecured Debentures and Senior Notes(5):			
6.8% and 6.875%, due 2026 and 2027	**6.81%**	**89**	89
Term Loan, variable rate, due 2017(6)		**—**	250
Unsecured Senior and Medium-Term Notes(6):			
5.31% to 6.85%, due 2017 and 2018	**5.72%**	**120**	135
2.98% to 7.20%, due 2024 to 2051	**4.37%**	**600**	500
Term Loans, variable rates, due 2023 and 2024(7)	**3.74%**	**638**	405
Tax-Exempt Financing, 1.55%, due 2033(8)	**1.55%**	**27**	27
Dominion Energy Midstream Partners, LP:			
Term Loan, variable rate, due 2019	**2.74%**	**300**	300
Unsecured Senior and Medium-Term Notes, 5.83% and 6.48%, due 2018(9)	**5.84%**	**255**	255
Unsecured Senior Notes, 4.875%, due 2041(9)	**4.88%**	**180**	180
Dominion Energy Gas Holdings, LLC total principal (from above)		**3,600**	3,563
Virginia Electric and Power Company total principal (from above)		**11,418**	10,597
Dominion Energy, Inc. total principal		**$34,293**	$32,192
Fair value hedge valuation(10)		**(22)**	(1)
Securities due within one year(11) (12)	**3.44%**	**(3,078)**	(1,709)
Unamortized discount, premium and debt issuance costs, net		**(245)**	(251)
Dominion Energy, Inc. total long-term debt		**$30,948**	$30,231

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2017.
(2) Amount includes foreign currency remeasurement adjustments.
(3) These financings relate to certain pollution control equipment at Virginia Power's generating facilities. As of December 31, 2017, certain variable rate tax-exempt financings are supported by a $100 million credit facility that terminates in April 2020. In February 2018, Virginia Power provided notice to redeem three series of variable rate tax-exempt financings with an aggregate outstanding principal of $100 million. The financings would otherwise mature in 2024, 2026 and 2027.
(4) Represents variable rate Massachusetts Development Finance Agency Solid Waste Disposal Revenue Bonds due in 2041 repaid in August 2017.

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Combined Notes to Consolidated Financial Statements, Continued

(5) Represents debt assumed by Dominion Energy from the merger of its former CNG subsidiary.
(6) Represents debt obligations of Dominion Energy Questar or Questar Gas. See Note 3 for more information.
(7) Represents debt associated with SBL Holdco and Dominion Solar Projects III, Inc. The debt is nonrecourse to Dominion Energy and is secured by SBL Holdco's and Dominion Solar Projects III, Inc.'s interest in certain merchant solar facilities.
(8) Represents debt obligations of a DGI subsidiary.
(9) Represents debt obligations of Dominion Energy Questar Pipeline. See Note 3 for more information.
(10) Represents the valuation of certain fair value hedges associated with Dominion Energy's fixed rate debt.
(11) Excludes $250 million of Dominion Energy Questar Pipeline's senior notes that matured in February 2018 which were repaid using proceeds from the January 2018 issuance, through private placement, of $100 million of 3.53% senior notes and $150 million of 3.91% senior notes that mature in 2028 and 2038, respectively.
(12) Includes $20 million of estimated mandatory prepayments due within one year based on estimated cash flows in excess of debt service at SBL Holdco and Dominion Solar Projects III, Inc.

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2017, were as follows:

(millions, except percentages)	2018	2019	2020	2021	2022	Thereafter	Total
Dominion Energy Gas	$ —	$ 450	$ 700	$ —	$ —	$ 2,450	$ 3,600
Weighted-average Coupon		2.50%	2.80%			3.90%	
Virginia Power							
Unsecured Senior Notes	$ 850	$ 350	$ —	$ —	$ 750	$ 8,690	$10,640
Tax-Exempt Financings	—	—	—	—	—	778	778
Total	$ 850	$ 350	$ —	$ —	$ 750	$ 9,468	$11,418
Weighted-average Coupon	4.17%	5.00%			3.15%	4.33%	
Dominion Energy							
Term Loans(1)	$ 36	$ 336	$ 35	$ 35	$ 34	$ 462	$ 938
Unsecured Senior Notes(2)	3,275	3,400	1,000	900	1,500	17,058	27,133
Tax-Exempt Financings	—	—	—	—	—	805	805
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts	—	—	—	—	—	10	10
Unsecured Junior Subordinated Notes	—	550	1,000	550	—	—	2,100
Enhanced Junior Subordinated Notes	—	—	—	—	—	1,907	1,907
Remarketable Subordinated Notes	—	—	—	700	—	700	1,400
Total	$3,311	$4,286	$2,035	$2,185	$1,534	$20,942	$34,293
Weighted-average Coupon	3.62%	2.89%	2.58%	3.12%	2.97%	4.38%	

(1) Excludes mandatory prepayments associated with SBL Holdco and Dominion Solar Projects III, Inc. based on cash flows in excess of debt service. At December 31, 2017, $20 million of estimated mandatory prepayments due within one year were included in securities due within one year in Dominion Energy's Consolidated Balance Sheets.
(2) In February 2018, $250 million of Dominion Energy Questar Pipeline's senior notes were repaid using proceeds from the January 2018 issuance, through private placements, of $100 million of 3.53% senior notes and $150 million of 3.91% senior notes that mature in 2028 and 2038, respectively. As a result, at December 31, 2017, $250 million was included in long-term debt in the Consolidated Balance Sheets.

The Companies short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2017, there were no events of default under these covenants.

Enhanced Junior Subordinated Notes

In June 2006 and September 2006, Dominion Energy issued $300 million of June 2006 hybrids and $500 million of September 2006 hybrids, respectively. Beginning June 30, 2016, the June 2006 hybrids bear interest at three-month LIBOR plus 2.825%, reset quarterly. Previously, interest was fixed at 7.5% per year. The September 2006 hybrids bear interest at the three-month LIBOR plus 2.3%, reset quarterly.

In October 2014, Dominion Energy issued $685 million of October 2014 hybrids that will bear interest at 5.75% per year until October 1, 2024. Thereafter, they will bear interest at the three-month LIBOR plus 3.057%, reset quarterly.

Dominion Energy may defer interest payments on the hybrids on one or more occasions for up to 10 consecutive years. If the interest payments on the hybrids are deferred, Dominion Energy may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments during the deferral period. Also, during the deferral period, Dominion Energy may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the hybrids.

Dominion Energy executed RCCs in connection with its issuance of the June 2006 hybrids and the September 2006 hybrids. Under the terms of the RCCs, Dominion Energy covenants to and for the benefit of designated covered debtholders, as may be designated from time to time, that Dominion Energy shall not redeem, repurchase, or defease all or any part of the hybrids, and shall not cause its majority owned subsidiaries to purchase all or any part of the hybrids, on or before their applicable RCC termination date, unless, subject to certain limitations, during the 180 days prior to such activity, Dominion Energy has received a specified amount of proceeds as set forth in the RCCs from the sale of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than the applicable characteristics of the hybrids at that time, as more fully described in the RCCs. In September 2011, Dominion Energy amended the RCCs of the June 2006 hybrids and September 2006 hybrids to expand the measurement period for consideration of proceeds from the sale of common stock issuances from 180 days to 365 days. The proceeds Dominion Energy receives from the replacement offering, adjusted by a predetermined factor, must equal or exceed the redemption or repurchase price.

In 2015, Dominion Energy purchased and cancelled $14 million and $3 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In the first quarter of 2016, Dominion Energy purchased and cancelled $38 million and $4 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In July 2016, Dominion Energy launched a tender offer to purchase up to $200 million in aggregate of additional June 2006 hybrids and September 2006 hybrids, which expired on August 1, 2016. In connection with the tender offer, Dominion Energy purchased and cancelled $125 million and $74 million of the June 2006 hybrids and the September 2006 hybrids, respectively. All purchases were conducted in compliance with the applicable RCC. Also in July 2016, Dominion Energy issued $800 million of 5.25% July 2016 hybrids. The proceeds were used for general corporate purposes, including to finance the tender offer. The July 2016 hybrids are listed on the NYSE under the symbol DRUA.

Remarketable Subordinated Notes

In June 2013, Dominion Energy issued $550 million of 2013 Series A 6.125% Equity Units and $550 million of 2013 Series B 6.0% Equity Units, initially in the form of Corporate Units. In July 2014, Dominion Energy issued $1.0 billion of 2014 Series A 6.375% Equity Units, initially in the form of Corporate Units. The Corporate Units were listed on the NYSE under the symbols DCUA, DCUB and DCUC respectively.

Each Corporate Unit consisted of a stock purchase contract and 1/20 interest in a RSN issued by Dominion Energy. The stock purchase contracts obligated the holders to purchase shares of Dominion Energy common stock at a future settlement date prior to the relevant RSN maturity date. The purchase price paid under the stock purchase contracts was $50 per Corporate Unit and the number of shares purchased was determined under a formula based upon the average closing price of Dominion Energy common stock near the settlement date. The RSNs were pledged as collateral to secure the purchase of common stock under the related stock purchase contracts.

In May 2017, Dominion Energy successfully remarketed the $1.0 billion 2014 Series A 1.50% RSNs due 2020 pursuant to the terms of the related 2014 Equity Units. In connection with the remarketing, the interest rate on the junior subordinated notes was reset to 2.579%, payable on a semi-annual basis and Dominion Energy ceased to have the ability to redeem the notes at its option or defer interest payments. In March 2016 and May 2016, Dominion Energy successfully remarketed the $550 million 2013 Series A 1.07% RSNs due 2021 and the $550 million 2013 Series B 1.18% RSNs due 2019, respectively, pursuant to the terms of the related 2013 Equity Units. In connection with the remarketings, the interest rate on the Series A and Series B junior subordinated notes was reset to 4.104% and 2.962%, respectively, payable on a semi-annual basis and Dominion Energy ceased to have the ability to redeem the notes at its option or defer interest payments. At December 31, 2017, the securities are included in junior subordinated notes in Dominion Energy's Consolidated Balance Sheets. Dominion Energy did not receive any proceeds from the remarketings. Remarketing proceeds belonged to the investors holding the related equity units and were temporarily used to purchase a portfolio of treasury securities. Upon maturity of each portfolio, the proceeds were applied on behalf of investors on the related stock purchase contract settlement date to pay the purchase price to Dominion Energy for issuance of 12.5 million shares of its common stock in July 2017 and 8.5 million shares of its common stock in both April 2016 and July 2016. See Issuance of Common Stock below for a description of common stock issued by Dominion Energy under the stock purchase contracts.

In August 2016, Dominion Energy issued $1.4 billion of 2016 Series A 6.75% Equity Units, initially in the form of Corporate Units. The Corporate Units are listed on the NYSE under the symbol DCUD. The net proceeds from the 2016 Equity Units were used to finance the Dominion Energy Questar Combination. See Note 3 for more information.

Each 2016 Series A Corporate Unit consists of a stock purchase contract, a 1/40 interest in a 2016 Series A-1 RSN issued by Dominion Energy and a 1/40 interest in a 2016 Series A-2 RSN issued by Dominion Energy. The stock purchase contracts obligate the holders to purchase shares of Dominion Energy common stock at a future settlement date prior to the relevant RSN maturity date. The purchase price to be paid under the stock purchase contracts is $50 per Corporate Unit and the number of shares to be purchased will be determined under a formula based upon the average closing price of Dominion Energy common stock near the settlement date. The RSNs are pledged as collateral to secure the purchase of common stock under the related stock purchase contracts.

Dominion Energy makes quarterly interest payments on the RSNs and quarterly contract adjustment payments on the stock purchase contracts, at the rates described below. Dominion Energy may defer payments on the stock purchase contracts and the RSNs for one or more consecutive periods but generally not beyond the purchase contract settlement date. If payments are deferred, Dominion Energy may not make any cash distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, Dominion Energy may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the RSNs.

Dominion Energy has recorded the present value of the stock purchase contract payments as a liability offset by a charge to equity. Interest payments on the RSNs are recorded as interest expense and stock purchase contract payments are charged against the liability. Accretion of the stock purchase contract liability is recorded as imputed interest expense. In calculating diluted EPS, Dominion Energy applies the treasury stock method to the equity units.

Pursuant to the terms of the 2016 Equity Units, Dominion Energy expects to remarket both the 2016 Series A-1 and 2016 Series A-2 RSNs during the third quarter of 2019. Following a successful remarketing, the interest rate on the RSNs will be reset, interest will be payable on a semi-annual basis and Dominion Energy will cease to have the ability to redeem the RSNs at its option or defer interest payments. Proceeds of each remarketing will belong to the investors in the related equity units and will be held and applied on their behalf at the settlement date of the related stock purchase contracts to pay the purchase price to Dominion Energy for issuance of its common stock.

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Combined Notes to Consolidated Financial Statements, Continued

Under the terms of the stock purchase contracts, assuming no anti-dilution or other adjustments, Dominion Energy will issue between 15.0 million and 18.8 million shares in August 2019. A total of 23.1 million shares of Dominion Energy's common stock has been reserved for issuance in connection with the stock purchase contracts.

Selected information about Dominion Energy's equity units is presented below:

Issuance Date	Units Issued	Total Net Proceeds	Total Long-term Debt	RSN Annual Interest Rate	Stock Purchase Contract Annual Rate	Stock Purchase Contract Liability(1)	Stock Purchase Settlement Date
(millions, except interest rates)							
8/15/2016(2)	28	$1,374.8	$1,400.0	2.000%(3)	4.750%	$190.6	8/15/2019

(1) Payments of $101 million and $94 million were made in 2017 and 2016, respectively, including payments for the remarketed 2013 Series A and B notes and the remarketed 2014 Series A notes. The stock purchase contract liability was $111 million and $212 million at December 31, 2017 and 2016, respectively.

(2) The maturity dates of the $700 million Series A-1 RSNs and $700 million Series A-2 RSNs are August 15, 2021 and August 15, 2024, respectively.

(3) Annual interest rate applies to each of the Series A-1 RSNs and Series A-2 RSNs.

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NOTE 18. PREFERRED STOCK

Dominion Energy is authorized to issue up to 20 million shares of preferred stock; however, none were issued and outstanding at December 31, 2017 or 2016.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference; however, none were issued and outstanding at December 31, 2017 or 2016.

NOTE 19. EQUITY

Issuance of Common Stock

DOMINION ENERGY

Dominion Energy maintains Dominion Energy Direct® and a number of employee savings plans through which contributions may be invested in Dominion Energy's common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans. In January 2014, Dominion Energy began purchasing its common stock on the open market for these plans. In April 2014, Dominion Energy began issuing new common shares for these direct stock purchase plans.

During 2017, Dominion Energy received cash proceeds, net of fees and commissions, of $1.3 billion from the issuance of approximately 17 million shares of common stock through various programs resulting in approximately 645 million shares of common stock outstanding at December 31, 2017. These proceeds include cash of $302 million received from the issuance of 3.8 million of such shares through Dominion Energy Direct® and employee savings plans.

In July 2017, Dominion Energy issued 12.5 million shares under the related stock purchase contracts entered into as part of Dominion Energy's 2014 Equity Units and received proceeds of $1.0 billion.

In both April 2016 and July 2016, Dominion Energy issued 8.5 million shares under the related stock purchase contracts entered into as part of Dominion Energy's 2013 Equity Units and received $1.1 billion of total proceeds. Additionally, Dominion Energy completed a market issuance of equity in April 2016 of 10.2 million shares and received proceeds of $756 million through a registered underwritten public offering. A portion of the net proceeds was used to finance the Dominion Energy Questar Combination. See Note 3 for more information.

In June 2017, Dominion Energy filed an SEC shelf registration for the sale of debt and equity securities including the ability to sell common stock through an at-the-market program. Also in June 2017, Dominion Energy entered into three separate sales agency agreements to effect sales under the program and pursuant to which it may offer from time to time up to $500 million aggregate amount of its common stock. Sales of common stock can be made by means of privately negotiated transactions, as transactions on the NYSE at market prices or in such other transactions as are agreed upon by Dominion Energy and the sales agents in conformance with applicable securities laws. In January 2018, Dominion Energy provided sales instructions to one of the sales agents and has issued 6.6 million shares through at-the-market issuances and received cash proceeds of $495 million, net of fees and commissions paid of $5 million. Following these issuances, Dominion Energy has no remaining ability to issue stock under the 2017 sales agency agreements and has completed the program.

VIRGINIA POWER

In 2017, 2016 and 2015, Virginia Power did not issue any shares of its common stock to Dominion Energy.

Shares Reserved for Issuance

At December 31, 2017, Dominion Energy had approximately 67 million shares reserved and available for issuance for Dominion Energy Direct®, employee stock awards, employee savings plans, director stock compensation plans and issuance in connection with stock purchase contracts. See Note 17 for more information.

Repurchase of Common Stock

Dominion Energy did not repurchase any shares in 2017 or 2016 and does not plan to repurchase shares during 2018, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which do not count against its stock repurchase authorization.

Purchase of Dominion Energy Midstream Units

In September 2015, Dominion Energy initiated a program to purchase from the market up to $50 million of common units representing limited partner interests in Dominion Energy Midstream, which expired in September 2016. Dominion Energy purchased approximately 658,000 common units for $17 million and 887,000 common units for $25 million for the years ended December 31, 2016 and 2015, respectively.

Issuance of Dominion Energy Midstream Units

In 2017, Dominion Energy Midstream received $18 million of proceeds from the issuance of common units through its at-the-market program.

In 2016, Dominion Energy Midstream received $482 million of proceeds from the issuance of common units and $490 million of proceeds from the issuance of convertible preferred units. The net proceeds were primarily used to finance a portion of the acquisition of Dominion Energy Questar Pipeline from Dominion Energy. See Note 3 for more information.

The holders of the convertible preferred units are entitled to receive cumulative quarterly distributions payable in cash or additional convertible preferred units, subject to certain conditions. The units are convertible into Dominion Energy Midstream common units on a one-for-one basis, subject to certain adjustments, (i) in whole or in part at the option of the unitholders any time after December 1, 2018 or, (ii) in whole or in part at Dominion Energy Midstream's option, subject to certain conditions, any time after December 1, 2019. The conversion of such units would result in a potential increase to Dominion Energy's net income attributable to noncontrolling interests.

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Combined Notes to Consolidated Financial Statements, Continued

Accumulated Other Comprehensive Income (Loss)

Presented in the table below is a summary of AOCI by component:

At December 31,	2017	2016
(millions)		
Dominion Energy		
Net deferred losses on derivatives-hedging activities, net of tax of $188 and $173	**$ (301)**	$ (280)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(419) and $(318)	**747**	569
Net unrecognized pension and other postretirement benefit costs, net of tax of $692 and $691	**(1,101)**	(1,082)
Other comprehensive loss from equity method investees, net of tax of $2 and $4	**(3)**	(6)
Total AOCI, including noncontrolling interest	**$ (658)**	$ (799)
Less other comprehensive income attributable to noncontrolling interest	**1**	—
Total AOCI, excluding noncontrolling interest	**$ (659)**	$ (799)
Virginia Power		
Net deferred losses on derivatives-hedging activities, net of tax of $8 and $5	**$ (12)**	$ (8)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(47) and $(35)	**74**	54
Total AOCI	**$ 62**	$ 46
Dominion Energy Gas		
Net deferred losses on derivatives-hedging activities, net of tax of $15 and $15	**$ (23)**	$ (24)
Net unrecognized pension costs, net of tax of $59 and $68	**(75)**	(99)
Total AOCI	**$ (98)**	$ (123)

DOMINION ENERGY

The following table presents Dominion Energy's changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Unrecognized pension and other postretirement benefit costs	Other comprehensive loss from equity method investees	Total
(millions)					
Year Ended December 31, 2017					
Beginning balance	**$(280)**	**$569**	**$(1,082)**	**$(6)**	**$(799)**
Other comprehensive income before reclassifications: gains (losses)	**8**	**215**	**(69)**	**3**	**157**
Amounts reclassified from AOCI: (gains) losses(1)	**(29)**	**(37)**	**50**	**—**	**(16)**
Net current period other comprehensive income (loss)	**(21)**	**178**	**(19)**	**3**	**141**
Less other comprehensive income attributable to noncontrolling interest	**1**	**—**	**—**	**—**	**1**
Ending balance	**$(302)**	**$747**	**$(1,101)**	**$(3)**	**$(659)**
Year Ended December 31, 2016					
Beginning balance	$(176)	$504	$ (797)	$(5)	$(474)
Other comprehensive income before reclassifications: gains (losses)	55	93	(319)	(1)	(172)
Amounts reclassified from AOCI: (gains) losses(1)	(159)	(28)	34	—	(153)
Net current period other comprehensive income (loss)	(104)	65	(285)	(1)	(325)
Ending balance	$(280)	$569	$(1,082)	$(6)	$(799)

(1) See table below for details about these reclassifications.

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The following table presents Dominion Energy's reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2017		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	**$ (81)**	Operating revenue
	2	Purchased gas
Interest rate contracts	**52**	Interest and related charges
Foreign currency contracts	**(20)**	Other Income
Total	**(47)**	
Tax	**18**	Income tax expense
Total, net of tax	**$ (29)**	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	**$ (81)**	Other income
Impairment	**23**	Other income
Total	**(58)**	
Tax	**21**	Income tax expense
Total, net of tax	**$ (37)**	
Unrecognized pension and other postretirement benefit costs:		
Amortization of prior-service costs (credits)	**$ (21)**	Other operations and maintenance
Amortization of actuarial losses	**103**	Other operations and maintenance
Total	**82**	
Tax	**(32)**	Income tax expense
Total, net of tax	**$ 50**	
Year Ended December 31, 2016		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$(330)	Operating revenue
	13	Purchased gas
	10	Electric fuel and other energy-related purchases
Interest rate contracts	31	Interest and related charges
Foreign currency contracts	17	Other Income
Total	(259)	
Tax	100	Income tax expense
Total, net of tax	$(159)	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$ (66)	Other income
Impairment	23	Other income
Total	(43)	
Tax	15	Income tax expense
Total, net of tax	$ (28)	
Unrecognized pension and other postretirement benefit costs:		
Prior-service costs (credits)	$ (15)	Other operations and maintenance
Actuarial losses	71	Other operations and maintenance
Total	56	
Tax	(22)	Income tax expense
Total, net of tax	$ 34	

VIRGINIA POWER

The following table presents Virginia Power's changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Total
(millions)			
Year Ended December 31, 2017			
Beginning balance	**$ (8)**	**$54**	**$46**
Other comprehensive income before reclassifications: gains (losses)	**(5)**	**24**	**19**
Amounts reclassified from AOCI: (gains) losses(1)	**1**	**(4)**	**(3)**
Net current period other comprehensive income (loss)	**(4)**	**20**	**16**
Ending balance	**$(12)**	**$74**	**$62**
Year Ended December 31, 2016			
Beginning balance	$ (7)	$47	$40
Other comprehensive income before reclassifications: gains (losses)	(2)	11	9
Amounts reclassified from AOCI: (gains) losses(1)	1	(4)	(3)
Net current period other comprehensive income (loss)	(1)	7	6
Ending balance	$ (8)	$54	$46

(1) See table below for details about these reclassifications.

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Combined Notes to Consolidated Financial Statements, Continued

The following table presents Virginia Power's reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2017		
(Gains) losses on cash flow hedges:		
Interest rate contracts	**$ 1**	Interest and related charges
Total	**1**	
Tax	**—**	Income tax expense
Total, net of tax	**$ 1**	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	**$(9)**	Other income
Impairment	**2**	Other income
Total	**(7)**	
Tax	**3**	Income tax expense
Total, net of tax	**$(4)**	
Year Ended December 31, 2016		
(Gains) losses on cash flow hedges:		
Interest rate contracts	$ 1	Interest and related charges
Total	1	
Tax	—	Income tax expense
Total, net of tax	$ 1	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$(9)	Other income
Impairment	3	Other income
Total	(6)	
Tax	2	Income tax expense
Total, net of tax	$(4)	

DOMINION ENERGY GAS

The following table presents Dominion Energy Gas' changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrecognized pension costs	Total
(millions)			
Year Ended December 31, 2017			
Beginning balance	**$(24)**	**$(99)**	**$(123)**
Other comprehensive income before reclassifications: losses	**5**	**20**	**25**
Amounts reclassified from AOCI(1): losses	**(4)**	**4**	**—**
Net current period other comprehensive loss	**1**	**24**	**25**
Ending balance	**$(23)**	**$(75)**	**$ (98)**
Year Ended December 31, 2016			
Beginning balance	$(17)	$(82)	$ (99)
Other comprehensive income before reclassifications: (losses)	(16)	(20)	(36)
Amounts reclassified from AOCI(1): losses	9	3	12
Net current period other comprehensive income (loss)	(7)	(17)	(24)
Ending balance	$(24)	$(99)	$(123)

(1) See table below for details about these reclassifications.

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The following table presents Dominion Energy Gas' reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2017		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	**$ 8**	Operating revenue
Interest rate contracts	**5**	Interest and related charges
Foreign currency contracts	**(20)**	Other income
Total	**(7)**	
Tax	**3**	Income tax expense
Total, net of tax	**$ (4)**	
Unrecognized pension costs:		
Actuarial losses	**$ 6**	Other operations and maintenance
Total	**6**	
Tax	**(2)**	Income tax expense
Total, net of tax	**$ 4**	
Year Ended December 31, 2016		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ (4)	Operating revenue
Interest rate contracts	2	Interest and related charges
Foreign currency contracts	17	Other income
Total	15	
Tax	(6)	Income tax expense
Total, net of tax	$ 9	
Unrecognized pension costs:		
Actuarial losses	$ 5	Other operations and maintenance
Total	5	
Tax	(2)	Income tax expense
Total, net of tax	$ 3	

Stock-Based Awards

The 2005 and 2014 Incentive Compensation Plans permit stock-based awards that include restricted stock, performance grants, goal-based stock, stock options, and stock appreciation rights. The Non-Employee Directors Compensation Plan permits grants of restricted stock and stock options. Under provisions of these plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the CGN Committee of the Board of Directors or the Board of Directors itself, as provided under each plan. At December 31, 2017, approximately 23 million shares were available for future grants under these plans.

Goal-based stock awards are granted in lieu of cash-based performance grants to certain officers who have not achieved a certain targeted level of share ownership. As of December 31, 2017, unrecognized compensation cost related to nonvested goal-based stock awards was immaterial.

Dominion Energy measures and recognizes compensation expense relating to share-based payment transactions over the vesting period based on the fair value of the equity or liability instruments issued. Dominion Energy's results for the years ended December 31, 2017, 2016 and 2015 include $45 million, $33 million, and $39 million, respectively, of compensation costs and $16 million, $11 million, and $14 million, respectively of income tax benefits related to Dominion Energy's stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in Dominion Energy's Consolidated Statements of Income. Excess Tax Benefits are classified as a financing cash flow.

RESTRICTED STOCK

Restricted stock grants are made to officers under Dominion Energy's LTIP and may also be granted to certain key non-officer employees from time to time. The fair value of Dominion Energy's restricted stock awards is equal to the closing price of Dominion Energy's stock on the date of grant. New shares are issued for restricted stock awards on the date of grant and generally vest over a three-year service period. The following table provides a summary of restricted stock activity for the years ended December 31, 2017, 2016 and 2015:

	Shares	Weighted - average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2014	1,065	$56.74
Granted	302	73.26
Vested	(510)	50.71
Cancelled and forfeited	(2)	62.62
Nonvested at December 31, 2015	855	$66.16
Granted	372	71.67
Vested	(301)	56.83
Cancelled and forfeited	(40)	71.75
Nonvested at December 31, 2016	886	$71.40
Granted	**454**	**74.24**
Vested	**(287)**	**68.90**
Cancelled and forfeited	**(10)**	**72.37**
Nonvested at December 31, 2017	**1,043**	**$73.32**

As of December 31, 2017, unrecognized compensation cost related to nonvested restricted stock awards totaled $42 million and is expected to be recognized over a weighted-average period of 2.0 years. The fair value of restricted stock awards that vested was $21 million, $21 million, and $37 million in 2017, 2016 and 2015, respectively. Employees may elect to have shares of restricted stock withheld upon vesting to satisfy tax withholding obligations. The number of shares withheld will vary for each employee depending on the vesting date fair market value of Dominion Energy stock and the applicable federal, state and local tax withholding rates.

CASH-BASED PERFORMANCE GRANTS

Cash-based performance grants are made to Dominion Energy's officers under Dominion Energy's LTIP. The actual payout of cash-based performance grants will vary between zero and 200%

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of the targeted amount based on the level of performance metrics achieved.

In February 2015, a cash-based performance grant was made to officers. Payout of the performance grant occurred in January 2017 based on the achievement of two performance metrics during 2015 and 2016: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total of the payout under the grant was $10 million.

In February 2016, a cash-based performance grant was made to officers. Payout of the performance grant occurred in January 2018 based on the achievement of two performance metrics during 2016 and 2017: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total of the payout under the grant was $12 million.

In February 2017, two cash-based performance grants were made to officers as the Company transitioned from a two-year performance period to a three-year performance period. Payout of the two-year grant is expected to occur by March 15, 2019 based on the achievement of two performance metrics during 2017 and 2018: TSR relative to that of companies that are members of the Company's compensation peer group and ROIC. At December 31, 2017, the targeted amount of the two-year grant was $15 million and a liability of $7 million had been accrued for this award. Payout of the three-year cash-based performance grant is expected to occur by March 15, 2020 based on the achievement of two performance metrics during 2017, 2018 and 2019: TSR relative to that of companies that are members of the Company's compensation peer group and ROIC. At December 31, 2017, the targeted amount of the three-year grant was $15 million and a liability of $5 million had been accrued for the award.

NOTE 20. DIVIDEND RESTRICTIONS

The Virginia Commission may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2017, the Virginia Commission had not restricted the payment of dividends by Virginia Power.

The Ohio Commission may prohibit any public service company, including East Ohio, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2017, the Ohio Commission had not restricted the payment of dividends by East Ohio.

The Utah Commission may prohibit any public service company, including Questar Gas, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2017, the Utah Commission had not restricted the payment of dividends by Questar Gas.

Certain agreements associated with the Companies' credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict the Companies' ability to pay dividends or receive dividends from their subsidiaries at December 31, 2017.

As part of the SCANA Merger Agreement, Dominion Energy shall not declare, set aside or pay any dividends on, or make any other distributions (whether in cash, stock or property) in respect of, any of its capital stock, other than regular quarterly cash dividends.

See Note 17 for a description of potential restrictions on dividend payments by Dominion Energy in connection with the deferral of interest payments on certain junior subordinated notes and equity units, initially in the form of corporate units.

NOTE 21. EMPLOYEE BENEFIT PLANS

Dominion Energy and Dominion Energy Gas—Defined Benefit Plans

Dominion Energy provides certain retirement benefits to eligible active employees, retirees and qualifying dependents. Dominion Energy Gas participates in a number of the Dominion Energy-sponsored retirement plans. Under the terms of its benefit plans, Dominion Energy reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

Dominion Energy maintains qualified noncontributory defined benefit pension plans covering virtually all employees. Retirement benefits are based primarily on years of service, age and the employee's compensation. Dominion Energy's funding policy is to contribute annually an amount that is in accordance with the provisions of ERISA. The pension programs also provide benefits to certain retired executives under company-sponsored nonqualified employee benefit plans. The nonqualified plans are funded through contributions to grantor trusts. Dominion Energy also provides retiree healthcare and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service.

Pension benefits for Dominion Energy Gas employees not represented by collective bargaining units are covered by the Dominion Energy Pension Plan, a defined benefit pension plan sponsored by Dominion Energy that provides benefits to multiple Dominion Energy subsidiaries. Pension benefits for Dominion Energy Gas employees represented by collective bargaining units are covered by separate pension plans for East Ohio and, for DETI, a plan that provides benefits to employees of both DETI and Hope. Employee compensation is the basis for allocating pension costs and obligations between DETI and Hope and determining East Ohio's share of total pension costs.

Retiree healthcare and life insurance benefits for Dominion Energy Gas employees not represented by collective bargaining units are covered by the Dominion Retiree Health and Welfare Plan, a plan sponsored by Dominion Energy that provides certain retiree healthcare and life insurance benefits to multiple Dominion Energy subsidiaries. Retiree healthcare and life insurance benefits for Dominion Energy Gas employees represented by collective bargaining units are covered by separate other postretirement benefit plans for East Ohio and, for DETI, a plan that provides benefits to both DETI and Hope. Employee headcount is the basis for allocating other postretirement benefit costs and obligations between DETI and Hope and determining East Ohio's share of total other postretirement benefit costs.

Pension and other postretirement benefit costs are affected by employee demographics (including age, compensation levels and years of service), the level of contributions made to the plans and

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earnings on plan assets. These costs may also be affected by changes in key assumptions, including expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates, mortality rates and the rate of compensation increases.

Dominion Energy uses December 31 as the measurement date for all of its employee benefit plans, including those in which Dominion Energy Gas participates. Dominion Energy uses the market-related value of pension plan assets to determine the expected return on plan assets, a component of net periodic pension cost, for all pension plans, including those in which Dominion Energy Gas participates. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period, which reduces year-to-year volatility. Changes in fair value are measured as the difference between the expected and actual plan asset returns, including dividends, interest and realized and unrealized investment gains and losses. Since the market-related value recognizes changes in fair value over a four-year period, the future market-related value of pension plan assets will be impacted as previously unrecognized changes in fair value are recognized.

Dominion Energy's pension and other postretirement benefit plans hold investments in trusts to fund employee benefit payments. Dominion Energy's pension and other postretirement plan assets experienced aggregate actual returns of $1.6 billion and $534 million in 2017 and 2016, respectively, versus expected returns of $767 million and $691 million, respectively. Dominion Energy Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $335 million and $130 million in 2017 and 2016, respectively, versus expected returns of $165 million and $157 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans.

In October 2014, the Society of Actuaries published new mortality tables and mortality improvement scales. Such tables and scales are used to develop mortality assumptions for use in determining pension and other postretirement benefit liabilities and expense. Following evaluation of the new tables, Dominion Energy changed its assumption for mortality rates to reflect a generational improvement scale. This change in assumption increased net periodic benefit cost for Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units) by $25 million and $3 million, respectively, for 2015.

During 2016, Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units) engaged their actuary to conduct an experience study of their employees demographics over a five-year period as compared to significant assumptions that were being used to determine pension and other postretirement benefit obligations and periodic costs. These assumptions primarily included mortality, retirement rates, termination rates, and salary increase rates. The changes in assumptions implemented as a result of the experience study resulted in increases of $290 million and $38 million in the pension and other postretirement benefits obligations, respectively, at December 31, 2016 for Dominion Energy and $24 million and $9 million in the pension and other postretirement benefits obligations, respectively, at December 31, 2016 for Dominion Energy Gas. In addition, these changes increased net periodic benefit costs $42 million for Dominion Energy during 2017. The increase in net periodic benefit costs for Dominion Energy Gas during 2017 was immaterial.

PLAN AMENDMENTS AND REMEASUREMENTS

In the fourth quarter of 2017, Dominion Energy remeasured its pension and other postretirement benefit plans as a result of voluntary and involuntary separation programs at Dominion Energy Questar. The settlement and related remeasurement resulted in a reduction in the pension benefit obligation of approximately $75 million and an increase in the accumulated postretirement benefit obligation of approximately $2 million. The discount rates used for the 2017 pension cost and related settlement were 4.46% as of December 31, 2016, 4.51% as of January 31, 2017 and 4.05% as of June 30 and September 30, 2017. All other assumptions used were consistent with the measurement as of December 31, 2016.

In the first quarter of 2017, Dominion Energy and Dominion Energy Gas remeasured an other postretirement benefit plan as a result of an amendment that changed post-65 retiree medical coverage for certain current and future Local 69 retirees effective July 1, 2017. The remeasurement resulted in a decrease in Dominion Energy's and Dominion Energy Gas' accumulated postretirement benefit obligation of $73 million and $61 million, respectively. As a result of regulatory accounting, the remeasurement had an immaterial impact on net income for both Dominion Energy and Dominion Energy Gas. The discount rate used for the remeasurement was 4.30%. All other assumptions used were consistent with the measurement as of December 31, 2016.

Also during the first quarter of 2017, Dominion Energy recorded a $7 million ($4 million after-tax) charge, including $6 million ($4 million after-tax) at Dominion Energy Gas, as a result of additional payments associated with the new collective bargaining agreement, which is reflected in other operations and maintenance expense in their Consolidated Statements of Income.

In the third quarter of 2016, Dominion Energy remeasured an other postretirement benefit plan as a result of an amendment that changed post-65 retiree medical coverage for certain current and future Local 50 retirees effective April 1, 2017. The remeasurement resulted in a decrease in Dominion Energy's accumulated postretirement benefit obligation of $37 million. The impact of the remeasurement on net periodic benefit credit was recognized prospectively from the remeasurement date and increased the net periodic benefit credit for 2016 by $9 million. The discount rate used for the remeasurement was 3.71% and the demographic and mortality assumptions were updated using plan-specific studies and mortality improvement scales. The expected long-term rate of return used was consistent with the measurement as of December 31, 2015.

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FUNDED STATUS

The following table summarizes the changes in pension plan and other postretirement benefit plan obligations and plan assets and includes a statement of the plans' funded status for Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
Year Ended December 31,	**2017**	2016	**2017**	2016
(millions, except percentages)				
Dominion Energy				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 8,132**	$ 6,391	**$ 1,478**	$ 1,430
Dominion Energy Questar Combination	**—**	817	**—**	85
Service cost	**138**	118	**26**	31
Interest cost	**345**	317	**60**	65
Benefits paid	**(323)**	(286)	**(83)**	(83)
Actuarial (gains) losses during the year	**830**	784	**119**	166
Plan amendments(1)	**5**	—	**(73)**	(216)
Settlements and curtailments(2)	**(75)**	(9)	**2**	—
Benefit obligation at end of year	**$ 9,052**	$ 8,132	**$ 1,529**	$ 1,478
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 7,016**	$ 6,166	**$ 1,512**	$ 1,382
Dominion Energy Questar Combination	**—**	704	**—**	45
Actual return (loss) on plan assets	**1,327**	426	**236**	108
Employer contributions	**118**	15	**13**	12
Benefits paid	**(323)**	(286)	**(32)**	(35)
Settlements(2)	**(76)**	(9)	**—**	—
Fair value of plan assets at end of year	**$ 8,062**	$ 7,016	**$ 1,729**	$ 1,512
Funded status at end of year	**$ (990)**	$ (1,116)	**$ 200**	$ 34
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$ 1,117**	$ 930	**$ 261**	$ 148
Other current liabilities	**(8)**	(43)	**—**	(5)
Noncurrent pension and other postretirement benefit liabilities	**(2,099)**	(2,003)	**(61)**	(109)
Net amount recognized	**$ (990)**	$ (1,116)	**$ 200**	$ 34
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**3.80%–3.81%**	3.31%–4.50%	**3.76%**	3.92%–4.47%
Weighted average rate of increase for compensation	**4.09%**	4.09%	**3.95%-4.11%**	3.29%
Dominion Energy Gas				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 683**	$ 608	**$ 320**	$ 292
Service cost	**15**	13	**4**	5
Interest cost	**30**	30	**12**	14
Benefits paid	**(33)**	(32)	**(19)**	(19)
Actuarial (gains) losses during the year	**78**	64	**34**	28
Plan amendments(1)	**—**	—	**(61)**	—
Benefit obligation at end of year	**$ 773**	$ 683	**$ 290**	$ 320
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 1,542**	$ 1,467	**$ 299**	$ 283
Actual return (loss) on plan assets	**294**	107	**41**	23
Employer contributions	**—**	—	**12**	12
Benefits paid	**(33)**	(32)	**(19)**	(19)
Fair value of plan assets at end of year	**$ 1,803**	$ 1,542	**$ 333**	$ 299
Funded status at end of year	**$ 1,030**	$ 859	**$ 43**	$ (21)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$ 1,030**	$ 859	**$ 57**	$ —
Noncurrent pension and other postretirement benefit liabilities(3)	**—**	—	**(14)**	(21)
Net amount recognized	**$ 1,030**	$ 859	**$ 43**	$ (21)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**3.81%**	4.50%	**3.76%**	4.47%
Weighted average rate of increase for compensation	**4.11%**	4.11%	**n/a**	n/a

(1) 2017 amounts relate primarily to a plan amendment that changed post-65 retiree medical coverage for certain current and future Local 69 retirees effective July 1, 2017. 2016 amount relates primarily to a plan amendment that changed post-65 retiree medical coverage for certain current and future Local 50 retirees effective April 1, 2017.

(2) 2017 amount relates primarily to settlement and curtailment as a result of the voluntary and involuntary separation programs at Dominion Energy Questar. 2016 amount relates primarily to a settlement for certain executives.

(3) Reflected in other deferred credits and other liabilities in Dominion Energy Gas' Consolidated Balance Sheets.

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The ABO for all of Dominion Energy's defined benefit pension plans was $8.2 billion and $7.3 billion at December 31, 2017 and 2016, respectively. The ABO for the defined benefit pension plans covering Dominion Energy Gas employees represented by collective bargaining units was $724 million and $640 million at December 31, 2017 and 2016, respectively.

Under its funding policies, Dominion Energy evaluates plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from its actuary. Based on the funded status of each plan and other factors, Dominion Energy determines the amount of contributions for the current year, if any, at that time. During 2017, Dominion Energy and Dominion Energy Gas made no contributions to the qualified defined benefit pension plans other than a $75 million contribution to Dominion Energy's qualified pension plan to satisfy a regulatory condition to closing of the Dominion Energy Questar Combination and no contributions are currently expected in 2018. In July 2012, the MAP 21 Act was signed into law. This Act includes an increase in the interest rates used to determine plan sponsors' pension contributions for required funding purposes. In 2014, the HATFA of 2014 was signed into law. Similar to the MAP 21 Act, the HATFA of 2014 adjusts the rules for calculating interest rates used in determining funding obligations. It is estimated that the new interest rates will reduce required pension contributions through 2019. Dominion Energy believes that required pension contributions will rise subsequent to 2019, resulting in an estimated $200 million reduction in net cumulative required contributions over a 10-year period.

Certain regulatory authorities have held that amounts recovered in utility customers' rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain of Dominion Energy's subsidiaries, including Dominion Energy Gas, fund other postretirement benefit costs through VEBAs. Dominion Energy's remaining subsidiaries do not prefund other postretirement benefit costs but instead pay claims as presented. Dominion Energy's contributions to VEBAs, all of which pertained to Dominion Energy Gas employees, totaled $12 million for both 2017 and 2016, and Dominion Energy expects to contribute approximately $12 million to the Dominion Energy VEBAs in 2018, all of which pertains to Dominion Energy Gas employees.

Dominion Energy and Dominion Energy Gas do not expect any pension or other postretirement plan assets to be returned during 2018.

The following table provides information on the benefit obligations and fair value of plan assets for plans with a benefit obligation in excess of plan assets for Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	**2017**	2016	**2017**	2016
(millions)				
Dominion Energy				
Benefit obligation	**$8,209**	$7,386	**$191**	$470
Fair value of plan assets	**6,103**	5,340	**156**	356
Dominion Energy Gas				
Benefit obligation	**$ —**	$ —	**$157**	$320
Fair value of plan assets	**—**	—	**143**	299

The following table provides information on the ABO and fair value of plan assets for Dominion Energy's pension plans with an ABO in excess of plan assets:

As of December 31,	**2017**	2016
(millions)		
Accumulated benefit obligation	**$7,392**	$5,987
Fair value of plan assets	**6,103**	4,653

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans:

	Estimated Future Benefit Payments	
	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion Energy		
2018	**$373**	**$ 99**
2019	**378**	**101**
2020	**402**	**102**
2021	**418**	**102**
2022	**434**	**102**
2023-2027	**2,437**	**486**
Dominion Energy Gas		
2018	**$ 35**	**$ 19**
2019	**37**	**19**
2020	**38**	**20**
2021	**39**	**20**
2022	**41**	**20**
2023-2027	**214**	**94**

PLAN ASSETS

Dominion Energy's overall objective for investing its pension and other postretirement plan assets is to achieve appropriate long-term rates of return commensurate with prudent levels of risk. As a participating employer in various pension plans sponsored by Dominion Energy, Dominion Energy Gas is subject to Dominion Energy's investment policies for such plans. To minimize risk, funds are broadly diversified among asset classes, investment strategies and investment advisors. The strategic target asset allocations for Dominion Energy's pension funds are 28% U.S. equity, 18% non-U.S. equity, 35% fixed income, 3% real estate and 16% other alternative investments. U.S. equity includes investments in large-cap, mid-cap and small-cap companies located in the U.S. Non-U.S. equity includes investments in large-cap and small-cap companies located outside of the U.S. including both developed and emerging markets. Fixed income includes corporate debt instruments of companies from diversified industries and U.S. Treasuries. The U.S. equity, non-U.S. equity and fixed income investments are in individual securities as well as mutual funds. Real estate includes equity real estate investment trusts and investments in partnerships. Other alternative investments include partnership investments in private equity, debt and hedge funds that follow several different strategies.

Dominion Energy also utilizes common/collective trust funds as an investment vehicle for its defined benefit plans. A common/collective trust fund is a pooled fund operated by a bank or trust company for investment of the assets of various organizations and

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individuals in a well-diversified portfolio. Common/collective trust funds are funds of grouped assets that follow various investment strategies.

Strategic investment policies are established for Dominion Energy's prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of Dominion Energy's assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns. Financial derivatives may be used to obtain or manage market exposures and to hedge assets and liabilities.

For fair value measurement policies and procedures related to pension and other postretirement benefit plan assets, see Note 6.

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The fair values of Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) pension plan assets by asset category are as follows:

At December 31,	2017				2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(millions)								
Dominion Energy								
Cash and cash equivalents	**$ 18**	**$ —**	**$—**	**$ 18**	$ 12	$ 2	$—	$ 14
Common and preferred stocks:								
U.S.	**1,902**	**—**	**—**	**1,902**	1,705	—	—	1,705
International	**1,151**	**—**	**—**	**1,151**	928	—	—	928
Insurance contracts	**—**	**352**	**—**	**352**	—	334	—	334
Corporate debt instruments	**41**	**729**	**—**	**770**	35	682	—	717
Government securities	**9**	**676**	**—**	**685**	13	522	—	535
Total recorded at fair value	**$3,121**	**$1,757**	**$—**	**$4,878**	$2,693	$1,540	$—	$4,233
Assets recorded at NAV(1):								
Common/collective trust funds				**2,272**				1,960
Alternative investments:								
Real estate funds				**111**				121
Private equity funds				**606**				506
Debt funds				**161**				153
Hedge funds				**19**				25
Total recorded at NAV				**$3,169**				$2,765
Total investments(2)				**$8,047**				$6,998
Dominion Energy Gas								
Cash and cash equivalents	**$ 4**	**$ —**	**$—**	**$ 4**	$ 3	$ —	$—	$ 3
Common and preferred stocks:								
U.S.	**425**	**—**	**—**	**425**	375	—	—	375
International	**257**	**—**	**—**	**257**	203	—	—	203
Insurance contracts	**—**	**79**	**—**	**79**	—	73	—	73
Corporate debt instruments	**9**	**163**	**—**	**172**	8	150	—	158
Government securities	**2**	**151**	**—**	**153**	3	115	—	118
Total recorded at fair value	**$ 697**	**$ 393**	**$—**	**$1,090**	$ 592	$ 338	$—	$ 930
Assets recorded at NAV(1):								
Common/collective trust funds				**509**				430
Alternative investments:								
Real estate funds				**25**				27
Private equity funds				**135**				111
Debt funds				**36**				34
Hedge funds				**4**				6
Total recorded at NAV				**$ 709**				$ 608
Total investments(3)				**$1,799**				$1,538

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

(2) Excludes net assets related to pending sales of securities of $11 million, net accrued income of $19 million, and includes net assets related to pending purchases of securities of $15 million at December 31, 2017. Excludes net assets related to pending sales of securities of $46 million, net accrued income of $19 million, and includes net assets related to pending purchases of securities of $47 million at December 31, 2016.

(3) Excludes net assets related to pending sales of securities of $3 million, net accrued income of $4 million, and includes net assets related to pending purchases of securities of $3 million at December 31, 2017. Excludes net assets related to pending sales of securities of $10 million, net accrued income of $4 million, and includes net assets related to pending purchases of securities of $10 million at December 31, 2016.

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The fair values of Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) other postretirement plan assets by asset category are as follows:

At December 31,	2017				2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(millions)								
Dominion Energy								
Cash and cash equivalents	**$ 1**	**$ 2**	**$—**	**$ 3**	$ 1	$ 1	$—	$ 2
Common and preferred stocks:								
U.S.	**636**	**—**	**—**	**636**	571	—	—	571
International	**196**	**—**	**—**	**196**	143	—	—	143
Insurance contracts	**—**	**21**	**—**	**21**	—	19	—	19
Corporate debt instruments	**2**	**44**	**—**	**46**	2	40	—	42
Government securities	**1**	**41**	**—**	**42**	1	30	—	31
Total recorded at fair value	**$836**	**$108**	**$—**	**$ 944**	$718	$90	$—	$ 808
Assets recorded at NAV(1):								
Common/collective trust funds				**689**				621
Alternative investments:								
Real estate funds				**9**				9
Private equity funds				**73**				59
Debt funds				**11**				12
Hedge funds				**1**				1
Total recorded at NAV				**$ 783**				$ 702
Total investments(2)				**$1,727**				$1,510
Dominion Energy Gas								
Common and preferred stocks:								
U.S.	**$130**	**$ —**	**$—**	**$ 130**	$121	$—	$—	$ 121
International	**33**	**—**	**—**	**33**	24	—	—	24
Total recorded at fair value	**$163**	**$ —**	**$—**	**$ 163**	$145	$—	$—	$ 145
Assets recorded at NAV(1):								
Common/collective trust funds				**154**				140
Alternative investments:								
Real estate funds				**1**				1
Private equity funds				**15**				12
Debt funds				**—**				1
Total recorded at NAV				**$ 170**				$ 154
Total investments				**$ 333**				$ 299

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

(2) Excludes net assets related to pending sales of securities of $1 million, net accrued income of $2 million, and includes net assets related to pending purchases of securities of $1 million at December 31, 2017. Excludes net assets related to pending sales of securities of $5 million, net accrued income of $2 million, and includes net assets related to pending purchases of securities of $5 million at December 31, 2016.

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The Plan's investments are determined based on the fair values of the investments and the underlying investments, which have been determined as follows:

- *Cash and Cash Equivalents*—Investments are held primarily in short-term notes and treasury bills, which are valued at cost plus accrued interest.
- *Common and Preferred Stocks*—Investments are valued at the closing price reported on the active market on which the individual securities are traded.
- *Insurance Contracts*—Investments in Group Annuity Contracts with John Hancock were entered into after 1992 and are stated at fair value based on the fair value of the underlying securities as provided by the managers and include investments in U.S. government securities, corporate debt instruments, state and municipal debt securities.
- *Corporate Debt Instruments*—Investments are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings. When quoted prices are not available for identical or similar instruments, the instrument is valued under a discounted cash flows approach that maximizes observable inputs, such as current yields of similar instruments, but includes adjustments for certain risks that may not be observable, such as credit and liquidity risks or a broker quote, if available.
- *Government Securities*—Investments are valued using pricing models maximizing the use of observable inputs for similar securities.
- *Common/Collective Trust Funds*—Common/collective trust funds invest in debt and equity securities and other instruments with characteristics similar to those of the funds' benchmarks. The primary objectives of the funds are to seek investment returns that approximate the overall performance of their benchmark indexes. These benchmarks are major equity indices, fixed income indices, and money market indices that focus on growth, income, and liquidity strategies, as applicable. Investments in common/collective trust funds are stated at the NAV as determined by the issuer of the common/collective trust funds and are based on the fair value of the underlying investments held by the fund less its liabilities. The NAV is used as a practical expedient to estimate fair value. The common/collective trust funds do not have any unfunded commitments, and do not have any applicable liquidation periods or defined terms/periods to be held. The majority of the common/collective trust funds have limited withdrawal or redemption rights during the term of the investment.
- *Alternative Investments*—Investments in real estate funds, private equity funds, debt funds and hedge funds are stated at fair value based on the NAV of the Plan's proportionate share of the partnership, joint venture or other alternative investment's fair value as determined by reference to audited financial statements or NAV statements provided by the investment manager. The NAV is used as a practical expedient to estimate fair value.

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Combined Notes to Consolidated Financial Statements, Continued

NET PERIODIC BENEFIT (CREDIT) COST

Net periodic benefit (credit) cost is reflected in other operations and maintenance expense in the Consolidated Statements of Income. The components of the provision for net periodic benefit (credit) cost and amounts recognized in other comprehensive income and regulatory assets and liabilities for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2017**	2016	2015	**2017**	2016	2015
(millions, except percentages)						
Dominion Energy						
Service cost	**$ 138**	$ 118	$ 126	**$ 26**	$ 31	$ 40
Interest cost	**345**	317	287	**60**	65	67
Expected return on plan assets	**(639)**	(573)	(531)	**(128)**	(118)	(117)
Amortization of prior service (credit) cost	**1**	1	2	**(51)**	(35)	(27)
Amortization of net actuarial loss	**162**	111	160	**13**	8	6
Settlements and curtailments	**—**	1	—	**—**	—	—
Net periodic benefit (credit) cost	**$ 7**	$ (25)	$ 44	**$ (80)**	$ (49)	$ (31)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 142**	$ 931	$ 159	**$ 12**	$ 178	$ (18)
Prior service (credit) cost	**5**	—	—	**(73)**	(216)	(31)
Settlements and curtailments	**1**	(1)	—	**2**	—	—
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(162)**	(111)	(160)	**(13)**	(8)	(6)
Amortization of prior service credit (cost)	**(1)**	(1)	(2)	**51**	35	27
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ (15)**	$ 818	$ (3)	**$ (21)**	$ (11)	$ (28)
Significant assumptions used to determine periodic cost:						
Discount rate	**3.31%-4.50%**	2.87%-4.99%	4.40%	**3.92%-4.47%**	3.56%-4.94%	4.40%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.75%	**8.50%**	8.50%	8.50%
Weighted average rate of increase for compensation	**4.09%**	4.22%	4.22%	**3.29%**	4.22%	4.22%
Healthcare cost trend rate(1)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(1)				**5.00%**	5.00%	5.00%
Year that the rate reaches the ultimate trend rate(1)(2)				**2021**	2020	2019
Dominion Energy Gas						
Service cost	**$ 15**	$ 13	$ 15	**$ 4**	$ 5	$ 7
Interest cost	**30**	30	27	**12**	14	14
Expected return on plan assets	**(141)**	(134)	(126)	**(24)**	(23)	(24)
Amortization of prior service (credit) cost	**—**	—	1	**(3)**	1	(1)
Amortization of net actuarial loss	**16**	13	20	**2**	1	2
Net periodic benefit (credit) cost	**$ (80)**	$ (78)	$ (63)	**$ (9)**	$ (2)	$ (2)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ (75)**	$ 91	$ 97	**$ 18**	$ 28	$ (9)
Prior service cost	**—**	—	—	**(61)**	—	—
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(16)**	(13)	(20)	**(2)**	(1)	(2)
Amortization of prior service credit (cost)	**—**	—	(1)	**3**	(1)	1
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ (91)**	$ 78	$ 76	**$ (42)**	$ 26	$ (10)
Significant assumptions used to determine periodic cost:						
Discount rate	**4.50%**	4.99%	4.40%	**4.47%**	4.93%	4.40%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.75%	**8.50%**	8.50%	8.50%
Weighted average rate of increase for compensation	**4.11%**	3.93%	3.93%	**4.11%**	3.93%	3.93%
Healthcare cost trend rate(1)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(1)				**5.00%**	5.00%	5.00%
Year that the rate reaches the ultimate trend rate(1)				**2021**	2020	2019

(1) Assumptions used to determine net periodic cost for the following year.
(2) The Society of Actuaries model used to determine healthcare cost trend rates was updated in 2014. The new model converges to the ultimate trend rate much more quickly than previous models.

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The components of AOCI and regulatory assets and liabilities for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans that have not been recognized as components of net periodic benefit (credit) cost are as follows:

At December 31,	Pension Benefits 2017	Pension Benefits 2016	Other Postretirement Benefits 2017	Other Postretirement Benefits 2016
(millions)				
Dominion Energy				
Net actuarial loss	**$3,181**	$3,200	**$ 283**	$ 283
Prior service (credit) cost	**8**	4	**(440)**	(419)
Total(1)	**$3,189**	$3,204	**$(157)**	$(136)
Dominion Energy Gas				
Net actuarial loss	**$ 367**	$ 458	**$ 76**	$ 60
Prior service (credit) cost	**—**	—	**(52)**	7
Total(2)	**$ 367**	$ 458	**$ 24**	$ 67

(1) As of December 31, 2017, of the $3.2 billion and $(157) million related to pension benefits and other postretirement benefits, $1.9 billion and $(87) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities. As of December 31, 2016, of the $3.2 billion and $(136) million related to pension benefits and other postretirement benefits, $1.9 billion and $(103) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities.

(2) As of December 31, 2017, of the $367 million related to pension benefits, $134 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $24 million related to other postretirement benefits is included entirely in regulatory assets and liabilities. As of December 31, 2016, of the $458 million related to pension benefits, $167 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $67 million related to other postretirement benefits is included entirely in regulatory assets and liabilities.

The following table provides the components of AOCI and regulatory assets and liabilities for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans as of December 31, 2017 that are expected to be amortized as components of net periodic benefit (credit) cost in 2018:

	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion Energy		
Net actuarial loss	**$193**	**$ 11**
Prior service (credit) cost	**1**	**(52)**
Dominion Energy Gas		
Net actuarial loss	**$ 19**	**$ 3**
Prior service (credit) cost	**—**	**(4)**

The expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and mortality are critical assumptions in determining net periodic benefit (credit) cost. Dominion Energy develops non-investment related assumptions, which are then compared to the forecasts of an independent investment advisor to ensure reasonableness. An internal committee selects the final assumptions used for Dominion Energy's pension and other postretirement plans, including those in which Dominion Energy Gas participates, including discount rates, expected long-term rates of return, healthcare cost trend rates and mortality rates.

Dominion Energy determines the expected long-term rates of return on plan assets for its pension plans and other postretirement benefit plans, including those in which Dominion Energy Gas participates, by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset volatilities and correlations;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major stock market indices; and
- Investment allocation of plan assets.

Dominion Energy determines discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under its plans, including those in which Dominion Energy Gas participates.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion Energy's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion Energy considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion Energy conducted a new experience study as scheduled and, as a result, updated its mortality assumptions for all its plans, including those in which Dominion Energy Gas participates.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for Dominion Energy's retiree healthcare plans, including those in which Dominion Energy Gas participates. A one percentage point change in assumed healthcare cost trend rates would have had the following effects for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) other postretirement benefit plans:

	Other Postretirement Benefits One percentage point increase	Other Postretirement Benefits One percentage point decrease
(millions)		
Dominion Energy		
Effect on net periodic cost for 2018	**$ 24**	**$ (15)**
Effect on other postretirement benefit obligation at December 31, 2017	**158**	**(132)**
Dominion Energy Gas		
Effect on net periodic cost for 2018	**$ 4**	**$ (3)**
Effect on other postretirement benefit obligation at December 31, 2017	**31**	**(26)**

Dominion Energy Gas (Employees Not Represented by Collective Bargaining Units) and Virginia Power—Participation in Defined Benefit Plans

Virginia Power employees and Dominion Energy Gas employees not represented by collective bargaining units are covered by the Dominion Energy Pension Plan described above. As participating employers, Virginia Power and Dominion Energy Gas are subject to Dominion Energy's funding policy, which is to contribute annually an amount that is in accordance with ERISA. During 2017, Virginia Power and Dominion Energy Gas made no con-

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tributions to the Dominion Energy Pension Plan, and no contributions to this plan are currently expected in 2018. Virginia Power's net periodic pension cost related to this plan was $110 million, $79 million and $97 million in 2017, 2016 and 2015, respectively. Dominion Energy Gas' net periodic pension credit related to this plan was $(37) million, $(45) million and $(38) million in 2017, 2016 and 2015, respectively. Net periodic pension (credit) cost is reflected in other operations and maintenance expense in their respective Consolidated Statements of Income. The funded status of various Dominion Energy subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating Dominion Energy subsidiaries. See Note 24 for Virginia Power and Dominion Energy Gas amounts due to/from Dominion Energy related to this plan.

Retiree healthcare and life insurance benefits, for Virginia Power employees and for Dominion Energy Gas employees not represented by collective bargaining units, are covered by the Dominion Energy Retiree Health and Welfare Plan described above. Virginia Power's net periodic benefit (credit) cost related to this plan was $(42) million, $(29) million and $(16) million in 2017, 2016 and 2015, respectively. Dominion Energy Gas' net periodic benefit (credit) cost related to this plan was $(5) million, $(4) million and $(5) million for 2017, 2016 and 2015, respectively. Net periodic benefit (credit) cost is reflected in other operations and maintenance expenses in their respective Consolidated Statements of Income. Employee headcount is the basis for determining the share of total other postretirement benefit costs for participating Dominion Energy subsidiaries. See Note 24 for Virginia Power and Dominion Energy Gas amounts due to/from Dominion Energy related to this plan.

Dominion Energy holds investments in trusts to fund employee benefit payments for the pension and other postretirement benefit plans in which Virginia Power and Dominion Energy Gas' employees participate. Any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that Virginia Power and Dominion Energy Gas will provide to Dominion Energy for their shares of employee benefit plan contributions.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, Virginia Power and Dominion Energy Gas fund other postretirement benefit costs through VEBAs. During 2017 and 2016, Virginia Power made no contributions to the VEBA and does not expect to contribute to the VEBA in 2018. Dominion Energy Gas made no contributions to the VEBAs for employees not represented by collective bargaining units during 2017 and 2016 and does not expect to contribute in 2018.

Defined Contribution Plans

Dominion Energy also sponsors defined contribution employee savings plans that cover substantially all employees. During 2017, 2016 and 2015, Dominion Energy recognized $45 million, $44 million and $43 million, respectively, as employer matching contributions to these plans. Dominion Energy Gas participates in these employee savings plans, both specific to Dominion Energy Gas and that cover multiple Dominion Energy subsidiaries. During 2017, 2016 and 2015, Dominion Energy Gas recognized $7 million as employer matching contributions to these plans. Virginia Power also participates in these employee savings plans. During 2017, 2016 and 2015, Virginia Power recognized $19 million, $19 million and $18 million, respectively, as employer matching contributions to these plans.

Organizational Design Initiative

In the first quarter of 2016, the Companies announced an organizational design initiative that reduced their total workforces during 2016. The goal of the organizational design initiative was to streamline leadership structure and push decision making lower while also improving efficiency. For the year ended December 31, 2016, Dominion Energy recorded a $65 million ($40 million after-tax) charge, including $33 million ($20 million after-tax) at Virginia Power and $8 million ($5 million after-tax) at Dominion Energy Gas, primarily reflected in other operations and maintenance expense in their Consolidated Statements of Income due to severance pay and other costs related to the organizational design initiative. The terms of the severance under the organizational design initiative were consistent with the Companies' existing severance plans.

NOTE 22. COMMITMENTS AND CONTINGENCIES

As a result of issues generated in the ordinary course of business, the Companies are involved in legal proceedings before various courts and are periodically subject to governmental examinations (including by regulatory authorities), inquiries and investigations. Certain legal proceedings and governmental examinations involve demands for unspecified amounts of damages, are in an initial procedural phase, involve uncertainty as to the outcome of pending appeals or motions, or involve significant factual issues that need to be resolved, such that it is not possible for the Companies to estimate a range of possible loss. For such matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the litigation or investigative processes such that the Companies are able to estimate a range of possible loss. For legal proceedings and governmental examinations for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any accrued liability is recorded on a gross basis with a receivable also recorded for any probable insurance recoveries. Estimated ranges of loss are inclusive of legal fees and net of any anticipated insurance recoveries. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the Companies' maximum possible loss exposure. The circumstances of such legal proceedings and governmental examinations will change from time to time and actual results may vary significantly from the current estimate. For current proceedings not specifically reported below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial position, liquidity or results of operations of the Companies.

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Environmental Matters

The Companies are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

AIR

CAA

The CAA, as amended, is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

MATS

The MATS rule requires coal- and oil-fired electric utility steam generating units to meet strict emission limits for mercury, particulate matter as a surrogate for toxic metals and hydrogen chloride as a surrogate for acid gases. Following a one-year compliance extension granted by VDEQ and an additional one-year extension under an EPA Administrative Order, Virginia Power ceased operating the coal units at Yorktown power station in April 2017 to comply with the rule. In June 2017, the DOE issued an order to PJM to direct Virginia Power to operate Yorktown power station's Units 1 and 2 as needed to avoid reliability issues on the Virginia Peninsula. The order was effective for 90 days and can be reissued upon PJM's request, if necessary, until required electricity transmission upgrades are completed approximately 23 months following the receipt in July 2017 of final permits and approvals for construction. Beginning in August 2017, PJM filed requests for 90-day renewals of the DOE order which the DOE has granted. The current renewal is effective until March 2018. The Sierra Club has challenged the DOE order and certain renewal requests, all of which have been denied by the DOE.

Although litigation of the MATS rule is still pending, the regulation remains in effect and Virginia Power is complying with the applicable requirements of the rule and does not expect any adverse impacts to its operations at this time.

Ozone Standards

In October 2015, the EPA issued a final rule tightening the ozone standard from 75-ppb to 70-ppb. To comply with this standard, in April 2016 Virginia Power submitted the NO_X Reasonable Available Control Technology analysis for Unit 5 at Possum Point power station. In December 2016, the VDEQ determined that NO_X reductions are required on Unit 5. In October 2017, Virginia Power proposed to install NO_X controls by mid-2019 with an expected cost in the range of $25 million to $35 million.

The statutory deadline for the EPA to complete attainment designations for a new standard was October 2017. States will have three years after final designations, certain of which were issued by the EPA in November 2017, to develop plans to address the new standard. Until the states have developed implementation plans for the standard, the Companies are unable to predict whether or to what extent the new rules will ultimately require additional controls. The expenditures required to implement additional controls could have a material impact on the Companies' results of operations and cash flows.

NO_x and VOC Emissions

In April 2016, the Pennsylvania Department of Environmental Protection issued final regulations, with an effective date of January 2017, to reduce NO_X and VOC emissions from combustion sources. To comply with the regulations, Dominion Energy Gas is installing emission control systems on existing engines at several compressor stations in Pennsylvania. The compliance costs associated with engineering and installation of controls and compliance demonstration with the regulation are expected to be approximately $35 million.

Oil and Gas NSPS

In August 2012, the EPA issued an NSPS impacting new and modified facilities in the natural gas production and gathering sectors and made revisions to the NSPS for natural gas processing and transmission facilities. These rules establish equipment performance specifications and emissions standards for control of VOC emissions for natural gas production wells, tanks, pneumatic controllers, and compressors in the upstream sector. In June 2016, the EPA issued a new NSPS regulation, for the oil and natural gas sector, to regulate methane and VOC emissions from new and modified facilities in transmission and storage, gathering and boosting, production and processing facilities. All projects which commenced construction after September 2015 are required to comply with this regulation. In April 2017, the EPA issued a notice that it is reviewing the rule and, if appropriate, will issue a rulemaking to suspend, revise or rescind the June 2016 final NSPS for certain oil and gas facilities. In June 2017, the EPA published notice of reconsideration and partial stay of the rule for 90 days and proposed extending the stay for two years. In July 2017, the U.S. Court of Appeals for the D.C. Circuit vacated the 90-day stay. In November 2017, the EPA solicited comments on the proposed two-year stay of the June 2016 NSPS rules. Dominion Energy and Dominion Energy Gas are implementing the 2016 regulation. Dominion Energy and Dominion Energy Gas are still evaluating whether potential impacts on results of operations, financial condition and/or cash flows related to this matter will be material.

GHG REGULATION

Carbon Regulations

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a PSD or Title V permit for GHGs is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and to set a significant emissions rate at 75,000 tons per year of CO_2 equivalent emissions under which a source would not be required to apply BACT for its GHG emissions. Until the EPA ultimately takes final action on this rulemaking, the Companies cannot predict the impact to their financial statements.

In addition, the EPA continues to evaluate its policy regarding the consideration of CO_2 emissions from biomass projects when determining whether a stationary source meets the PSD and Title V applicability thresholds, including those for the application of

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BACT. It is unclear how the final policy will affect Virginia Power's Altavista, Hopewell and Southampton power stations which were converted from coal to biomass under the prior biomass deferral policy; however, the expenditures to comply with any new requirements could be material to Dominion Energy's and Virginia Power's financial statements.

Methane Emissions

In July 2015, the EPA announced the next generation of its voluntary Natural Gas STAR Program, the Natural Gas STAR Methane Challenge Program. The program covers the entire natural gas sector from production to distribution, with more emphasis on transparency and increased reporting for both annual emissions and reductions achieved through implementation measures. In March 2016, East Ohio, Hope, DETI and Questar Gas joined the EPA as founding partners in the new Methane Challenge program and submitted implementation plans in September 2016. DECG joined the EPA's voluntary Natural Gas STAR Program in July 2016 and submitted an implementation plan in September 2016. Dominion Energy and Dominion Energy Gas do not expect the costs related to these programs to have a material impact on their results of operations, financial condition and/or cash flows.

WATER

The CWA, as amended, is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. The Companies must comply with applicable aspects of the CWA programs at their operating facilities.

In October 2014, the final regulations under Section 316(b) of the CWA that govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold became effective. The rule establishes a national standard for impingement based on seven compliance options, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two MGD, with a heightened entrainment analysis for those facilities over 125 MGD. Dominion Energy and Virginia Power have 13 and 11 facilities, respectively, that may be subject to the final regulations. Dominion Energy anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. Dominion Energy and Virginia Power are currently evaluating the need or potential for entrainment controls under the final rule as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost and benefit studies. While the impacts of this rule could be material to Dominion Energy's and Virginia Power's results of operations, financial condition and/or cash flows, the existing regulatory framework in Virginia provides rate recovery mechanisms that could substantially mitigate any such impacts for Virginia Power.

In September 2015, the EPA released a final rule to revise the Effluent Limitations Guidelines for the Steam Electric Power Generating Category. The final rule establishes updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to convert from wet to dry or closed cycle coal ash management, improve existing wastewater treatment systems and/or install new wastewater treatment technologies in order to meet the new discharge limits. Virginia Power has eight facilities subject to the final rule. In April 2017, the EPA granted two separate petitions for reconsideration of the Effluent Limitations Guidelines final rule and stayed future compliance dates in the rule. Also in April 2017, the U.S. Court of Appeals for the Fifth Circuit granted the U.S.'s request for a stay of the pending consolidated litigation challenging the rule while the EPA addresses the petitions for reconsideration. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the Effluent Limitations Guidelines final rule from November 2018 to November 2020; however, the latest date for compliance for these regulations remains December 2023. The EPA is proposing to complete new rulemaking for these waste streams. While the impacts of this rule could be material to Dominion Energy's and Virginia Power's results of operations, financial condition and/or cash flows, the existing regulatory framework in Virginia provides rate recovery mechanisms that could substantially mitigate any such impacts for Virginia Power.

WASTE MANAGEMENT AND REMEDIATION

The CERCLA, as amended, provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under the CERCLA, as amended, generators and transporters of hazardous substances, as well as past and present owners and operators of contaminated sites, can be jointly, severally and strictly liable for the cost of cleanup. These potentially responsible parties can be ordered to perform a cleanup, be sued for costs associated with an EPA-directed cleanup, voluntarily settle with the U.S. government concerning their liability for cleanup costs, or voluntarily begin a site investigation and site remediation under state oversight.

From time to time, Dominion Energy, Virginia Power, or Dominion Energy Gas may be identified as a potentially responsible party to a Superfund site. The EPA (or a state) can either allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or conduct the remedial investigation and action itself and then seek reimbursement from the potentially responsible parties. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, Dominion Energy, Virginia Power, or Dominion Energy Gas may be responsible for the costs of remedial investigation and actions under the Superfund law or other laws or regulations regarding the remediation of waste. The Companies do not believe these matters will have a material effect on results of operations, financial condition and/or cash flows.

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Dominion Energy has determined that it is associated with 19 former manufactured gas plant sites, three of which pertain to Virginia Power and 12 of which pertain to Dominion Energy Gas. Studies conducted by other utilities at their former manufactured gas plant sites have indicated that those sites contain coal tar and other potentially harmful materials. None of the former sites with which the Companies are associated is under investigation by any state or federal environmental agency. At one of the former sites, Dominion Energy is conducting a state-approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. Another site has been accepted into a state-based voluntary remediation program. Virginia Power is currently evaluating the nature and extent of the contamination from this site as well as potential remedial options. Preliminary costs for options under evaluation for the site range from $1 million to $22 million. Due to the uncertainty surrounding the other sites, the Companies are unable to make an estimate of the potential financial statement impacts.

See below for discussion on ash pond and landfill closure costs.

Other Legal Matters

The Companies are defendants in a number of lawsuits and claims involving unrelated incidents of property damage and personal injury. Due to the uncertainty surrounding these matters, the Companies are unable to make an estimate of the potential financial statement impacts; however, they could have a material impact on results of operations, financial condition and/or cash flows.

APPALACHIAN GATEWAY

Pipeline Contractor Litigation

Following the completion of the Appalachian Gateway project in 2012, DETI received multiple change order requests and other claims for additional payments from a pipeline contractor for the project. In July 2015, the contractor filed a complaint against DETI in U.S. District Court for the Western District of Pennsylvania. In March 2016, the Pennsylvania court granted DETI's motion to transfer the case to the U.S. District Court for the Eastern District of Virginia. In July 2016, DETI filed a motion to dismiss. In March 2017, the court dismissed three of eight counts in the complaint. In May 2017, the contractor withdrew one of the counts in the complaint. In November 2017, DETI and the contractor entered into a partial settlement agreement for a release of certain claims. This case is pending. At December 31, 2017, DETI has accrued a liability of $2 million for this matter. Dominion Energy Gas cannot currently estimate additional financial statement impacts, but there could be a material impact to its financial condition and/or cash flows.

Gas Producers Litigation

In connection with the Appalachian Gateway project, Dominion Energy Field Services, Inc. entered into contracts for firm purchase rights with a group of small gas producers. In June 2016, the gas producers filed a complaint in the Circuit Court of Marshall County, West Virginia against Dominion Energy, DETI and Dominion Energy Field Services, Inc., among other defendants, claiming that the contracts are unenforceable and seeking compensatory and punitive damages. During the third quarter of 2016, Dominion Energy, DETI and Dominion Energy Field Services, Inc. were served with the complaint. Also in the third quarter of 2016, Dominion Energy and DETI, with the consent of the other defendants, removed the case to the U.S. District Court for the Northern District of West Virginia. In October 2016, the defendants filed a motion to dismiss and the plaintiffs filed a motion to remand. In February 2017, the U.S. District Court entered an order remanding the matter to the Circuit Court of Marshall County, West Virginia. In March 2017, Dominion Energy was voluntarily dismissed from the case; however, DETI and Dominion Energy Field Services, Inc. remain parties to the matter. In April 2017, the case was transferred to the Business Court Division of West Virginia. In January 2018, the court granted the motion to dismiss filed by the defendants on two counts. All other claims are pending in the Business Court Division of West Virginia. Dominion Energy and Dominion Energy Gas cannot currently estimate financial statement impacts, but there could be a material impact to their financial condition and/or cash flows.

ASH POND AND LANDFILL CLOSURE COSTS

In March 2015, the Sierra Club filed a lawsuit alleging CWA violations at Chesapeake power station. In March 2017, the U.S. District Court for the Eastern District of Virginia ruled that impacted groundwater associated with the on-site coal ash storage units was migrating to adjacent surface water, which constituted an unpermitted point source discharge in violation of the CWA. The court, however, rejected Sierra Club's claims that Virginia Power had violated specific conditions of its water discharge permit. Finding no harm to the environment, the court further declined to impose civil penalties or require excavation of the ash from the site as Sierra Club had sought. In July 2017, the court issued a final order requiring Virginia Power to perform additional specific sediment, water and aquatic life monitoring at and around the Chesapeake power station for a period of at least two years. The court further directed Virginia Power to apply for a solid waste permit from VDEQ that includes corrective measures to address on-site groundwater impacts. In July 2017, Virginia Power appealed the court's July 2017 final order to the U.S. Court of Appeals for the Fourth Circuit. In August 2017, the Sierra Club filed a cross appeal. This case is pending.

In April 2015, the EPA enacted a final rule regulating CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store, CCRs. Virginia Power currently operates inactive ash ponds, existing ash ponds, and CCR landfills subject to the final rule at eight different facilities. This rule created a legal obligation for Virginia Power to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary.

In 2015, Virginia Power recorded a $386 million ARO related to future ash pond and landfill closure costs, which resulted in a $99 million incremental charge recorded in other operations and maintenance expense in its Consolidated Statement of Income, a $166 million increase in property, plant and equipment associated with asset retirement costs, and a $121 million reduction in other noncurrent liabilities from the reversal of a previously recorded contingent liability since the ARO obligation created by the final CCR rule represents similar

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activities. In 2016, Virginia Power recorded an increase to this ARO of $238 million, which resulted in a $197 million incremental charge recorded in other operations and maintenance expense in its Consolidated Statement of Income, a $17 million increase in property, plant and equipment and a $24 million increase in regulatory assets.

In December 2016, legislation was enacted that creates a framework for EPA- approved state CCR permit programs. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. In September 2017, the EPA agreed to reconsider portions of the CCR rule in response to two petitions for reconsideration. Litigation concerning the CCR rule is pending and the EPA has submitted to the court a list of which CCR rule provisions the EPA intends to reevaluate. Virginia Power cannot forecast potential incremental impacts or costs related to existing coal ash sites in connection with future implementation of the 2016 CCR legislation and reconsideration of the CCR rule.

In April 2017, the Virginia Governor signed legislation into law that places a moratorium on the VDEQ issuing solid waste permits for closure of ash ponds at Virginia Power's Bremo, Chesapeake, Chesterfield and Possum Point power stations until May 2018. The law also required Virginia Power to conduct an assessment of closure alternatives for the ash ponds at these four stations, to include an evaluation of excavation for recycling or off-site disposal, surface and groundwater conditions and safety. Virginia Power completed the assessments and provided the report on December 1, 2017. The actual AROs related to the CCR rule may vary substantially from the estimates used to record the obligation.

COVE POINT

Dominion Energy has constructed the Liquefaction Project at the Cove Point facility, which, once commercially operational, would enable the facility to liquefy domestically-produced natural gas and export it as LNG. In September 2014, FERC issued an order granting authorization for Cove Point to construct, modify and operate the Liquefaction Project.

Two parties have separately filed petitions for review of the FERC order in the U.S. Court of Appeals for the D.C. Circuit, which petitions were consolidated. Separately, one party requested a stay of the FERC order until the judicial proceedings are complete, which the court denied in June 2015. In July 2016, the court denied one party's petition for review of the FERC order authorizing the Liquefaction Project. The court also issued a decision remanding the other party's petition for review of the FERC order to FERC for further explanation of FERC's decision that a previous transaction with an existing import shipper was not unduly discriminatory. In September 2017, FERC issued its order on remand from the U.S. Court of Appeals for the D.C. Circuit, and reaffirmed its ruling in its prior orders that Cove Point did not violate the prohibition against undue discrimination by agreeing to a capacity reduction and early contract termination with the existing import shipper. In October 2017, the party filed a request for rehearing of the FERC order on remand. This case is pending.

In September 2013, the DOE granted Non-FTA Authorization approval for the export of up to 0.77 bcfe/day of natural gas to countries that do not have an FTA for trade in natural gas. In June 2016, a party filed a petition for review of this approval in the U.S. Court of Appeals for the D.C. Circuit. In November 2017, the U.S. Court of Appeals for the D.C. Circuit issued an order denying the petition for review.

In July 2017, Cove Point submitted an application for a temporary operating permit to the Maryland Department of the Environment, as required prior to the date of first production of LNG for commercial purposes of exporting LNG. The permit was received in December 2017. In February 2018, the Public Service Commission of Maryland issued an order approving Cove Point's August 2017 application to amend the CPCN issued by the Public Service Commission of Maryland in May 2014 to make necessary updates.

FERC

FERC staff in the Office of Enforcement, Division of Investigations, is conducting a non-public investigation of Virginia Power's offers of combustion turbines generators into the PJM day-ahead markets from April 2010 through September 2014. FERC staff notified Virginia Power of its preliminary findings relating to Virginia Power's alleged violation of FERC's rules in connection with these activities. Virginia Power has provided its response to FERC staff's preliminary findings letter explaining why Virginia Power's conduct was lawful and refuting any allegation of wrongdoing. Virginia Power is cooperating fully with the investigation; however, it cannot currently predict whether or to what extent it may incur a material liability.

GREENSVILLE COUNTY

Virginia Power is constructing Greensville County and related transmission interconnection facilities. In August 2016, the Sierra Club filed an administrative appeal in the Circuit Court for the City of Richmond challenging certain provisions in Greensville County's PSD air permit issued by VDEQ in June 2016. In August 2017, the Circuit Court upheld the air permit, and no appeals were filed.

Nuclear Matters

In March 2011, a magnitude 9.0 earthquake and subsequent tsunami caused significant damage at the Fukushima Daiichi nuclear power station in northeast Japan. These events have resulted in significant nuclear safety reviews required by the NRC and industry groups such as the Institute of Nuclear Power Operations. Like other U.S. nuclear operators, Dominion Energy has been gathering supporting data and participating in industry initiatives focused on the ability to respond to and mitigate the consequences of design-basis and beyond-design-basis events at its stations.

In July 2011, an NRC task force provided initial recommendations based on its review of the Fukushima Daiichi accident and in October 2011 the NRC staff prioritized these recommendations into Tiers 1, 2 and 3, with the Tier 1 recommendations consisting of actions which the staff determined should be started without unnecessary delay. In December 2011, the NRC Commissioners approved the agency staff's prioritization and recommendations, and that same month an appropria-

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tions act directed the NRC to require reevaluation of external hazards (not limited to seismic and flooding hazards) as soon as possible.

Based on the prioritized recommendations, in March 2012, the NRC issued orders and information requests requiring specific reviews and actions to all operating reactors, construction permit holders and combined license holders based on the lessons learned from the Fukushima Daiichi event. The orders applicable to Dominion Energy requiring implementation of safety enhancements related to mitigation strategies to respond to extreme natural events resulting in the loss of power at plants, and enhancing spent fuel pool instrumentation have been implemented. The information requests issued by the NRC request each reactor to reevaluate the seismic and external flooding hazards at their site using present-day methods and information, conduct walkdowns of their facilities to ensure protection against the hazards in their current design basis, and to reevaluate their emergency communications systems and staffing levels. The walkdowns of each unit have been completed, audited by the NRC and found to be adequate. Reevaluation of the emergency communications systems and staffing levels was completed as part of the effort to comply with the orders. Reevaluation of the seismic and external flooding hazards is expected to continue through 2018. Dominion Energy and Virginia Power do not currently expect that compliance with the NRC's information requests will materially impact their financial position, results of operations or cash flows during the implementation period. The NRC staff is evaluating the implementation of the longer term Tier 2 and Tier 3 recommendations. Dominion Energy and Virginia Power do not expect material financial impacts related to compliance with Tier 2 and Tier 3 recommendations.

Nuclear Operations

NUCLEAR DECOMMISSIONING—MINIMUM FINANCIAL ASSURANCE

The NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. The 2017 calculation for the NRC minimum financial assurance amount, aggregated for Dominion Energy's and Virginia Power's nuclear units, excluding joint owners' assurance amounts and Millstone Unit 1 and Kewaunee, as those units are in a decommissioning state, was $2.7 billion and $1.8 billion, respectively, and has been satisfied by a combination of the funds being collected and deposited in the nuclear decommissioning trusts and the real annual rate of return growth of the funds allowed by the NRC. The 2017 NRC minimum financial assurance amounts above were calculated using preliminary December 31, 2017 U.S. Bureau of Labor Statistics indices. Dominion Energy believes that the amounts currently available in its decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. Virginia Power also believes that the decommissioning funds and their expected earnings for the Surry and North Anna units will be sufficient to cover decommissioning costs, particularly when combined with future ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. This reflects a positive long-term outlook for trust fund investment returns as the decommissioning of the units will not be complete for decades. Dominion Energy and Virginia Power will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirement, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC. See Note 9 for additional information on nuclear decommissioning trust investments.

NUCLEAR INSURANCE

The Price-Anderson Amendments Act of 1988 provides the public up to $13.44 billion of liability protection per nuclear incident, via obligations required of owners of nuclear power plants, and allows for an inflationary provision adjustment every five years. Dominion Energy and Virginia Power have purchased $450 million of coverage from commercial insurance pools for each reactor site with the remainder provided through a mandatory industry retrospective rating plan. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., the Companies could be assessed up to $127 million for each of their licensed reactors not to exceed $19 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. However, the NRC granted an exemption in March 2015 to remove Kewaunee from the Secondary Financial Protection program. The current levels of nuclear property insurance coverage for Dominion Energy's and Virginia Power's nuclear units are as follows:

(billions)	Coverage
Dominion Energy	
Millstone	**$1.70**
Kewaunee	**1.06**
Virginia Power(1)	
Surry	**$1.70**
North Anna	**1.70**

(1) Surry and North Anna share a blanket property limit of $200 million.

Dominion Energy's and Virginia Power's nuclear property insurance coverage for Millstone, Surry and North Anna exceeds the NRC minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site. Kewaunee meets the NRC minimum requirement of $1.06 billion. This includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first, to return the reactor to and maintain it in a safe and stable condition and second, to decontaminate the reactor and station site in accordance with a plan approved by the NRC. Nuclear property insurance is provided by NEIL, a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. Dominion Energy's and Virginia Power's maximum retrospective premium assessment for the current policy period is $86 million and $50 million, respectively. Based on the severity of the incident, the Board of Directors of the nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. Dominion Energy and Virginia Power have

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the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

Millstone and Virginia Power also purchase accidental outage insurance from NEIL to mitigate certain expenses, including replacement power costs, associated with the prolonged outage of a nuclear unit due to direct physical damage. Under this program, Dominion Energy and Virginia Power are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. Dominion Energy's and Virginia Power's maximum retrospective premium assessment for the current policy period is $22 million and $10 million, respectively.

ODEC, a part owner of North Anna, and Massachusetts Municipal and Green Mountain, part owners of Millstone's Unit 3, are responsible to Dominion Energy and Virginia Power for their share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

SPENT NUCLEAR FUEL

Dominion Energy and Virginia Power entered into contracts with the DOE for the disposal of spent nuclear fuel under provisions of the Nuclear Waste Policy Act of 1982. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by Dominion Energy's and Virginia Power's contracts with the DOE. Dominion Energy and Virginia Power have previously received damages award payments and settlement payments related to these contracts.

By mutual agreement of the parties, the settlement agreements are extendable to provide for resolution of damages incurred after 2013. The settlement agreements for the Surry, North Anna and Millstone plants have been extended to provide for periodic payments for damages incurred through December 31, 2016, and have been extended to provide for periodic payment of damages through December 31, 2019. Pursuit of or possible settlement of the Kewaunee claims for damages incurred after December 31, 2013 is being evaluated.

In 2017, Virginia Power and Dominion Energy received payments of $22 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2015 through December 31, 2015, and $14 million for resolution of claims incurred at Millstone for the period of July 1, 2015 through June 30, 2016.

In 2016, Virginia Power and Dominion Energy received payments of $30 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2014 through December 31, 2014, and $22 million for resolution of claims incurred at Millstone for the period of July 1, 2014 through June 30, 2015.

In 2015, Virginia Power and Dominion Energy received payments of $8 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2013 through December 31, 2013, and $17 million for resolution of claims incurred at Millstone for the period of July 1, 2013 through June 30, 2014.

Dominion Energy and Virginia Power continue to recognize receivables for certain spent nuclear fuel-related costs that they believe are probable of recovery from the DOE. Dominion Energy's receivables for spent nuclear fuel-related costs totaled $46 million and $56 million at December 31, 2017 and 2016, respectively. Virginia Power's receivables for spent nuclear fuel-related costs totaled $30 million and $37 million at December 31, 2017 and 2016, respectively.

Dominion Energy and Virginia Power will continue to manage their spent fuel until it is accepted by the DOE.

Long-Term Purchase Agreements

At December 31, 2017, Virginia Power had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that a third party has used to secure financing for the facility that will provide the contracted goods or services:

(millions)	2018	2019	2020	2021	2022	Thereafter	Total
Purchased electric capacity(1)	**$93**	**$61**	**$52**	**$46**	**$—**	**$—**	**$252**

(1) Commitments represent estimated amounts payable for capacity under a power purchase contract with a qualifying facility and an independent power producer, which ends in 2021. Capacity payments under the contract are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2017, the present value of Virginia Power's total commitment for capacity payments is $221 million. Capacity payments totaled $114 million, $248 million, and $305 million, and energy payments totaled $72 million, $126 million, and $198 million for the years ended 2017, 2016 and 2015, respectively.

Lease Commitments

The Companies lease real estate, vehicles and equipment primarily under operating leases. Payments under certain leases are escalated based on an index such as the consumer price index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2017 are as follows:

(millions)	2018	2019	2020	2021	2022	Thereafter	Total
Dominion Energy(1)	**$68**	**$63**	**$56**	**$48**	**$39**	**$361**	**$635**
Virginia Power	**$34**	**$31**	**$27**	**$22**	**$15**	**$ 28**	**$157**
Dominion Energy Gas	**$15**	**$13**	**$10**	**$ 9**	**$ 7**	**$ 41**	**$ 95**

(1) Amounts include a lease agreement for the Dominion Energy Questar corporate office, which is accounted for as a capital lease. At December 31, 2017 and 2016, the Consolidated Balance Sheets include $27 million and $30 million, respectively, in property, plant and equipment and $33 million and $35 million, respectively, in other deferred credits and other liabilities. The Consolidated Statements of Income include $3 million and less than $1 million recorded in depreciation, depletion and amortization for the years ended December 31, 2017 and 2016.

Rental expense for Dominion Energy totaled $113 million, $104 million, and $99 million for 2017, 2016 and 2015, respectively. Rental expense for Virginia Power totaled $57 million, $52 million, and $51 million for 2017, 2016 and 2015, respectively. Rental expense for Dominion Energy Gas totaled $34 million, $37 million, and $37 million for 2017, 2016 and 2015, respectively. The majority of rental expense is reflected in other operations and maintenance expense in the Consolidated Statements of Income.

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In July 2016, Dominion Energy signed an agreement with a lessor to construct and lease a new corporate office property in Richmond, Virginia. The lessor is providing equity and has obtained financing commitments from debt investors, totaling $365 million, to fund the estimated project costs. The project is expected to be completed by mid-2019. Dominion Energy has been appointed to act as the construction agent for the lessor, during which time Dominion Energy will request cash draws from the lessor and debt investors to fund all project costs, which totaled $139 million as of December 31, 2017. If the project is terminated under certain events of default, Dominion Energy could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion Energy could be required to pay up to 100% of the then funded amount.

The five-year lease term will commence once construction is substantially complete and the facility is able to be occupied. At the end of the initial lease term, Dominion Energy can (i) extend the term of the lease for an additional five years, subject to the approval of the participants, at current market terms, (ii) purchase the property for an amount equal to the project costs or, (iii) subject to certain terms and conditions, sell the property on behalf of the lessor to a third party using commercially reasonable efforts to obtain the highest cash purchase price for the property. If the project is sold and the proceeds from the sale are insufficient to repay the investors for the project costs, Dominion Energy may be required to make a payment to the lessor, up to 87% of project costs, for the difference between the project costs and sale proceeds.

Guarantees, Surety Bonds and Letters of Credit

In October 2017, Dominion Energy entered into a guarantee agreement to support a portion of Atlantic Coast Pipeline's obligation under a $3.4 billion revolving credit facility, also entered in October 2017, with a stated maturity date of October 2021. Dominion Energy's maximum potential loss exposure under the terms of the guarantee is limited to 48% of the outstanding borrowings under the revolving credit facility, an equal percentage to Dominion Energy's ownership in Atlantic Coast Pipeline. As of December 31, 2017, Atlantic Coast Pipeline has borrowed $664 million against the revolving credit facility. Dominion Energy's Consolidated Balance Sheet includes a liability of $28 million associated with this guarantee agreement at December 31, 2017.

In addition, at December 31, 2017, Dominion Energy had issued an additional $48 million of guarantees, primarily to support other equity method investees. No amounts related to the other guarantees have been recorded.

Dominion Energy also enters into guarantee arrangements on behalf of its consolidated subsidiaries, primarily to facilitate their commercial transactions with third parties. If any of these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, Dominion Energy would be obligated to satisfy such obligation. To the extent that a liability subject to a guarantee has been incurred by one of Dominion Energy's consolidated subsidiaries, that liability is included in the Consolidated Financial Statements. Dominion Energy is not required to recognize liabilities for guarantees issued on behalf of its subsidiaries unless it becomes probable that it will have to perform under the guarantees. Terms of the guarantees typically end once obligations have been paid. Dominion Energy currently believes it is unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries' obligations.

At December 31, 2017, Dominion Energy had issued the following subsidiary guarantees:

(millions)	Maximum Exposure
Commodity transactions(1)	**$2,027**
Nuclear obligations(2)	**227**
Cove Point(3)	**1,900**
Solar(4)	**1,064**
Other(5)	**553**
Total(6)	**$5,771**

(1) Guarantees related to commodity commitments of certain subsidiaries. These guarantees were provided to counterparties in order to facilitate physical and financial transaction related commodities and services.

(2) Guarantees related to certain DGI subsidiaries' regarding all aspects of running a nuclear facility.

(3) Guarantees related to Cove Point, in support of terminal services, transportation and construction. Cove Point has two guarantees that have no maximum limit and, therefore, are not included in this amount.

(4) Includes guarantees to facilitate the development of solar projects. Also includes guarantees entered into by DGI on behalf of certain subsidiaries to facilitate the acquisition and development of solar projects.

(5) Guarantees related to other miscellaneous contractual obligations such as leases, environmental obligations, construction projects and insurance programs. Due to the uncertainty of worker's compensation claims, the parental guarantee has no stated limit. Also included are guarantees related to certain DGI subsidiaries' obligations for equity capital contributions and energy generation associated with Fowler Ridge and NedPower. As of December 31, 2017, Dominion Energy's maximum remaining cumulative exposure under these equity funding agreements is $17 million through 2019 and its maximum annual future contributions could range from approximately $4 million to $14 million.

(6) Excludes Dominion Energy's guarantee for the construction of the new corporate office property discussed further within Lease Commitments above.

Additionally, at December 31, 2017, Dominion Energy had purchased $153 million of surety bonds, including $63 million at Virginia Power and $24 million at Dominion Energy Gas, and authorized the issuance of letters of credit by financial institutions of $76 million to facilitate commercial transactions by its subsidiaries with third parties. Under the terms of surety bonds, the Companies are obligated to indemnify the respective surety bond company for any amounts paid.

As of December 31, 2017, Virginia Power had issued $14 million of guarantees primarily to support tax-exempt debt issued through conduits. The related debt matures in 2031 and is included in long-term debt in Virginia Power's Consolidated Balance Sheets. In the event of default by a conduit, Virginia Power would be obligated to repay such amounts, which are limited to the principal and interest then outstanding.

Indemnifications

As part of commercial contract negotiations in the normal course of business, the Companies may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. The Companies are unable to develop an estimate of the maximum potential amount

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of any other future payments under these contracts because events that would obligate them have not yet occurred or, if any such event has occurred, they have not been notified of its occurrence. However, at December 31, 2017, the Companies believe any other future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on their results of operations, cash flows or financial position.

NOTE 23. CREDIT RISK

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, credit policies are maintained, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, counterparties may make available collateral, including letters of credit or cash held as margin deposits, as a result of exceeding agreed-upon credit limits, or may be required to prepay the transaction.

The Companies maintain a provision for credit losses based on factors surrounding the credit risk of their customers, historical trends and other information. Management believes, based on credit policies and the December 31, 2017 provision for credit losses, that it is unlikely that a material adverse effect on financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

General

DOMINION ENERGY

As a diversified energy company, Dominion Energy transacts primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic, Midwest and Rocky Mountain regions of the U.S. Dominion Energy does not believe that this geographic concentration contributes significantly to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion Energy is not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations.

Dominion Energy's exposure to credit risk is concentrated primarily within its energy marketing and price risk management activities, as Dominion Energy transacts with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of any collateral. At December 31, 2017, Dominion Energy's credit exposure totaled $95 million. Of this amount, investment grade counterparties, including those internally rated, represented 26%, and no single counterparty, whether investment grade or non-investment grade, exceeded $13 million of exposure.

VIRGINIA POWER

Virginia Power sells electricity and provides distribution and transmission services to customers in Virginia and northeastern North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of Virginia Power's customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers. Virginia Power's exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Virginia Power's gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2017, Virginia Power's credit exposure totaled $60 million. Of this amount, investment grade counterparties, including those internally rated, represented 9%, and no single counterparty, whether investment grade or non-investment grade, exceeded $13 million of exposure.

DOMINION ENERGY GAS

Dominion Energy Gas transacts mainly with major companies in the energy industry and with residential and commercial energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. Dominion Energy Gas does not believe that this geographic concentration contributes to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion Energy Gas is not exposed to a significant concentration of credit risk for receivables arising from gas utility operations. Dominion Energy Gas' gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2017, Dominion Energy Gas' credit exposure totaled $15 million. Of this amount, investment grade counterparties, including those internally rated, represented 22%, and no single counterparty, whether investment grade or non-investment grade, exceeded $4 million of exposure.

In 2017, DETI provided service to 289 customers with approximately 96% of its storage and transportation revenue being provided through firm services. The ten largest customers provided approximately 38% of the total storage and transportation revenue and the thirty largest provided approximately 68% of the total storage and transportation revenue.

East Ohio distributes natural gas to residential, commercial and industrial customers in Ohio using rates established by the Ohio Commission. Approximately 98% of East Ohio revenues are derived from its regulated gas distribution services. East Ohio's bad debt risk is mitigated by the regulatory framework established by the Ohio Commission. See Note 13 for further information about Ohio's PIPP and UEX Riders that mitigate East Ohio's overall credit risk.

Credit-Related Contingent Provisions

The majority of Dominion Energy's derivative instruments contain credit-related contingent provisions. These provisions require Dominion Energy to provide collateral upon the occurrence of

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specific events, primarily a credit downgrade. If the credit-related contingent features underlying these instruments that are in a liability position and not fully collateralized with cash were fully triggered as of December 31, 2017 and 2016, Dominion Energy would have been required to post an additional $62 million and $3 million, respectively, of collateral to its counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. Dominion Energy had posted no collateral at December 31, 2017 and 2016, related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. The collateral posted includes any amounts paid related to non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of December 31, 2017 and 2016 was $65 million and $9 million, respectively, which does not include the impact of any offsetting asset positions. Credit- related contingent provisions for Virginia Power and Dominion Energy Gas were not material as of December 31, 2017 and 2016. See Note 7 for further information about derivative instruments.

NOTE 24. RELATED-PARTY TRANSACTIONS

Virginia Power and Dominion Energy Gas engage in related party transactions primarily with other Dominion Energy subsidiaries (affiliates). Virginia Power's and Dominion Energy Gas' receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Virginia Power and Dominion Energy Gas are included in Dominion Energy's consolidated federal income tax return and, where applicable, combined income tax returns for Dominion Energy are filed in various states. See Note 2 for further information. Dominion Energy's transactions with equity method investments are described in Note 9. A discussion of significant related party transactions follows.

VIRGINIA POWER

Transactions with Affiliates

Virginia Power transacts with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. Virginia Power also enters into certain commodity derivative contracts with affiliates. Virginia Power uses these contracts, which are principally comprised of commodity swaps, to manage commodity price risks associated with purchases of natural gas. See Notes 7 and 19 for more information. As of December 31, 2017, Virginia Power's derivative assets and liabilities with affiliates were $11 million and $5 million, respectively. As of December 31, 2016, Virginia Power's derivative assets and liabilities with affiliates were $41 million and $8 million, respectively.

Virginia Power participates in certain Dominion Energy benefit plans as described in Note 21. At December 31, 2017 and 2016, Virginia Power's amounts due to Dominion Energy associated with the Dominion Energy Pension Plan and reflected in noncurrent pension and other postretirement benefit liabilities in the Consolidated Balance Sheets were $505 million and $396 million, respectively. At December 31, 2017 and 2016, Virginia Power's amounts due from Dominion Energy associated with the Dominion Energy Retiree Health and Welfare Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $199 million and $130 million, respectively.

DES and other affiliates provide accounting, legal, finance and certain administrative and technical services to Virginia Power. In addition, Virginia Power provides certain services to affiliates, including charges for facilities and equipment usage.

The financial statements for all years presented include costs for certain general, administrative and corporate expenses assigned by DES to Virginia Power on the basis of direct and allocated methods in accordance with Virginia Power's services agreements with DES. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DES resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DES service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable.

Presented below are significant transactions with DES and other affiliates:

Year Ended December 31,	2017	2016	2015
(millions)			
Commodity purchases from affiliates	**$674**	$571	$555
Services provided by affiliates(1)	**453**	454	422
Services provided to affiliates	**25**	22	22

(1) Includes capitalized expenditures of $144 million, $144 million and $143 million for the year ended December 31, 2017, 2016 and 2015, respectively.

Virginia Power has borrowed funds from Dominion Energy under short-term borrowing arrangements. There were $33 million and $262 million in short-term demand note borrowings from Dominion Energy as of December 31, 2017 and 2016, respectively. The weighted-average interest rate of these borrowings was 1.65% and 0.97% at December 31, 2017 and 2016, respectively. Virginia Power had no outstanding borrowings, net of repayments under the Dominion Energy money pool for its nonregulated subsidiaries as of December 31, 2017 and 2016. Interest charges related to Virginia Power's borrowings from Dominion Energy were immaterial for the years ended December 31, 2017, 2016 and 2015.

There were no issuances of Virginia Power's common stock to Dominion Energy in 2017, 2016 or 2015.

DOMINION ENERGY GAS

Transactions with Related Parties

Dominion Energy Gas transacts with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, Dominion Energy Gas provides transportation and storage services to affiliates. Dominion Energy Gas also enters into certain other contracts with affiliates, which are presented separately from contracts involving

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commodities or services. As of December 31, 2017 and 2016, all of Dominion Energy Gas' commodity derivatives were with affiliates. See Notes 7 and 19 for more information. See Note 9 for information regarding transactions with an affiliate.

Dominion Energy Gas participates in certain Dominion Energy benefit plans as described in Note 21. At December 31, 2017 and 2016, Dominion Energy Gas' amounts due from Dominion Energy associated with the Dominion Energy Pension Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $734 million and $697 million, respectively. Dominion Energy Gas' amounts due from Dominion Energy associated with the Dominion Energy Retiree Health and Welfare Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $7 million and $2 million at December 31, 2017 and 2016, respectively.

DES and other affiliates provide accounting, legal, finance and certain administrative and technical services to Dominion Energy Gas. Dominion Energy Gas provides certain services to related parties, including technical services.

The financial statements for all years presented include costs for certain general, administrative and corporate expenses assigned by DES to Dominion Energy Gas on the basis of direct and allocated methods in accordance with Dominion Energy Gas' services agreements with DES. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DES resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DES service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable. The costs of these services follow:

Year Ended December 31,	2017	2016	2015
(millions)			
Purchases of natural gas and transportation and storage services from affiliates	**$ 5**	$ 9	$ 10
Sales of natural gas and transportation and storage services to affiliates	**70**	69	69
Services provided by related parties(1)	**143**	141	133
Services provided to related parties(2)	**156**	128	101

(1) Includes capitalized expenditures of $45 million, $49 million and $57 million for the year ended December 31, 2017, 2016 and 2015, respectively.
(2) Amounts primarily attributable to Atlantic Coast Pipeline.

The following table presents affiliated and related party balances reflected in Dominion Energy Gas' Consolidated Balance Sheets:

At December 31,	2017	2016
(millions)		
Other receivables(1)	**$12**	$10
Customer receivables from related parties	**1**	1
Imbalances receivable from affiliates	**1**	2
Imbalances payable to affiliates(2)	**—**	4
Affiliated notes receivable(3)	**20**	18

(1) Represents amounts due from Atlantic Coast Pipeline, a related party VIE.
(2) Amounts are presented in other current liabilities in Dominion Energy Gas' Consolidated Balance Sheets.
(3) Amounts are presented in other deferred charges and other assets in Dominion Energy Gas' Consolidated Balance Sheets.

Dominion Energy Gas' borrowings under the IRCA with Dominion Energy totaled $18 million and $118 million as of December 31, 2017 and 2016, respectively. The weighted-average interest rate of these borrowings was 1.60% and 1.08% at December 31, 2017 and 2016, respectively. Interest charges related to Dominion Energy Gas' total borrowings from Dominion Energy were immaterial for 2017, 2016 and 2015.

NOTE 25. OPERATING SEGMENTS

The Companies are organized primarily on the basis of products and services sold in the U.S. A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion Energy	Virginia Power	Dominion Energy Gas
Power Delivery	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Power Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Gas Infrastructure	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG terminalling and storage	X		
	Nonregulated retail energy marketing	X		

(1) Includes remaining producer services activities.

In addition to the operating segments above, the Companies also report a Corporate and Other segment.

DOMINION ENERGY

The Corporate and Other Segment of Dominion Energy includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In 2017, Dominion Energy reported an after-tax net benefit of $389 million in the Corporate and Other segment, with $861 million of the net benefit attributable to specific items related to its operating segments.

The net benefit for specific items in 2017 primarily related to the impact of the following items:

- A $979 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act, primarily attributable to:
  - Gas Infrastructure ($324 million);

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- Power Generation ($655 million); partially offset by
- $158 million ($96 million after-tax) of charges associated with equity method investments in wind-powered generation facilities, attributable to Power Generation.

In 2016, Dominion Energy reported after-tax net expenses of $484 million in the Corporate and Other segment, with $180 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2016 primarily related to the impact of the following items:

- A $197 million ($122 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation; and
- A $59 million ($36 million after-tax) charge related to an organizational design initiative, attributable to:
  - Power Delivery ($5 million after-tax);
  - Gas Infrastructure ($12 million after-tax); and
  - Power Generation ($19 million after-tax).

In 2015, Dominion Energy reported after-tax net expenses of $391 million in the Corporate and Other segment, with $136 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2015 primarily related to the impact of the following items:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Power Generation.

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Combined Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to Dominion Energy's operations:

Year Ended December 31, (millions)	Power Delivery	Power Generation	Gas Infrastructure	Corporate and Other	Adjustments & Eliminations	Consolidated Total
2017						
Total revenue from external customers	**$2,206**	**$6,676**	**$2,832**	**$ 16**	**$ 856**	**$12,586**
Intersegment revenue	**22**	**10**	**834**	**610**	**(1,476)**	**—**
Total operating revenue	**2,228**	**6,686**	**3,666**	**626**	**(620)**	**12,586**
Depreciation, depletion and amortization	**593**	**747**	**522**	**43**	**—**	**1,905**
Equity in earnings of equity method investees	**—**	**(181)**	**159**	**4**	**—**	**(18)**
Interest income	**4**	**92**	**45**	**96**	**(155)**	**82**
Interest and related charges	**265**	**342**	**109**	**644**	**(155)**	**1,205**
Income tax expense (benefit)	**334**	**373**	**487**	**(1,224)**	**—**	**(30)**
Net income attributable to Dominion Energy	**531**	**1,181**	**898**	**389**	**—**	**2,999**
Investment in equity method investees	**—**	**81**	**1,422**	**41**	**—**	**1,544**
Capital expenditures	**1,433**	**2,275**	**2,149**	**52**	**—**	**5,909**
Total assets (billions)	**16.7**	**29.0**	**28.0**	**12.0**	**(9.1)**	**76.6**
2016						
Total revenue from external customers	$2,210	$6,747	$2,069	$ (7)	$ 718	$11,737
Intersegment revenue	23	10	697	609	(1,339)	—
Total operating revenue	2,233	6,757	2,766	602	(621)	11,737
Depreciation, depletion and amortization	537	662	330	30	—	1,559
Equity in earnings of equity method investees	—	(16)	105	22	—	111
Interest income	—	74	34	36	(78)	66
Interest and related charges	244	290	38	516	(78)	1,010
Income tax expense (benefit)	308	279	431	(363)	—	655
Net income (loss) attributable to Dominion Energy	484	1,397	726	(484)	—	2,123
Investment in equity method investees	—	228	1,289	44	—	1,561
Capital expenditures	1,320	2,440	2,322	43	—	6,125
Total assets (billions)	15.6	27.1	26.0	10.2	(7.3)	71.6
2015						
Total revenue from external customers	$2,091	$7,001	$1,877	$ (27)	$ 741	$11,683
Intersegment revenue	20	15	695	554	(1,284)	—
Total operating revenue	2,111	7,016	2,572	527	(543)	11,683
Depreciation, depletion and amortization	498	591	262	44	—	1,395
Equity in earnings of equity method investees	—	(15)	60	11	—	56
Interest income	—	64	25	13	(44)	58
Interest and related charges	230	262	27	429	(44)	904
Income tax expense (benefit)	307	465	423	(290)	—	905
Net income (loss) attributable to Dominion Energy	490	1,120	680	(391)	—	1,899
Investment in equity method investees	—	245	1,042	33	—	1,320
Capital expenditures	1,607	2,190	2,153	43	—	5,993

Intersegment sales and transfers for Dominion Energy are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

VIRGINIA POWER

The majority of Virginia Power's revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among Virginia Power's Power Delivery and Power Generation segments.

The Corporate and Other Segment of Virginia Power primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In 2017, Virginia Power reported an after-tax net benefit of $74 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net benefit for specific items in 2017 primarily related to the impact of the following item:

- A $93 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act, attributable to Power Generation.

In 2016, Virginia Power reported after-tax net expenses of $173 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2016 primarily related to the impact of the following item:

- A $197 million ($121 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation.

In 2015, Virginia Power reported after-tax net expenses of $153 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2015 primarily related to the impact of the following items:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Power Generation.

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The following table presents segment information pertaining to Virginia Power's operations:

Year Ended December 31,	Power Delivery	Power Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
(millions)					
2017					
Operating revenue	**$2,212**	**$5,344**	**$ —**	**$ —**	**$7,556**
Depreciation and amortization	**594**	**547**	**—**	**—**	**1,141**
Interest income	**4**	**15**	**3**	**(3)**	**19**
Interest and related charges	**265**	**232**	**—**	**(3)**	**494**
Income tax expense (benefit)	**334**	**534**	**(94)**	**—**	**774**
Net income	**527**	**939**	**74**	**—**	**1,540**
Capital expenditures	**1,439**	**1,290**	**—**	**—**	**2,729**
Total assets (billions)	**16.6**	**18.6**	**—**	**(0.1)**	**35.1**
2016					
Operating revenue	$2,217	$5,390	$ (19)	$ —	$7,588
Depreciation and amortization	537	488	—	—	1,025
Interest income	—	—	—	—	—
Interest and related charges	244	219	—	(2)	461
Income tax expense (benefit)	307	524	(104)	—	727
Net income (loss)	482	909	(173)	—	1,218
Capital expenditures	1,313	1,336	—	—	2,649
Total assets (billions)	15.6	17.8	—	(0.1)	33.3
2015					
Operating revenue	$2,099	$5,566	$ (43)	$ —	$7,622
Depreciation and amortization	498	453	2	—	953
Interest income	—	7	—	—	7
Interest and related charges	230	210	4	(1)	443
Income tax expense (benefit)	308	437	(86)	—	659
Net income (loss)	490	750	(153)	—	1,087
Capital expenditures	1,569	1,120	—	—	2,689

DOMINION ENERGY GAS

The Corporate and Other Segment of Dominion Energy Gas primarily includes specific items attributable to Dominion Energy Gas' operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Energy Gas as a result of Dominion Energy's basis in the net assets contributed.

In 2017, Dominion Energy Gas reported after-tax net expenses of $179 million in its Corporate and Other segment, with $174 million of these net expenses attributable to its operating segment.

The net benefit for specific items in 2017 primarily related to the impact of the following item:

- A $185 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act.

In 2016, Dominion Energy Gas reported after-tax net expenses of $3 million in its Corporate and Other segment, with $7 million of these net expenses attributable to its operating segment.

The net expense for specific items in 2016 primarily related to the impact of the following item:

- An $8 million ($5 million after-tax) charge related to an organizational design initiative.

In 2015, Dominion Energy Gas reported after-tax net expenses of $21 million in its Corporate and Other segment, with $13 million of these net expenses attributable to specific items related to its operating segment.

The net expenses for specific items in 2015 primarily related to the impact of the following item:

- $16 million ($10 million after-tax) ceiling test impairment charge.

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Combined Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to Dominion Energy Gas' operations:

Year Ended December 31,	Gas Infrastructure	Corporate and Other	Consolidated Total
(millions)			
2017			
Operating revenue	**$1,814**	**$ —**	**$1,814**
Depreciation and amortization	**227**	**—**	**227**
Equity in earnings of equity method investees	**21**	**—**	**21**
Interest income	**2**	**—**	**2**
Interest and related charges	**97**	**—**	**97**
Income tax expense (benefit)	**256**	**(205)**	**51**
Net income	**436**	**179**	**615**
Investment in equity method investees	**95**	**—**	**95**
Capital expenditures	**778**	**—**	**778**
Total assets (billions)	**11.3**	**0.6**	**11.9**
2016			
Operating revenue	$1,638	$ —	$1,638
Depreciation and amortization	214	(10)	204
Equity in earnings of equity method investees	21	—	21
Interest income	1	—	1
Interest and related charges	92	2	94
Income tax expense (benefit)	237	(22)	215
Net income (loss)	395	(3)	392
Investment in equity method investees	98	—	98
Capital expenditures	854	—	854
Total assets (billions)	10.5	0.6	11.1
2015			
Operating revenue	$1,716	$ —	$1,716
Depreciation and amortization	213	4	217
Equity in earnings of equity method investees	23	—	23
Interest income	1	—	1
Interest and related charges	72	1	73
Income tax expense (benefit)	296	(13)	283
Net income (loss)	478	(21)	457
Investment in equity method investees	102	—	102
Capital expenditures	795	—	795

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NOTE 26. QUARTERLY FINANCIAL AND COMMON STOCK DATA (UNAUDITED)

A summary of the Companies' quarterly results of operations for the years ended December 31, 2017 and 2016 follows. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

DOMINION ENERGY

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Operating revenue	**$ 3,384**	**$ 2,813**	**$ 3,179**	**$ 3,210**
Income from operations	**1,125**	**801**	**1,200**	**1,004**
Net income including noncontrolling interests	**674**	**417**	**696**	**1,333**
Net income attributable to Dominion Energy	**632**	**390**	**665**	**1,312**
Basic EPS:				
Net income attributable to Dominion Energy	**1.01**	**0.62**	**1.03**	**2.04**
Diluted EPS:				
Net income attributable to Dominion Energy	**1.01**	**0.62**	**1.03**	**2.04**
Dividends declared per share	**0.755**	**0.755**	**0.770**	**0.770**
Common stock prices (intraday high-low)	**$79.36 - 70.87**	**$81.65 - 76.17**	**$80.67 - 75.40**	**$85.30 - 75.75**
2016				
Operating revenue	$ 2,921	$ 2,598	$ 3,132	$ 3,086
Income from operations	882	781	1,145	819
Net income including noncontrolling interests	531	462	728	491
Net income attributable to Dominion Energy	524	452	690	457
Basic EPS:				
Net income attributable to Dominion Energy	0.88	0.73	1.10	0.73
Diluted EPS:				
Net income attributable to Dominion Energy	0.88	0.73	1.10	0.73
Dividends declared per share	0.700	0.700	0.700	0.700
Common stock prices (intraday high-low)	$75.18 - 66.25	$77.93 - 68.71	$78.97 - 72.49	$77.32 - 69.51

Dominion Energy's 2017 results include the impact of the following significant item:

- Fourth quarter results include $851 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act, partially offset by $96 million of after-tax charges associated with our equity method investments in wind-powered generation facilities

Dominion Energy's 2016 results include the impact of the following significant item:

- Fourth quarter results include a $122 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

VIRGINIA POWER

Virginia Power's quarterly results of operations were as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Operating revenue	**$1,831**	**$1,747**	**$2,154**	**$1,824**
Income from operations	**653**	**613**	**847**	**619**
Net income	**356**	**318**	**459**	**407**
2016				
Operating revenue	$1,890	$1,776	$2,211	$1,711
Income from operations	514	553	914	369
Net income	263	280	503	172

Virginia Power's 2017 results include the impact of the following significant item:

- Fourth quarter results include a $93 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act.

Virginia Power's 2016 results include the impact of the following significant item:

- Fourth quarter results include a $121 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

DOMINION ENERGY GAS

Dominion Energy Gas' quarterly results of operations were as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Operating revenue	**$490**	**$422**	**$401**	**$501**
Income from operations	**176**	**137**	**206**	**203**
Net income	**108**	**77**	**117**	**313**
2016				
Operating revenue	$431	$368	$382	$457
Income from operations	175	186	133	175
Net income	98	105	83	106

Dominion Energy Gas's 2017 results include the impact of the following significant item:

- Fourth quarter results include a $197 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act.

There were no significant items impacting Dominion Energy Gas' 2016 quarterly results.

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

DOMINION ENERGY

Senior management, including Dominion Energy's CEO and CFO, evaluated the effectiveness of Dominion Energy's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion Energy's CEO and CFO have concluded that Dominion Energy's disclosure controls and procedures are effective. There were no changes in Dominion Energy's internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Dominion Energy's internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Dominion Energy understands and accepts responsibility for Dominion Energy's consolidated financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion Energy continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as Dominion Energy does throughout all aspects of its business.

Dominion Energy maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Audit Committee of the Board of Directors of Dominion Energy, composed entirely of independent directors, meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss auditing, internal control, and financial reporting matters of Dominion Energy and to ensure that each is properly discharging its responsibilities. Both the independent registered public accounting firm and the internal auditors periodically meet alone with the Audit Committee and have free access to the Audit Committee at any time.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 require Dominion Energy's 2017 Annual Report to contain a management's report and a report of the independent registered public accounting firm regarding the effectiveness of internal control. As a basis for the report, Dominion Energy tested and evaluated the design and operating effectiveness of internal controls. Based on its assessment as of December 31, 2017, Dominion Energy makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion Energy.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Dominion Energy's internal control over financial reporting as of December 31, 2017. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion Energy maintained effective internal control over financial reporting as of December 31, 2017.

Dominion Energy's independent registered public accounting firm is engaged to express an opinion on Dominion Energy's internal control over financial reporting, as stated in their report which is included herein.

February 27, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Dominion Energy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Dominion Energy, Inc. and subsidiaries ("Dominion Energy") at December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, Dominion Energy maintained, in all material respects, effective internal control over financial reporting at December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements at and for the year ended December 31, 2017, of Dominion Energy and our report dated February 27, 2018, expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

Dominion Energy's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Dominion Energy's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to Dominion Energy in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP
Richmond, Virginia
February 27, 2018

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VIRGINIA POWER

Senior management, including Virginia Power's CEO and CFO, evaluated the effectiveness of Virginia Power's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Virginia Power's CEO and CFO have concluded that Virginia Power's disclosure controls and procedures are effective. There were no changes in Virginia Power's internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Virginia Power's internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Virginia Power understands and accepts responsibility for Virginia Power's consolidated financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Virginia Power continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

Virginia Power maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Board of Directors also serves as Virginia Power's Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss Virginia Power's auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Virginia Power's 2017 Annual Report to contain a management's report regarding the effectiveness of internal control. As a basis for the report, Virginia Power tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2017, Virginia Power makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Virginia Power.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Virginia Power's internal control over financial reporting as of December 31, 2017. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Virginia Power maintained effective internal control over financial reporting as of December 31, 2017.

This annual report does not include an attestation report of Virginia Power's independent registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by Virginia Power's independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 27, 2018

DOMINION ENERGY GAS

Senior management, including Dominion Energy Gas' CEO and CFO, evaluated the effectiveness of Dominion Energy Gas' disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion Energy Gas' CEO and CFO have concluded that Dominion Energy Gas' disclosure controls and procedures are effective. There were no changes in Dominion Energy Gas' internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Dominion Energy Gas' internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Dominion Energy Gas understands and accepts responsibility for Dominion Energy Gas' consolidated financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion Energy Gas continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

Dominion Energy Gas maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Board of Directors also serves as Dominion Energy Gas' Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss Dominion Energy Gas' auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Dominion Energy Gas' 2017 Annual Report to contain a management's report regarding the effectiveness of internal control. As a basis for the report, Dominion Energy Gas tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2017, Dominion Energy Gas makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion Energy Gas.

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There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Dominion Energy Gas' internal control over financial reporting as of December 31, 2017. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion Energy Gas maintained effective internal control over financial reporting as of December 31, 2017.

This annual report does not include an attestation report of Dominion Energy Gas' independent registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by Dominion Energy Gas' independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 27, 2018

Item 9B. Other Information

None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

DOMINION ENERGY

The following information for Dominion Energy is incorporated by reference from the Dominion Energy 2018 Proxy Statement, which will be filed on or around March 23, 2018:

- Information regarding the directors required by this item is found under the heading *Election of Directors*.
- Information regarding compliance with Section 16 of the Securities Exchange Act of 1934, as amended, required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance*.
- Information regarding the Dominion Energy Audit Committee Financial expert(s) required by this item is found under the heading *The Committees of the Board—Audit Committee*.
- Information regarding the Dominion Energy Audit Committee required by this item is found under the headings *The Committees of the Board—Audit Committee* and *Audit Committee Report*.
- Information regarding Dominion Energy's Code of Ethics and Business Conduct required by this item is found under the heading *Other Information—Code of Ethics and Business Conduct.*

The information concerning the executive officers of Dominion Energy required by this item is included in Part I of this Form 10-K under the caption *Executive Officers of Dominion Energy*. Each executive officer of Dominion Energy is elected annually.

Item 11. Executive Compensation

DOMINION ENERGY

The following information about Dominion Energy is contained in the 2018 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the headings *Compensation Discussion and Analysis* and *Executive Compensation Tables*; the information regarding Compensation Committee interlocks contained under the heading *Compensation Committee Interlocks and Insider Participation*; the information regarding the Compensation Committee review and discussions of Compensation Discussion and Analysis contained under the heading *Compensation, Governance and Nominating Committee Report*; and the information regarding director compensation contained under the heading *Compensation of Non-Employee Directors.*

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

DOMINION ENERGY

The information concerning stock ownership by directors, executive officers and five percent beneficial owners contained under the heading *Securities Ownership* in the 2018 Proxy Statement is incorporated by reference.

The information regarding equity securities of Dominion Energy that are authorized for issuance under its equity compensation plans contained under the heading *Executive Compensation Tables-Equity Compensation Plans* in the 2018 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

DOMINION ENERGY

The information regarding related party transactions required by this item found under the heading *Other Information–Certain Relationships and Related Party Transactions,* and information regarding director independence found under the heading *Corporate Governance — Director Independence,* in the 2018 Proxy Statement is incorporated by reference.

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Item 14. Principal Accountant Fees and Services

DOMINION ENERGY

The information concerning principal accountant fees and services contained under the heading *Auditor Fees and Pre-Approval Policy* in the 2018 Proxy Statement is incorporated by reference.

VIRGINIA POWER AND DOMINION ENERGY GAS

The following table presents fees paid to Deloitte & Touche LLP for services related to Virginia Power and Dominion Energy Gas for the fiscal years ended December 31, 2017 and 2016.

Type of Fees	2017	2016
(millions)		
Virginia Power		
Audit fees	**$1.93**	$1.82
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total Fees	**$1.93**	$1.82
Dominion Energy Gas		
Audit fees	**$1.09**	$1.05
Audit-related fees	**0.24**	0.16
Tax fees	—	—
All other fees	—	—
Total Fees	**$1.33**	$1.21

Audit fees represent fees of Deloitte & Touche LLP for the audit of Virginia Power and Dominion Energy Gas' annual consolidated financial statements, the review of financial statements included in Virginia Power and Dominion Energy Gas' quarterly Form 10-Q reports, and the services that an independent auditor would customarily provide in connection with subsidiary audits, statutory requirements, regulatory filings, and similar engagements for the fiscal year, such as comfort letters, attest services, consents, and assistance with review of documents filed with the SEC.

Audit-related fees consist of assurance and related services that are reasonably related to the performance of the audit or review of Virginia Power and Dominion Energy Gas' consolidated financial statements or internal control over financial reporting. This category may include fees related to the performance of audits and attest services not required by statute or regulations, due diligence related to mergers, acquisitions, and investments, and accounting consultations about the application of GAAP to proposed transactions.

Virginia Power and Dominion Energy Gas' Boards of Directors have adopted the Dominion Energy Audit Committee pre-approval policy for their independent auditor's services and fees and have delegated the execution of this policy to the Dominion Energy Audit Committee. In accordance with this delegation, each year the Dominion Energy Audit Committee pre-approves a schedule that details the services to be provided for the following year and an estimated charge for such services. At its January 2018 meeting, the Dominion Energy Audit Committee approved Virginia Power and Dominion Energy Gas' schedules of services and fees for 2018. In accordance with the pre-approval policy, any changes to the pre-approved schedule may be pre-approved by the Dominion Energy Audit Committee or a delegated member of the Dominion Energy Audit Committee.

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Part IV
Item 15. Exhibits and Financial Statement Schedules

(a) Certain documents are filed as part of this Form 10-K and are incorporated by reference and found on the pages noted.

1. Financial Statements
   See Index on page 65.

2. All schedules are omitted because they are not applicable, or the required information is either not material or is shown in the financial statements or the related notes.

3. Exhibits (incorporated by reference unless otherwise noted)

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
3.1.a	Dominion Energy, Inc. Articles of Incorporation as amended and restated, effective May 10, 2017 (Exhibit 3.1, Form 8-K filed May 10, 2017, File No.1-8489).	X		
3.1.b	Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on October 30, 2014 (Exhibit 3.1.b, Form 10-Q filed November 3, 2014, File No. 1-2255).		X	
3.1.c	Articles of Organization of Dominion Energy Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.1.d	Articles of Amendment to the Articles of Organization of Dominion Energy Gas Holdings, LLC (Exhibit 3.1, Form 8-K filed May 16, 2017, File No. 1-37591).			X
3.2.a	Dominion Energy, Inc. Amended and Restated Bylaws, effective May 10, 2017 (Exhibit 3.2, Form 8-K filed May 10, 2017, File No. 1-8489).	X		
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255).		X	
3.2.c	Operating Agreement of Dominion Energy Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form 8-K filed May 16, 2017, File No. 001-37591).			X
4	Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of any of their total consolidated assets.	X	X	X
4.1.a	See Exhibit 3.1.a above.	X		
4.1.b	See Exhibit 3.1.b above.		X	
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by Fifty-Eighth Supplemental Indenture (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255); Ninety-Second Supplemental Indenture, dated as of July 1, 2012 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2012 filed August 1, 2012, File No. 1-2255).	X	X	
4.3	Form of Senior Indenture, dated June 1, 1998, between Virginia Electric and Power Company and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(ii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Thirteenth Supplemental Indenture, dated as of January 1, 2006 (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Fourteenth Supplemental Indenture, dated May 1, 2007 (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255); Form of Fifteenth Supplemental Indenture, dated September 1, 2007 (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255); Form of Seventeenth Supplemental Indenture, dated November 1, 2007 (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255); Form of Eighteenth Supplemental Indenture, dated April 1, 2008 (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255); Form of Nineteenth Supplemental and Amending Indenture, dated November 1, 2008 (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255); Form of Twentieth Supplemental Indenture, dated June 1, 2009 (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255); Form of Twenty-First Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 1, 2010, File No. 1-2255);	X	X	

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Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
	Twenty-Second Supplemental Indenture, dated as of January 1, 2012 (Exhibit 4.3, Form 8-K filed January 12, 2012, File No. 1-2255); Twenty-Third Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.3, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fourth Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.4, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fifth Supplemental Indenture, dated as of March 1, 2013 (Exhibit 4.3, Form 8-K filed March 14, 2013, File No. 1-2255); Twenty-Sixth Supplemental Indenture, dated as of August 1, 2013 (Exhibit 4.3, Form 8-K filed August 15, 2013, File No. 1-2255); Twenty-Seventh Supplemental Indenture, dated February 1, 2014 (Exhibit 4.3, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Eighth Supplemental Indenture, dated February 1, 2014 (Exhibit 4.4, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Ninth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.3, Form 8-K filed May 13, 2015, File No. 1-02255); Thirtieth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.4, Form 8-K filed May 13, 2015, File No. 1-02255); Thirty-First Supplemental Indenture, dated January 1, 2016 (Exhibit 4.3, Form 8-K filed January 14, 2016, File No. 000-55337); Thirty-Second Supplemental Indenture, dated November 1, 2016 (Exhibit 4.3, Form 8-K filed November 16, 2016, File No. 000-55337); Thirty-Third Supplemental Indenture, dated November 1, 2016 (Exhibit 4.4, Form 8-K filed November 16, 2016, File No. 000-55337); Thirty-Fourth Supplemental Indenture, dated March 1, 2017 (Exhibit 4.3, Form 8-K filed March 16, 2017; File No. 000-55337).			
4.4	Senior Indenture, dated as of September 1, 2017, between Virginia Electric and Power Company and U.S. Bank National Association, as Trustee (Exhibit 4.1, Form 8-K filed September 13, 2017, File No.000-55337); First Supplemental Indenture, dated as of September 1, 2017 (Exhibit 4.2, Form 8-K filed September 13, 2017, File No.000-55337).	X	X	
4.5	Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) (Exhibit 4.1, Form S-4 Registration Statement filed April 21, 1998, File No. 333-50653), as supplemented by a Form of Second Supplemental Indenture, dated January 1, 2001 (Exhibit 4.6, Form 8-K filed January 12, 2001, File No. 1-8489).	X		
4.6	Indenture, dated April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York Mellon (as successor trustee to United States Trust Company of New York) (Exhibit (4), Certificate of Notification No. 1 filed April 19, 1995, File No. 70-8107); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2, Form 8-A filed October 18, 1996, File No. 1-3196 and relating to the 6 7/8% Debentures Due October 15, 2026); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2, Form 8-A filed December 12, 1997, File No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027).	X		
4.7	Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed December 21, 1999, File No. 333-93187); Form of Sixteenth Supplemental Indenture, dated December 1, 2002 (Exhibit 4.3, Form 8-K filed December 13, 2002, File No. 1-8489); Form of Twenty-First Supplemental Indenture, dated March 1, 2003 (Exhibits 4.3, Form 8-K filed March 4, 2003, File No. 1-8489); Form of Twenty-Second Supplemental Indenture, dated July 1, 2003 (Exhibit 4.2, Form 8-K filed July 22, 2003, File No. 1-8489); Form of Twenty-Ninth Supplemental Indenture, dated June 1, 2005 (Exhibit 4.3, Form 8-K filed June 17, 2005, File No. 1-8489); Form of Thirty-Fifth Supplemental Indenture, dated June 1, 2008 (Exhibit 4.2, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibit 4.3, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Ninth Supplemental Indenture, dated August 1, 2009 (Exhibit 4.3, Form 8-K filed August 12, 2009, File No. 1-8489); Forty-First Supplemental Indenture, dated March 1, 2011 (Exhibit 4.3, Form 8-K, filed March 7, 2011, File No. 1-8489); Forty-Third Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 5, 2011, File No. 1-8489); Forty-Fifth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.3, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Sixth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.4, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Seventh Supplemental Indenture, dated September 1, 2012 (Exhibit 4.5, Form 8-K, filed September 13, 2012, File No. 1-8489);	X		

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Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
	Forty-Eighth Supplemental Indenture, dated March 1, 2014 (Exhibit 4.3, Form 8-K, filed March 24, 2014, File No. 1-8489); Forty-Ninth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.3, Form 8-K, filed November 25, 2014, File No. 1-8489); Fiftieth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.4, Form 8-K, filed November 25, 2014, File No. 1-8489); Fifty-First Supplemental Indenture, dated November 1, 2014 (Exhibit 4.5, Form 8-K, filed November 25, 2014, File No. 1-8489).			
4.8	Indenture, dated as of June 1, 2015, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form 8-K filed June 15, 2015, File No. 1-8489); First Supplemental Indenture, dated as of June 1, 2015 (Exhibit 4.2, Form 8-K filed June 15, 2015, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2015 (Exhibit 4.2, Form 8-K filed September 24, 2015, File No. 1-8489); Third Supplemental Indenture, dated as of February 1, 2016 (Exhibit 4.7, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489); Fourth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.2, Form 8-K filed August 9, 2016, File No. 1-8489); Fifth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.3, Form 8-K filed August 9, 2016, File No. 1-8489); Sixth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.4, Form 8-K filed August 9, 2016, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2016 (Exhibit 4.1, Form 10-Q filed November 9, 2016, File No. 1-8489); Eighth Supplemental Indenture, dated as of December 1, 2016 (Exhibit 4.7, Form 10-K for the fiscal year ended December 31, 2016 filed February 28, 2017, File No. 1-8489); Ninth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.2, Form 8-K filed January 12, 2017, File No. 1-8489); Tenth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.3, Form 8-K filed January 12, 2017, File No. 1-8489); Eleventh Supplemental Indenture, dated as of March 1, 2017 (Exhibit 4.3, Form 10-Q filed May 4, 2017, File No. 1-8489); Twelfth Supplemental Indenture, dated as of June 1, 2017 (Exhibit 4.2, Form 10-Q filed August 3, 2017, File No. 1-8489); Thirteenth Supplemental Indenture, dated December 1, 2017 (filed herewith).	X		
4.9	Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and The Bank of New York Mellon (successor to JPMorgan Chase Bank, N.A.), as Trustee (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); First Supplemental Indenture dated as of June 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489); Third Supplemental and Amending Indenture, dated as of June 1, 2009 (Exhibit 4.2, Form 8-K filed June 15, 2009, File No. 1-8489); Sixth Supplemental Indenture, dated as of June 1, 2014 (Exhibit 4.3, Form 8-K filed July 1, 2014, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2014 (Exhibit 4.3, Form 8-K filed October 3, 2013, File No. 1-8489); Eighth Supplemental Indenture, dated March 7, 2016 (Exhibit 4.4, Form 8-K filed March 7, 2016, File No. 1-8489); Ninth Supplemental Indenture, dated May 26, 2016 (Exhibit 4.4, Form 8-K filed May 26, 2016, File No. 1-8489); Tenth Supplemental Indenture, dated July 1, 2016 (Exhibit 4.3, Form 8-K filed July 19, 2016, File No. 1-8489); Eleventh Supplemental Indenture, dated August 1, 2016 (Exhibit 4.3, Form 8-K filed August 15, 2016, File No. 1-8489); Twelfth Supplemental Indenture, dated August 1, 2016 (Exhibit 4.4, Form 8-K filed August 15, 2016, File No. 1-8489); Thirteenth Supplemental Indenture, dated May 18, 2017 (Exhibit 4.4, Form 8-K filed May 18, 2017, File No. 1-8489).	X		
4.10	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.11	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		

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Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
4.12	2014 Series A Purchase Contract and Pledge Agreement, dated as of July 1, 2014, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.5, Form 8-K filed July 1, 2014, File No. 1-8489).	X		
4.13	2016 Series A Purchase Contract and Pledge Agreement, dated August 15, 2016, between the Company and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed August 15, 2016, File No. 1-8489).	X		
4.14	Indenture, dated as of October 1, 2013, between Dominion Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form S-4 filed April 4, 2014, File No. 333-195066); Second Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.3, Form S-4 filed April 4, 2014, File No. 333-195066); Third Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.4, Form S-4 filed April 4, 2014, File No. 333-195066); Fourth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.2, Form 8-K filed December 8, 2014, File No. 333-195066); Fifth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.3, Form 8-K filed December 8, 2014, File No. 333-195066); Sixth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.4, Form 8-K filed December 8, 2014, File No. 333-195066); Seventh Supplemental Indenture, dated as of November 1, 2015 (Exhibit 4.2, Form 8-K filed November 17, 2015, File No. 001-37591); Eighth Supplemental Indenture, dated as of May 1, 2016 (Exhibit 4.1.a, Form 10-Q filed August 3, 2016, File No. 1-37591); Ninth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.b, Form 10-Q filed August 3, 2016, File No. 1-37591); Tenth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.c, Form 10-Q filed August 3, 2016, File No. 1-37591).	X		X
10.1	$5,000,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Mizuho Bank, Ltd., Bank of America, N.A., Barclays Bank PLC and Wells Fargo Bank, N.A., as Syndication Agents, and other lenders named therein (Exhibit 10.1, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.2	$500,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, KeyBank National Association, as Administrative Agent, U.S. Bank National Association, as Syndication Agent, and other lenders named therein (Exhibit 10.2, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.3	$950 million 364-Day Term Loan Agreement, dated February 9, 2018, by and among Dominion Energy, Inc., The Bank of Nova Scotia, as Administrative Agent, The Bank of Nova Scotia, as Lead Arranger and Bookrunner, and other lenders named therein (Exhibit 10.1, Form 8-K filed February 15, 2018, File No. 1-8489).	X		
10.4	DRS Services Agreement, dated January 1, 2003, between Dominion Resources, Inc. and Dominion Resources Services, Inc. (Exhibit 10.1, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489).	X		
10.5	DRS Services Agreement, dated January 1, 2012, between Dominion Resources Services, Inc. and Virginia Electric and Power Company (Exhibit 10.2, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).		X	
10.6	DRS Services Agreement, dated September 12, 2013, between Dominion Gas Holdings, LLC and Dominion Resources Services, Inc. (Exhibit 10.3, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.7	DRS Services Agreement, dated January 1, 2003, between Dominion Transmission Inc. and Dominion Resources Services, Inc. (Exhibit 10.4, Form S-4 filed April 4, 2014, File No. 333-195066).			X

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Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
10.8	DRS Services Agreement, dated January 1, 2003, between The East Ohio Company and Dominion Resources Services, Inc. (Exhibit 10.5, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.9	DRS Services Agreement, dated January 1, 2003, between Dominion Iroquois, Inc. and Dominion Resources Services, Inc. (Exhibit 10.6, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.10	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255 and File No. 1-8489).	X	X	
10.11	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Virginia Electric and Power Company (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003 filed May 9, 2003, File No. 1-8489 and File No. 1-2255).	X	X	
10.12*	Dominion Energy, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.1, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Energy, Inc. amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003 filed August 11, 2003, File No. 1-8489 and File No. 1-2255), as amended March 31, 2006 (Exhibit 10.1, Form 8-K filed April 4, 2006, File No. 1-8489).	X	X	X
10.14*	Form of Employment Continuity Agreement for certain officers of Dominion Energy, Inc. dated January 24, 2013 (effective for certain officers elected subsequent to February 1, 2013) (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.15*	Dominion Energy, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.2, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.16*	Dominion Energy, Inc. Executives' Deferred Compensation Plan, amended and restated effective December 31, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.17*	Dominion Energy, Inc. New Executive Supplemental Retirement Plan, as amended and restated effective July 1, 2013 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2013 filed August 6, 2013 File No. 1-8489), as amended September 26, 2014 (Exhibit 10.3, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.18*	Dominion Energy, Inc. New Retirement Benefit Restoration Plan, as amended and restated effective January 1, 2009 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-8489 and Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-2255), as amended September 26, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.19*	Dominion Energy, Inc. Stock Accumulation Plan for Outside Directors, amended as of February 27, 2004 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.1, Form 8-K filed December 23, 2004, File No. 1-8489).	X		

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Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
10.20*	Dominion Energy, Inc. Directors Stock Compensation Plan, as amended February 27, 2004 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.2, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.21*	Dominion Energy, Inc. Non-Employee Directors' Compensation Plan, effective January 1, 2005, as amended and restated effective December 17, 2009 (Exhibit 10.18, Form 10-K filed for the fiscal year ended December 31, 2009 filed February 26, 2010, File No. 1-8489).	X		
10.22*	Dominion Energy, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated May 7, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489 and File No. 1-2250).	X	X	X
10.23*	Letter agreement between Dominion Resources, Inc. and Thomas F. Farrell, II, dated February 27, 2003 (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2002 filed March 20, 2003, File No. 1-8489), as amended December 16, 2005 (Exhibit 10.1, Form 8-K filed December 16, 2005, File No. 1-8489).	X	X	X
10.24*	Employment agreement dated February 13, 2007 between Dominion Resources Services, Inc. and Mark F. McGettrick (Exhibit 10.34, Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-8489).	X	X	X
10.25*	Supplemental Retirement Agreement dated October 22, 2003 between Dominion Resources, Inc. and Paul D. Koonce (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-2255).	X	X	X
10.26*	Form of Advancement of Expenses for certain directors and officers of Dominion Energy, Inc., approved October 24, 2008 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-8489 and Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-2255).	X	X	X
10.27*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, originally effective May 1, 2005, as amended and restated effective December 20, 2011 (Exhibit 10.32, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).	X	X	X
10.28*	Supplemental Retirement Agreement with Mark F. McGettrick effective May 19, 2010 (Exhibit 10.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X	X	X
10.29*	Form of Restricted Stock Award Agreement for Mark F. McGettrick and Paul D. Koonce approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.30*	Form of Restricted Stock Award Agreement under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.2, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.31*	Restricted Stock Award Agreement for Thomas F. Farrell, II, dated December 17, 2010 (Exhibit 10.1, Form 8-K filed December 17, 2010, File No. 1-8489).	X	X	X

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Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
10.32*	2014 Performance Grant Plan under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.40, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.33*	Form of Restricted Stock Award Agreement under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.41, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.34*	Dominion Energy, Inc. 2014 Incentive Compensation Plan, effective May 7, 2014 (Exhibit 10.1, Form 8-K filed May 7, 2014, File No. 1-8489).	X	X	X
10.35	Inter-Company Credit Agreement, dated October 17, 2013, between Dominion Resources, Inc. and Dominion Gas Holdings, LLC (Exhibit 10.2, Form S-4 filed April 4, 2014, File No. 333-195066).	X		X
10.36*	2015 Performance Grant Plan under 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.37*	Form of Restricted Stock Award Agreement under the 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.43, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.38*	2016 Performance Grant Plan under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.47, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.39*	Form of Restricted Stock Award Agreement under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.48, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.40*	2017 Performance Grant Plan (Transition Grant) under the 2017 Long-Term Incentive Program approved January 24, 2017 (Exhibit 10.45, Form 10-K for the fiscal year ended December 31, 2016 filed February 28, 2017, File No. 1-8489).	X	X	X
10.41*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Program approved January 24, 2017 (Exhibit 10.46, Form 10-K for the fiscal year ended December 31, 2016 filed February 28, 2017, File No. 1-8489).	X	X	X
10.42*	2017 Performance Grant Plan under the 2017 Long-Term Incentive Program approved January 24, 2017 (Exhibit 10.3, Form 10-Q for the quarter ended March 31, 2017 filed May 4, 2017, File No. 1-8489).	X	X	X
10.43*	2018 Performance Grant Plan under the 2018 Long-Term Incentive Program approved January 25, 2018 (filed herewith).	X	X	X
10.44*	Form of Restricted Stock Award Agreement under the 2018 Long-Term Incentive Program approved January 25, 2018 (filed herewith).	X	X	X
10.45*	Base salaries for named executive officers of Dominion Energy, Inc. (filed herewith).	X		
10.46*	Non-employee directors' annual compensation for Dominion Energy, Inc. (filed herewith).	X		
12.1	Ratio of earnings to fixed charges for Dominion Energy, Inc. (filed herewith).	X		
12.2	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.3	Ratio of earnings to fixed charges for Dominion Energy Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Energy, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X

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Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
31.a	Certification by Chief Executive Officer of Dominion Energy, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Energy, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.e	Certification by Chief Executive Officer of Dominion Energy Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
31.f	Certification by Chief Financial Officer of Dominion Energy Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Energy, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).	X		
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).		X	
32.c	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Energy Gas Holdings, LLC as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).			X
101	The following financial statements from Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2017, filed on February 27, 2018, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Common Shareholders' Equity (iv) Consolidated Statements of Comprehensive Income (v) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements.	X	X	X

* *Indicates management contract or compensatory plan or arrangement.*

Item 16. Form 10-K Summary

None.

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Signatures

DOMINION ENERGY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DOMINION ENERGY, INC.

By: /s/ Thomas F. Farrell, II
(Thomas F. Farrell, II, Chairman, President and Chief Executive Officer)

Date: February 27, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 27th day of February, 2018.

Signature	Title
/s/ Thomas F. Farrell, II **Thomas F. Farrell, II**	Chairman of the Board of Directors, President and Chief Executive Officer
/s/ William P. Barr **William P. Barr**	Director
/s/ Helen E. Dragas **Helen E. Dragas**	Director
/s/ James O. Ellis, Jr. **James O. Ellis, Jr.**	Director
/s/ John W. Harris **John W. Harris**	Director
/s/ Ronald W. Jibson **Ronald W. Jibson**	Director
/s/ Mark J. Kington **Mark J. Kington**	Director
/s/ Joseph M. Rigby **Joseph M. Rigby**	Director
/s/ Pamela J. Royal **Pamela J. Royal**	Director
/s/ Robert H. Spilman, Jr. **Robert H. Spilman, Jr.**	Director
/s/ Susan N. Story **Susan N. Story**	Director
/s/ Michael E. Szymanczyk **Michael E. Szymanczyk**	Director
/s/ Mark F. McGettrick **Mark F. McGettrick**	Executive Vice President and Chief Financial Officer
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

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Virginia Power

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ Thomas F. Farrell, II
(Thomas F. Farrell, II, Chairman of the Board of Directors and Chief Executive Officer)

Date: February 27, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 27th day of February, 2018.

Signature	Title
/s/ Thomas F. Farrell, II **Thomas F. Farrell, II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

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Dominion Energy Gas

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DOMINION ENERGY GAS HOLDINGS, LLC

By: /s/ Thomas F. Farrell, II
(Thomas F. Farrell, II, Chairman of the Board of Directors and Chief Executive Officer)

Date: February 27, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 27th day of February, 2018.

Signature	Title
/s/ Thomas F. Farrell, II **Thomas F. Farrell, II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

Exhibit 4.8

DOMINION ENERGY, INC.
Issuer

AND

DEUTSCHE BANK TRUST COMPANY AMERICAS
Trustee

Thirteenth Supplemental Indenture

Dated as of December 1, 2017

$300,000,000

2017 Series E Floating Rate Senior Notes

due 2020

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1 This Table of Contents does not constitute part of the Indenture or have any bearing upon the interpretation of any of its terms and provisions.

THIS THIRTEENTH SUPPLEMENTAL INDENTURE is made as of the 1st day of December, 2017, by and between DOMINION ENERGY, INC. (formerly Dominion Resources, Inc.), a Virginia corporation, having its principal office at 120 Tredegar Street, Richmond, Virginia 23219 (the “Company” or “Issuer”), and DEUTSCHE BANK TRUST COMPANY AMERICAS, a New York banking corporation, as Trustee, having a corporate trust office at 60 Wall Street, 16th Floor, New York, New York 10005 (herein called the “Trustee”).

W I T N E S S E T H:

WHEREAS, the Company has heretofore entered into an Indenture dated as of June 1, 2015, between the Company and the Trustee (as amended, restated or otherwise modified, the “Base Indenture”) with respect to senior debt securities;

WHEREAS, the Base Indenture is incorporated herein by this reference and the Base Indenture, as heretofore supplemented, as further supplemented by this Thirteenth Supplemental Indenture, and as may be hereafter supplemented or amended from time to time, is herein called the “Indenture”;

WHEREAS, under the Base Indenture, a new series of Securities may at any time be established in accordance with the provisions of the Base Indenture and the terms of such series may be described by a supplemental indenture executed by the Company and the Trustee;

WHEREAS, the Company proposes to create under the Indenture a new series of Securities;

WHEREAS, additional Securities of other series hereafter established, except as may be limited in the Base Indenture as at the time supplemented and modified, may be issued from time to time pursuant to the Indenture as at the time supplemented and modified; and

WHEREAS, all conditions necessary to authorize the execution and delivery of this Thirteenth Supplemental Indenture and to make it a valid and binding obligation of the Company have been done or performed.

NOW, THEREFORE, in consideration of the agreements and obligations set forth herein and for other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto hereby agree as follows:

ARTICLE I
2017 SERIES E FLOATING RATE SENIOR NOTES DUE 2020

SECTION 101 Establishment. There is hereby established a new series of Securities to be issued under the Indenture, to be designated as the Company’s 2017 Series E Floating Rate Senior Notes due 2020 (the “Series E Senior Notes”).

There are to be authenticated and delivered $300,000,000 principal amount of Series E Senior Notes, and such principal amount of the Series E Senior Notes may be increased from time to time pursuant to the penultimate paragraph of Section 301 of the Base Indenture. All Series E Senior Notes need not be issued at the same time and such series may be reopened at any time, without the consent of any Holder, for issuances of additional Series E Senior Notes. Any such additional Series E Senior Notes will have the same interest rate, maturity and other terms as those initially issued, and shall be consolidated with and part of the same series of Series E Senior notes initially issued under this Thirteenth Supplemental Indenture. Further Series E Senior Notes may also be authenticated and delivered as provided by Sections 304, 305, 306, 905 or 1107 of the Base Indenture.

The Series E Senior Notes shall be issued as Registered Securities in global form without coupons, in substantially the form set out in Exhibit A hereto. The entire initially issued principal amount of the Series E Senior Notes shall initially be evidenced by one or more certificates issued to Cede & Co., as nominee for The Depository Trust Company.

The form of the Trustee's Certificate of Authentication for the Series E Senior Notes shall be in substantially the form set forth in Exhibit A hereto.

Each Series E Senior Note shall be dated the date of authentication thereof and shall bear interest from the date of original issuance thereof or from the most recent Interest Payment Date to which interest has been paid or duly provided for.

SECTION 102 Definitions. The following defined terms used herein shall, unless the context otherwise requires, have the meanings specified below. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Base Indenture. Unless the context otherwise requires, any references to a "Section" refers to a Section of this Thirteenth Supplemental Indenture.

"Business Day" means a day other than (i) a Saturday or a Sunday, (ii) a day on which banks in New York, New York are authorized or obligated by law or executive order to remain closed or (iii) a day on which the Corporate Trust Office is closed for business.

"Calculation Agent" means Deutsche Bank Trust Company Americas, a New York banking corporation, or its successor appointed by the Company, acting as calculation agent.

"Depositary" has the meaning set forth in Section 105.

"Distribution Compliance Period" has the meaning set forth in Section 204.

"Interest Payment Dates" means March 1, June 1, September 1 and December 1 of each year, commencing on March 1, 2018.

"LIBOR Business Day" means any Business Day on which dealings in deposits in U.S. Dollars are transacted in the London Inter-Bank Market.

"LIBOR Interest Determination Date" means the second LIBOR Business Day preceding each LIBOR Rate Reset Date.

"LIBOR Rate Reset Date" means, subject to Section 103, the 1st day of the months of March, June, September and December of each year commencing on March 1, 2018.

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"Original Issue Date" means December 8, 2017.

"Outstanding," when used with respect to the Series E Senior Notes, means, as of the date of determination, all Series E Senior Notes theretofore authenticated and delivered under the Indenture, except:

(i) Series E Senior Notes theretofore canceled by the Trustee or delivered to the Trustee for cancellation;

(ii) Series E Senior Notes for whose payment at the Maturity thereof money in the necessary amount has been theretofore deposited (other than pursuant to Section 402 of the Base Indenture) with the Trustee or any Paying Agent (other than the Company) in trust or set aside and segregated in trust by the Company (if the Company shall act as its own Paying Agent) for the Holders of such Series E Senior Notes;

(iii) Series E Senior Notes with respect to which the Company has effected defeasance or covenant defeasance pursuant to Section 402 of the Base Indenture, except to the extent provided in Section 402 of the Base Indenture; and

(iv) Series E Senior Notes that have been paid pursuant to Section 306 of the Base Indenture or in exchange for or in lieu of which other Series E Senior Notes have been authenticated and delivered pursuant to the Indenture, other than any such Series E Senior Notes in respect of which there shall have been presented to the Trustee proof satisfactory to it that such Series E Senior Notes are held by a bona fide purchaser in whose hands such Series E Senior Notes are valid obligations of the Company; provided, however, that in determining whether the Holders of the requisite principal amount of Outstanding Series E Senior Notes have given any request, demand, authorization, direction, notice, consent or waiver under the Indenture or are present at a meeting of Holders of Series E Senior Notes for quorum purposes, Series E Senior Notes owned by the Company or any other obligor upon the Series E Senior Notes or any Affiliate of the Company or such other obligor shall be disregarded and deemed not to be Outstanding, except that, in determining whether the Trustee shall be protected in making any such determination or relying upon any such request, demand, authorization, direction, notice, consent or waiver, only Series E Senior Notes which a Responsible Officer of the Trustee actually knows to be so owned shall be so disregarded. Series E Senior Notes so owned which shall have been pledged in good faith may be regarded as Outstanding if the pledgee establishes to the satisfaction of the Trustee (a) the pledgee's right so to act with respect to such Series E Senior Notes and (b) that the pledgee is not the Company or any other obligor upon the Series E Senior Notes or an Affiliate of the Company or such other obligor.

"QIB" means a "qualified institutional buyer" as defined in Rule 144A.

"Regular Record Date" means, with respect to each Interest Payment Date, the close of business on the Business Day preceding such Interest Payment Date; provided, that with respect to Series E Senior Notes that are not represented by one or more Global Securities, the Regular Record Date shall be the close of business on the fifteenth (15th) calendar day (whether or not a Business Day) preceding such Interest Payment Date.

"Regulation S" means Regulation S promulgated under the Securities Act.

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“Regulation S Global Security” has the meaning set forth in Section 105.

“Restricted Legend” has the meaning set forth in Section 202.

“Restricted Security” has the meaning set forth in Section 202.

“Reuters Page LIBOR01” means the display so designated on the Reuters 3000 Xtra (or such other page as may replace that page on that service, or such other service as may be nominated by the Company, for the purpose of displaying rates or prices comparable to the London Inter-Bank Offered Rate for U.S. Dollar deposits).

“Rule 144A” means Rule 144A promulgated under the Securities Act.

“Rule 144A Global Security” has the meaning set forth in Section 105.

“Securities Act” means the Securities Act of 1933, as amended.

“Series E Senior Notes” has the meaning set forth in Section 101.

“Stated Maturity” means December 1, 2020.

“Three Month LIBOR Rate” means the rate determined in accordance with the following provisions:

(i) On the LIBOR Interest Determination Date, the Calculation Agent or its affiliate will determine the Three Month LIBOR Rate which shall be the rate for deposits in U.S. Dollars having a three-month maturity which appears on Reuters Page LIBOR01 as of 11:00 a.m., London time, on the LIBOR Interest Determination Date.

(ii) If no rate appears on Reuters Page LIBOR01 on the LIBOR Interest Determination Date, the Calculation Agent will request the principal London offices of each of four major reference banks (which may include affiliates of the underwriters) in the London Inter-Bank Market selected by the Calculation Agent (after consultation with the Company) to provide the Calculation Agent with their offered quotations for deposits in U.S. Dollars for the period of three months, commencing on the applicable LIBOR Rate Reset Date, to prime banks in the London Inter-Bank Market at approximately 11:00 a.m., London time, on that LIBOR Interest Determination Date and in a principal amount that is representative for a single transaction in U.S. Dollars in that market at that time.

If at least two quotations are provided, then the Three Month LIBOR Rate will be the average (rounded, if necessary, to the nearest one hundredth (0.01) of a percent) of those quotations. If fewer than two quotations are provided, then the Three Month LIBOR Rate will be the average (rounded, if necessary, to the nearest one hundredth (0.01) of a percent) of the rates quoted at approximately 11:00 a.m., New York City time, on the LIBOR Interest Determination Date by three major banks (which may include affiliates of the underwriters) in New York City selected by the Calculation Agent (after consultation with the Company) for loans in U.S. Dollars to leading European banks, having a three-month maturity and in a principal amount that is representative for a single transaction in U.S. Dollars in that market at
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that time. If the banks selected by the Calculation Agent are not providing quotations in the manner described by this paragraph, the rate for the period following the LIBOR Interest Determination Date will be the rate in effect on that LIBOR Interest Determination Date.

The terms “Company,” “Issuer,” “Trustee,” “Base Indenture,” and “Indenture” shall have the respective meanings set forth in the recitals to this Thirteenth Supplemental Indenture and the paragraph preceding such recitals.

SECTION 103 Payment of Principal and Interest. The principal of the Series E Senior Notes shall be due at the Stated Maturity. The unpaid principal amount of the Series E Senior Notes shall bear interest at a floating rate per annum determined by the Calculation Agent as described below, until paid or duly provided for, such interest to accrue from the Original Issue Date or from the most recent Interest Payment Date to which interest has been paid or duly provided for. Interest shall be paid quarterly in arrears on each Interest Payment Date to the Person in whose name the Series E Senior Notes are registered on the Regular Record Date for such Interest Payment Date; provided that interest payable at the Stated Maturity of principal will be paid to the Person to whom principal is payable. Any such interest that is not so punctually paid or duly provided for will forthwith cease to be payable to the Holders on such Regular Record Date and may either be paid to the Person or Persons in whose name the Series E Senior Notes are registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee (in accordance with Section 307 of the Base Indenture), notice whereof shall be given to Holders of the Series E Senior Notes not less than ten (10) days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on which the Series E Senior Notes may be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Base Indenture.

The per annum interest rate on the Series E Senior Notes will be equal to the Three Month LIBOR Rate plus 40 basis points (0.40%); provided that the per annum interest rate for the period from the Original Issue Date to the first LIBOR Rate Reset Date will be 1.52263% per annum (the “Initial Interest Rate”). The per annum interest rate shall be reset on each LIBOR Rate Reset Date.

If any LIBOR Rate Reset Date falls on a day that is not a Business Day, the LIBOR Rate Reset Date will be postponed to the next day that is a Business Day, except that if that Business Day is in the next succeeding calendar month, the LIBOR Rate Reset Date will be the next preceding Business Day. The interest rate in effect on any LIBOR Rate Reset Date will be the applicable rate as reset on that date. The interest rate applicable to any other day will either be the Initial Interest Rate or the interest rate as reset on the immediately preceding LIBOR Rate Reset Date.

Payments of interest on the Series E Senior Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series E Senior Notes shall be computed and paid on the basis the actual number of days in the relevant quarterly period (including the first day of the quarterly period and excluding the last day of the quarterly period) divided by 360. If any Interest Payment Date, other than the Stated Maturity, falls on a day that is not a Business Day, the Interest Payment Date will be postponed to the next day that

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is a Business Day, except that if that Business Day is in the next succeeding calendar month, the Interest Payment Date will be the immediately preceding Business Day. If the Stated Maturity falls on a day that is not a Business Day, the payment of interest and principal will be made on the next succeeding Business Day, and no interest on such payment will accrue for the period from and after the Stated Maturity.

Accrued interest on any Series E Senior Note will be calculated by multiplying the principal amount of the Series E Senior Note by an accrued interest factor. The accrued interest factor will be computed by adding the interest factors calculated for each day in the period for which interest is being paid. The interest factor for each day is computed by dividing the interest rate applicable to that day by 360.

Payment of the principal and interest on the Series E Senior Notes shall be made at the office of the Paying Agent in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts, with any such payment that is due at the Stated Maturity of any Series E Senior Notes, or upon repurchase being made upon surrender of such Series E Senior Notes to the Paying Agent. Payments of interest (including interest on any Interest Payment Date) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least sixteen (16) days prior to the date for payment by the Person entitled thereto.

SECTION 104 Denominations. The Series E Senior Notes may be issued in denominations of $2,000, or any greater integral multiple of $1,000.

SECTION 105 Global Securities. The Series E Senior Notes offered and sold to QIBs in reliance on Rule 144A will be initially issued in the form of one or more Global Securities (the “Rule 144A Global Security”), and the Series E Senior Notes offered and sold in offshore transactions to non-U.S. persons in reliance on Regulation S will be initially issued in the form of one or more Global Securities (the “Regulation S Global Security”), in each case registered in the name of the Depositary (which shall be The Depository Trust Company) or its nominee. Except under the limited circumstances described below, Series E Senior Notes represented by such Global Securities will not be exchangeable for, and will not otherwise be issuable as, Series E Senior Notes in definitive form registered in names other than the Depositary or its nominee. The Global Securities described above may not be transferred except by the Depositary to a nominee of the Depositary or by a nominee of the Depositary to the Depositary or another nominee of the Depositary or to a successor Depositary or its nominee.

Owners of beneficial interests in such a Global Security will not be considered the Holders thereof for any purpose under the Indenture, and no Global Security representing a Series E Senior Note shall be exchangeable, except for another Global Security of like denomination and tenor to be registered in the name of the Depositary or its nominee or to a successor Depositary or its nominee or except as described below. The rights of Holders of such Global Security shall be exercised only through the Depositary.

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A Global Security shall be exchangeable for Series E Senior Notes registered in the names of persons other than the Depositary or its nominee only if (i) the Depositary notifies the Company that it is unwilling or unable to continue as a Depositary for such Global Security and no successor Depositary shall have been appointed by the Company within ninety (90) days of receipt by the Company of such notification, or if at any time the Depositary ceases to be a clearing agency registered under the Exchange Act at a time when the Depositary is required to be so registered to act as such Depositary and no successor Depositary shall have been appointed by the Company within ninety (90) days after it becomes aware of such cessation, (ii) the Company in its sole discretion, and subject to the procedures of the Depositary, determines that such Global Security shall be so exchangeable, in which case Series E Senior Notes in definitive form will be printed and delivered to the Depositary, or (iii) an Event of Default has occurred and is continuing with respect to the Series E Senior Notes. Any Global Security that is exchangeable pursuant to the preceding sentence shall be exchangeable for Series E Senior Notes registered in such names as the Depositary shall direct.

SECTION 106 Redemption. The Series E Senior Notes shall not be redeemable at any time prior to the Stated Maturity.

SECTION 107 Sinking Fund; Conversion. The Series E Senior Notes shall not have a sinking fund. The Series E Senior Notes are not convertible into or exchangeable for Equity Securities or any other securities.

SECTION 108 Additional Interest on Overdue Amounts. Any principal of and installment of interest on the Series E Senior Notes that is overdue shall bear interest at the then applicable interest rate (to the extent that the payment of such interest shall be legally enforceable), from the dates such amounts are due until they are paid or made available for payment, and such interest shall be payable on demand.

SECTION 109 Paying Agent; Security Registrar. The Trustee shall initially serve as Paying Agent and Security Registrar with respect to the Series E Senior Notes, with the Place of Payment initially being the Corporate Trust Office. The Company may change the Paying Agent or Security Registrar without prior notice to Holders of the Series E Senior Notes, and the Company or any of its subsidiaries may act as Paying Agent or Security Registrar.

ARTICLE II
TRANSFER AND EXCHANGE

SECTION 201 Transfer and Exchange of Global Securities. The transfer and exchange of beneficial interests in the Global Securities shall be effected through the Depositary, in accordance with this Thirteenth Supplemental Indenture (including applicable restrictions on transfer set forth herein, if any) and the procedures of the Depositary therefor.

SECTION 202 Restricted Legend. Except as otherwise provided in Section 203 and as indicated on Exhibit A, each Series E Senior Note (each a "Restricted Security") shall bear the following legend (the "Restricted Legend") on the face thereof:

THIS SERIES E SENIOR NOTE (OR ITS PREDECESSOR) WAS ORIGINALLY ISSUED IN A TRANSACTION EXEMPT FROM REGISTRATION UNDER THE UNITED

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STATES SECURITIES ACT OF 1933, AS AMENDED (THE “SECURITIES ACT”), AND THIS SERIES E SENIOR NOTE MAY NOT BE OFFERED, SOLD OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION OR AN APPLICABLE EXEMPTION THEREFROM. EACH PURCHASER OF THIS SERIES E SENIOR NOTE IS HEREBY NOTIFIED THAT THE SELLER OF THIS SERIES E SENIOR NOTE MAY BE RELYING ON THE EXEMPTION FROM THE PROVISIONS OF SECTION 5 OF THE SECURITIES ACT PROVIDED BY RULE 144A THEREUNDER.

THE HOLDER OF THIS SERIES E SENIOR NOTE AGREES FOR THE BENEFIT OF THE COMPANY THAT (A) THIS SERIES E SENIOR NOTE MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED, ONLY (I) IN THE UNITED STATES TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (II) OUTSIDE THE UNITED STATES IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 904 UNDER THE SECURITIES ACT, (III) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE), (IV) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, OR (V) TO AN INSTITUTIONAL “ACCREDITED INVESTOR” (AS DEFINED IN RULE 501(A)(1), (2), (3) OR (7) OF REGULATION D UNDER THE SECURITIES ACT) THAT IS ACQUIRING THE NOTE FOR ITS OWN ACCOUNT, OR FOR THE ACCOUNT OF SUCH AN INSTITUTIONAL “ACCREDITED INVESTOR” FOR INVESTMENT PURPOSES AND NOT WITH A VIEW TO, OR FOR OFFER OR SALE IN CONNECTION WITH, ANY DISTRIBUTION IN VIOLATION OF THE SECURITIES ACT, IN EACH OF CASES (I) THROUGH (V) IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES, AND (B) THE HOLDER WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS SERIES E SENIOR NOTE FROM IT OF THE RESALE RESTRICTIONS REFERRED TO IN CLAUSE (A) ABOVE.

THE HOLDER AGREES THAT IT WILL DELIVER TO EACH PERSON TO WHOM THIS SERIES E SENIOR NOTE OR AN INTEREST HEREIN IS TRANSFERRED A NOTICE SUBSTANTIALLY TO THE EFFECT OF THIS LEGEND.

THE HOLDER AGREES THAT, BEFORE THE HOLDER OFFERS, SELLS OR OTHERWISE TRANSFERS THIS SERIES E SENIOR NOTE, THE COMPANY MAY REQUIRE THE HOLDER OF THIS SERIES E SENIOR NOTE TO DELIVER A WRITTEN OPINION, CERTIFICATIONS AND/OR OTHER INFORMATION THAT IT REASONABLY REQUIRES TO CONFIRM THAT SUCH PROPOSED TRANSFER IS BEING MADE PURSUANT TO AN EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE UNITED STATES.

AS USED IN THIS SERIES E SENIOR NOTE, THE TERMS “OFFSHORE TRANSACTION,” “U.S. PERSON” AND “UNITED STATES” HAVE THE MEANINGS GIVEN TO THEM BY RULE 902 OF REGULATION S UNDER THE SECURITIES ACT.

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SECTION 203 Removal of Restricted Legend. The Company may instruct the Trustee in writing to cancel any Series E Senior Note and, upon receipt of a Company Order, authenticate a replacement Series E Senior Note, registered in the name of the Holder thereof (or its transferee), that does not bear the Restricted Legend, and the Trustee will comply with such instruction, if the Company determines (upon the advice of counsel and such other certifications and evidence as the Company may reasonably require) that a Series E Senior Note is eligible for resale pursuant to Rule 144 under the Securities Act (or a successor provision) and that the Restricted Legend is no longer necessary or appropriate in order to ensure that subsequent transfers of such Series E Senior Note (or a beneficial interest therein) are effected in compliance with the Securities Act; provided, however, that in such circumstances, the Trustee shall require an Opinion of Counsel and an Officers' Certificate prior to authenticating any such replacement Series E Senior Note.

SECTION 204 Registration of Transfer or Exchange. The registration of transfer or exchange of any Series E Senior Note (or a beneficial interest therein) that bears the Restricted Legend may only be made in compliance with the provisions of the Restricted Legend and as set forth below.

(i) Prior to and including the fortieth (40th) day after the later of the commencement of the offering of the Series E Senior Notes and the Original Issue Date (such period through and including such fortieth (40th) day, the "Distribution Compliance Period"), transfers by an owner of a beneficial interest in a Regulation S Global Security to a transferee who takes delivery of such interest through a Rule 144A Global Security of that series will be made only upon receipt by the Trustee of a written certification from the transferor of the beneficial interest to the effect that such transfer is being made to a Person whom the transferor reasonably believes is purchasing for its own account or accounts as to which it exercises sole investment discretion and is a QIB in a transaction meeting the requirements of Rule 144A and the requirements of applicable securities laws of any state of the United States or any other jurisdiction.

(ii) Transfers by an owner of a beneficial interest in the Rule 144A Global Security to a transferee who takes delivery through the Regulation S Global Security of that series, whether before or after the expiration of the Distribution Compliance Period, will be made only upon receipt by the Trustee of a certification from the transferor to the effect that such transfer is being made in accordance with Rule 904 of Regulation S or Rule 144 under the Securities Act and that, if such transfer is being made prior to the expiration of the Distribution Compliance Period, the interest transferred will be held immediately thereafter through Euroclear Bank SA/NV, as operator of the Euroclear System or Clearstream Banking, société anonyme, Luxembourg.

(iii) Any beneficial interest in one of the Global Securities that is transferred to a Person who takes delivery in the form of an interest in another Global Security of that series will, upon transfer, cease to be an interest in the initial Global Security of that series and will become an interest in the other Global Security of that series and, accordingly, will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to beneficial interests in such other Global Security of that series for as long as it remains such an interest.

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SECTION 205 Preservation of Information. The Trustee will retain copies of all certificates, opinions and other documents received in connection with the registration of transfer or exchange of a Series E Senior Note (or a beneficial interest therein) in accordance with its customary policy, and the Company will have the right to request copies thereof at any reasonable time upon written notice to the Trustee.

SECTION 206 Acknowledgment of Restrictions; Indemnification; No Obligation of Trustee. By its acceptance of any Series E Senior Note bearing the Restricted Legend, each Holder of such a Series E Senior Note acknowledges the restrictions on registrations of transfer or exchange of such Series E Senior Note set forth in this Thirteenth Supplemental Indenture and in the Restricted Legend and agrees that it will register the transfer or exchange of such Series E Senior Note only as provided in this Thirteenth Supplemental Indenture. The Security Registrar shall not register a transfer or exchange of any Series E Senior Note unless such transfer or exchange complies with the restrictions on transfer or exchange of such Series E Senior Note set forth in this Thirteenth Supplemental Indenture. In connection with any registration of transfer or exchange of Series E Senior Notes, each Holder agrees by its acceptance of the Series E Senior Notes to furnish the Security Registrar or the Company such certifications, legal opinions or other information as either of them may reasonably require to confirm that such registration of transfer or exchange is being made pursuant to an exemption from, or a transaction not subject to, the registration requirements of the Securities Act; provided that the Security Registrar shall not be required to determine (but may rely on a determination made by the Company with respect to) the sufficiency of any such certifications, legal opinions or other information.

The Security Registrar shall retain copies of all letters, notices and other written communications received pursuant to the Indenture in accordance with its customary policy. The Company shall have the right to request copies of all such letters, notices or other written communications at any reasonable time upon the giving of written notice to the Security Registrar.

Each Holder of a Series E Senior Note agrees to indemnify the Company, the Security Registrar and the Trustee against any liability that may result from the transfer, exchange or assignment of such Holder's Series E Senior Note in violation of any provision of this Thirteenth Supplemental Indenture and/or applicable United States Federal or state securities law.

The Trustee shall have no obligation or duty to monitor, determine or inquire as to compliance with any restrictions on transfer or exchange imposed under this Thirteenth Supplemental Indenture or under applicable law with respect to any registrations of transfer or exchange of any interest in any Series E Senior Note (including any transfers between or among members of, or participants in, the Depositary or beneficial owners of interests in any Global Security) other than to require delivery of such certificates and other documentation or evidence as are expressly required by, and to do so if and when expressly required by the terms of, this Thirteenth Supplemental Indenture, and to examine the same to determine substantial compliance as to form with the express requirements hereof.

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ARTICLE III
MISCELLANEOUS PROVISIONS

SECTION 301 Ratification and Incorporation of Base Indenture. As supplemented hereby, the Base Indenture is in all respects ratified and confirmed by the Company. The Base Indenture and this Thirteenth Supplemental Indenture shall be read, taken and construed as one and the same instrument.

SECTION 302 Executed in Counterparts. This Thirteenth Supplemental Indenture may be executed in several counterparts, each of which shall be deemed to be an original, and such counterparts shall together constitute but one and the same instrument. The exchange of copies of this Thirteenth Supplemental Indenture and of signature pages by facsimile or PDF transmission shall constitute effective execution and delivery of this Thirteenth Supplemental Indenture as to the parties hereto and may be used in lieu of the original, manually executed Thirteenth Supplemental Indenture for all purposes. Signatures of the parties hereto transmitted by facsimile or PDF shall be deemed to be their original signatures for all purposes.

SECTION 303 Assignment. The Company shall have the right at all times to assign any of its rights or obligations under the Indenture with respect to the Series E Senior Notes to a direct or indirect wholly owned subsidiary of the Company; provided that, in the event of any such assignment, the Company shall remain primarily liable for the performance of all such obligations. The Indenture may also be assigned by the Company in connection with a transaction described in Article VIII of the Base Indenture.

SECTION 304 Trustee's Disclaimer. All of the provisions contained in the Base Indenture in respect of the rights, powers, privileges, protections, duties and immunities of the Trustee, including without limitation its right to be indemnified, shall be applicable in respect of the Series E Senior Notes and of this Thirteenth Supplemental Indenture as fully and with like effect as if set forth herein in full. The Trustee accepts the amendments of the Indenture effected by this Thirteenth Supplemental Indenture, but on the terms and conditions set forth in the Indenture, including the terms and provisions defining and limiting the liabilities and responsibilities of the Trustee. Without limiting the generality of the foregoing, the Trustee shall not be responsible in any manner whatsoever for or with respect to any of the recitals or statements contained herein, all of which recitals or statements are made solely by the Company, or for or with respect to (i) the validity or sufficiency of this Thirteenth Supplemental Indenture or any of the terms or provision hereof, (ii) the proper authorization hereof by the Company by action or otherwise, (iii) the due execution hereof by the Company, or (iv) the consequences of any amendment herein provided for, and the Trustee makes no representation with respect to any such matters.

[Signature Page Follows]

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IN WITNESS WHEREOF, each party hereto has caused this instrument to be signed in its name and behalf by its duly authorized officer, all as of the day and year first above written.

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DOMINION ENERGY, INC.

By: /s/ James R. Chapman
Name: James R. Chapman
Title: Senior Vice President – Mergers & Acquisitions and Treasurer

DEUTSCHE BANK TRUST COMPANY AMERICAS, as Trustee

By: /s/ Carol Ng
Name: Carol Ng
Title: Vice President

By: /s/ James Briggs
Name: James Briggs
Title: Vice President

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EXHIBIT A

**FORM OF
2017 SERIES E FLOATING RATE SENIOR NOTE
DUE 2020**

[UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (55 WATER STREET, NEW YORK, NEW YORK) TO THE ISSUER OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND ANY CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF [CEDE & CO.] OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY AND ANY PAYMENT IS MADE TO [CEDE & CO.], ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL SINCE THE REGISTERED OWNER HEREOF, [CEDE & CO.], HAS AN INTEREST HEREIN.]**

[THIS SERIES E SENIOR NOTE IS A GLOBAL SECURITY WITHIN THE MEANING OF THE INDENTURE HEREINAFTER REFERRED TO AND IS REGISTERED IN THE NAME OF A DEPOSITARY OR A NOMINEE THEREOF. THIS SERIES E SENIOR NOTE MAY NOT BE EXCHANGED IN WHOLE OR IN PART FOR A SECURITY REGISTERED, AND NO TRANSFER OF THIS SERIES E SENIOR NOTE IN WHOLE OR IN PART MAY BE REGISTERED, IN THE NAME OF ANY PERSON OTHER THAN SUCH DEPOSITARY OR A NOMINEE THEREOF, EXCEPT IN THE LIMITED CIRCUMSTANCES DESCRIBED IN THE INDENTURE. EVERY SERIES E SENIOR NOTE AUTHENTICATED AND DELIVERED UPON REGISTRATION OF, TRANSFER OF, OR IN EXCHANGE FOR OR IN LIEU OF, THIS SERIES E SENIOR NOTE SHALL BE A GLOBAL SECURITY SUBJECT TO THE FOREGOING, EXCEPT IN SUCH LIMITED CIRCUMSTANCES.]***

[THIS SERIES E SENIOR NOTE (OR ITS PREDECESSOR) WAS ORIGINALLY ISSUED IN A TRANSACTION EXEMPT FROM REGISTRATION UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), AND THIS SERIES E SENIOR NOTE MAY NOT BE OFFERED, SOLD OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION OR AN APPLICABLE EXEMPTION THEREFROM. EACH PURCHASER OF THIS SERIES E SENIOR NOTE IS HEREBY NOTIFIED THAT THE SELLER OF THIS SERIES E SENIOR NOTE MAY BE RELYING ON THE EXEMPTION FROM THE PROVISIONS OF SECTION 5 OF THE SECURITIES ACT PROVIDED BY RULE 144A THEREUNDER.]****

[THE HOLDER OF THIS SERIES E SENIOR NOTE AGREES FOR THE BENEFIT OF THE COMPANY THAT (A) THIS SERIES E SENIOR NOTE MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED, ONLY (I) IN THE UNITED

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*** Insert in Global Securities.
**** Insert in Restricted Securities
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STATES TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (II) OUTSIDE THE UNITED STATES IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 904 UNDER THE SECURITIES ACT, (III) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE), (IV) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, OR (V) TO AN INSTITUTIONAL “ACCREDITED INVESTOR” (AS DEFINED IN RULE 501(A)(1), (2), (3) OR (7) OF REGULATION D UNDER THE SECURITIES ACT) THAT IS ACQUIRING THE NOTE FOR ITS OWN ACCOUNT, OR FOR THE ACCOUNT OF SUCH AN INSTITUTIONAL “ACCREDITED INVESTOR” FOR INVESTMENT PURPOSES AND NOT WITH A VIEW TO, OR FOR OFFER OR SALE IN CONNECTION WITH, ANY DISTRIBUTION IN VIOLATION OF THE SECURITIES ACT, IN EACH OF CASES (I) THROUGH (V) IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES, AND (B) THE HOLDER WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS SERIES E SENIOR NOTE FROM IT OF THE RESALE RESTRICTIONS REFERRED TO IN CLAUSE (A) ABOVE.]***

[THE HOLDER AGREES THAT IT WILL DELIVER TO EACH PERSON TO WHOM THIS SERIES E SENIOR NOTE OR AN INTEREST HEREIN IS TRANSFERRED A NOTICE SUBSTANTIALLY TO THE EFFECT OF THIS LEGEND.]***

[THE HOLDER AGREES THAT, BEFORE THE HOLDER OFFERS, SELLS OR OTHERWISE TRANSFERS THIS SERIES E SENIOR NOTE, THE COMPANY MAY REQUIRE THE HOLDER OF THIS SERIES E SENIOR NOTE TO DELIVER A WRITTEN OPINION, CERTIFICATIONS AND/OR OTHER INFORMATION THAT IT REASONABLY REQUIRES TO CONFIRM THAT SUCH PROPOSED TRANSFER IS BEING MADE PURSUANT TO AN EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE UNITED STATES.]***

[AS USED IN THIS SERIES E SENIOR NOTE, THE TERMS “OFFSHORE TRANSACTION,” “U.S. PERSON” AND “UNITED STATES” HAVE THE MEANINGS GIVEN TO THEM BY RULE 902 OF REGULATION S UNDER THE SECURITIES ACT.]***

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DOMINION ENERGY, INC.

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[Up to]**
$[______]
2017 SERIES E FLOATING RATE SENIOR NOTE
DUE 2020

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No. R- CUSIP No. ____________

Dominion Energy, Inc. (formerly Dominion Resources, Inc.), a corporation duly organized and existing under the laws of Virginia (herein called the "Company" or "Issuer", which terms include any successor Person under the Indenture hereinafter referred to), for value received, hereby promises to pay to [Cede & Co.]**, or registered assigns (the "Holder"), the principal sum [of ____________ Dollars ($______)] [subject to the increases and decreases set forth in Schedule I hereto]** on December 1, 2020 and to pay interest thereon from December 8, 2017 or from the most recent Interest Payment Date to which interest has been paid or duly provided for, quarterly in arrears on March 1, June 1, September 1 and December 1 of each year, commencing on March 1, 2018, at a floating rate per annum determined by Deutsche Bank Trust Company Americas, or its successors as calculation agent (the "Calculation Agent") in accordance with the procedures referred to herein, until the principal hereof is paid or made available for payment, provided that any principal, and any such installment of interest, that is overdue shall bear interest at the then applicable interest rate (to the extent that the payment of such interest shall be legally enforceable), from the dates such amounts are due until they are paid or made available for payment, and such interest shall be payable on demand. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in the Indenture referred to on the reverse hereof, be paid to the Person in whose name this Series E Senior Note (or one or more Predecessor Securities) is registered at the close of business on the Regular Record Date for such interest; provided that the interest payable at Stated Maturity will be paid to the Person to whom principal is payable. The Regular Record Date shall be the close of business on the Business Day preceding such Interest Payment Date; provided, that with respect to Series E Senior Notes that are not represented by one or more Global Securities, the Regular Record Date shall be the close of business on the fifteenth (15th) calendar day (whether or not a Business Day) preceding such Interest Payment Date. Any such interest not so punctually paid or duly provided for will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the Person in whose name this Series E Senior Note (or one or more Predecessor Securities) is registered at the close of business on a Special Record Date for the payment of such Defaulted Interest to be fixed by the Trustee, notice whereof shall be given to Holders of Series E Senior Notes not less than ten (10) days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange on which the Series E Senior Notes may be listed, and upon such notice as may be required by such exchange, all as more fully provided in the Indenture.

The per annum interest rate on the Series E Senior Notes will be equal to the Three Month LIBOR Rate plus 40 basis points (0.40%); provided that the per annum interest rate for

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the period from the Original Issue Date to the first LIBOR Rate Reset Date will be 1.52263% per annum (the "Initial Interest Rate"). The per annum interest rate shall be reset on each LIBOR Rate Reset Date.

If any LIBOR Rate Reset Date falls on a day that is not a Business Day, the LIBOR Rate Reset Date will be postponed to the next day that is a Business Day, except that if that Business Day is in the next succeeding calendar month, the LIBOR Rate Reset Date will be the next preceding Business Day. The interest rate in effect on any LIBOR Rate Reset Date will be the applicable rate as reset on that date. The interest rate applicable to any other day will either be the Initial Interest Rate or the interest rate as reset on the immediately preceding LIBOR Rate Reset Date.

Payments of interest on the Series E Senior Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series E Senior Notes shall be computed and paid on the basis of the actual number of days in the relevant quarterly period (including the first day of the quarterly period and excluding the last day of the quarterly period) divided by 360. In the event that any date on which interest is payable on the Series E Senior Notes is not a Business Day, then payment of the interest payable on such date will be made on the next succeeding day that is a Business Day (and without any interest or payment in respect of any such delay), except that if that business day is in the next succeeding calendar month, the Interest Payment Date will be the immediately preceding business day, in each case with the same force and effect as if made on the date the payment was originally payable.

Payment of the principal of and interest on this Series E Senior Note will be made at the office of the Paying Agent, in the Borough of Manhattan, City and State of New York, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts, with any such payment that is due at the Stated Maturity of any Series E Senior Note, or upon repurchase being made upon surrender of such Series E Senior Note to such office or agency; provided, however, that at the option of the Company payment of interest, subject to such surrender where applicable, may be made (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least sixteen (16) days prior to the date for payment by the Person entitled thereto.

Reference is hereby made to the further provisions of this Series E Senior Note set forth on the reverse hereof, which further provisions shall for all purposes have the same effect as if set forth at this place.

Unless the certificate of authentication hereon has been executed by the Trustee referred to on the reverse hereof by manual signature, this Series E Senior Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.
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IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed.

DOMINION ENERGY, INC.

By: ____________________________
Name: __________________________
Title: ___________________________

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This is one of the Securities of the series designated therein referred to in the within-mentioned Indenture.

DEUTSCHE BANK TRUST COMPANY AMERICAS, as Trustee

By: ____________________________
Authorized Signatory

Dated:

[REVERSE OF 2017 SERIES E FLOATING RATE SENIOR NOTE]

This Security is one of a duly authorized issue of securities of the Company (herein called the "Securities"), issued and to be issued in one or more series under an Indenture dated as of June 1, 2015 (the "Base Indenture"), between the Company and Deutsche Bank Trust Company Americas, as Trustee (the "Trustee"), as heretofore supplemented and as further supplemented by a Thirteenth Supplemental Indenture dated as of December 1, 2017 (the "Thirteenth Supplemental Indenture" and, together with the Base Indenture, as it may be hereafter supplemented or amended from time to time, the "Indenture," which term shall have the meaning assigned to it in such instrument), by and between the Company and the Trustee, and reference is hereby made to the Indenture for a statement of the respective rights, limitations of rights, duties and immunities thereunder of the Company, the Trustee and the Holders of the Securities and of the terms upon which the Securities are, and are to be, authenticated and delivered. This Security is one of the series designated on the face hereof (the "Series E Senior Notes") which is unlimited in aggregate principal amount.

The Series E Senior Notes are not redeemable at any time prior to the Stated Maturity.

If an Event of Default with respect to Series E Senior Notes shall occur and be continuing, the principal of the Series E Senior Notes may be declared due and payable in the manner and with the effect provided in the Indenture.

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Securities of each series to be affected under the Indenture at any time by the Company and the Trustee for the series of Securities affected, with the consent of the Holders of a majority in principal amount of the Securities at the time Outstanding of each series to be affected. The Indenture also contains provisions permitting the Holders of specified percentages in principal amount of the Securities of each series at the time Outstanding, on behalf of the Holders of all Securities of such series, to waive certain past defaults under the Indenture and their consequences. Any such consent or waiver by the Holder of this Series E Senior Note shall be conclusive and binding upon such Holder and upon all future Holders of this Series E Senior Note and of any Series E Senior Note issued upon the registration of transfer hereof or in exchange therefor or in lieu hereof, whether or not notation of such consent or waiver is made upon this Series E Senior Note.

As provided in and subject to the provisions of the Indenture, the Holder of this Series E Senior Note shall not have the right to institute any proceeding with respect to the Indenture or for the appointment of a receiver or trustee or for any other remedy thereunder, unless such Holder shall have previously given the Trustee written notice of a continuing Event of Default with respect to the Series E Senior Notes, the Holders of not less than a majority in principal amount of the Series E Senior Notes at the time Outstanding shall have made written request to the Trustee to institute proceedings in respect of such Event of Default as Trustee and offered the Trustee indemnity or security reasonably satisfactory to it, and the Trustee shall not have received from the Holders of a majority in principal amount of Series E Senior Notes at the time Outstanding a direction inconsistent with such request, and shall have failed to institute any such proceeding for sixty (60) days after receipt of such notice, request and offer of indemnity. The

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foregoing shall not apply to any suit instituted by the Holder of this Series E Senior Note for the enforcement of any payment of principal hereof or premium, if any, or interest hereon on or after the respective due dates expressed or provided for herein.

No reference herein to the Indenture and no provision of this Series E Senior Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of, premium, if any, and interest on this Series E Senior Note at the times, place and rate, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Series E Senior Note is registrable in the Security Register, upon surrender of this Series E Senior Note for registration of transfer at the office or agency of the Company in any place where the principal of, premium, if any, and interest on this Series E Senior Note are payable, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar duly executed by, the Holder hereof or his attorney duly authorized in writing, and thereupon one or more new Series E Senior Notes of like tenor, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

The Series E Senior Notes are issuable only in registered form without coupons in denominations of $2,000 and any greater integral multiple of $1,000. As provided in the Indenture and subject to certain limitations therein set forth, Series E Senior Notes are exchangeable for a like aggregate principal amount of Series E Senior Notes having the same Stated Maturity and of like tenor of any authorized denominations as requested by the Holder upon surrender of the Series E Senior Note or Series E Senior Notes to be exchanged at the office or agency of the Company.

No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Series E Senior Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Security is registered as the owner hereof for all purposes, whether or not this Series E Senior Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

All terms used in this Series E Senior Note that are defined in the Indenture shall have the meanings assigned to them in the Indenture.

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ABBREVIATIONS

The following abbreviations, when used in the inscription on the face of this instrument, shall be construed as though they were written out in full according to applicable laws or regulations:

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TEN COM -	as tenants in common
TEN ENT -	as tenants by the entireties
JT TEN -	as joint tenants with rights of survivorship and not as tenants in common
UNIF GIFT MIN ACT -	______________________ Custodian for (Cust) ______________________ (Minor) Under Uniform Gifts to Minors Act of ______________________ (State)

Additional abbreviations may also be used though not on the above list.

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FOR VALUE RECEIVED, the undersigned hereby sell(s) and transfer(s) unto

____.

(please insert Social Security or other identifying number of assignee)

____.

____.

____.

PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING POSTAL ZIP CODE OF ASSIGNEE

the within Series E Senior Note and all rights thereunder, hereby irrevocably constituting and appointing

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agent to transfer said Series E Senior Note on the books of the Company, with full power of substitution in the premises.

Dated:_______________ __, ____

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NOTICE: The signature to this assignment must correspond with the name as written upon the face of the within instrument in every particular without alteration or enlargement, or any change whatever.

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DOMINION ENERGY, INC.

2017 SERIES E SENIOR NOTE

DUE 2020

No. R-____

SCHEDULE I**

The initial principal amount of this Series E Senior Note is: $____

The following increases or decreases in this Global Security have been made:

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Date of increase or decrease and reason for the change in principal amount	Amount of decrease in principal amount of this Global Security	Amount of increase in principal amount of this Global Security	Principal amount of this Global Security following such decrease or increase	Signature of authorized signatory of Trustee

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EXHIBIT 10.43

DOMINION ENERGY, INC.
2018 PERFORMANCE GRANT PLAN

1. Purpose. The purpose of the 2018 Performance Grant Plan (the "Plan") is to set forth the terms of 2018 Performance Grants ("Performance Grants") awarded by Dominion Energy, Inc., a Virginia corporation (the "Company"). This Plan contains the performance goals for the awards, the performance criteria, the target and maximum amounts payable, and other applicable terms and conditions.

2. Definitions.

a. Beneficiary. Means the individual, individuals, entity, entities or the estate of a Participant entitled to receive the amounts payable under a Performance Grant, if any, upon the Participant's death.

b. Cause. For purposes of this Plan, the term "Cause" will have the meaning assigned to that term under a Participant's Employment Continuity Agreement with the Company, as such Agreement may be amended from time to time.

c. Committee. Means the Compensation, Governance and Nominating Committee of the board of directors of the Company (or any successor board committee designated by the board of directors of the Company to administer this Plan).

d. Date of Grant. February 1, 2018.

e. Disability or Disabled. Means a "disability" as defined under Treasury Regulation Section 1.409A-3(i)(4). The Committee will determine whether or not a Disability exists and its determination will be conclusive and binding on the Participant.

f. Dominion Company. Means any corporation or other entity in which the Company owns stock or other equity possessing at least 50% of the combined voting power of all classes of stock or other equity or which is in a chain of corporations or other entities with the Company in which stock or other equity possessing at least 50% of the combined voting power of all classes of stock or other equity is owned by one or more other corporations or other entities in the chain.

g. Participant. An officer of the Company or a Dominion Company who receives a Performance Grant on the Date of Grant.

h. Performance Period. The 36-month period beginning on January 1, 2018 and ending on December 31, 2020.

i. Price-Earnings Ratio. The closing price of a share of common stock on the last trading day of the Performance Period divided by the annual operating earnings per share reported for the 12-month period ending on the last day of the Performance Period.

j. Retire or Retirement. For purposes of this Plan, the term Retire or Retirement means a voluntary termination of employment on a date when the Participant is eligible for early or normal retirement benefits under the terms of the Dominion Energy

Pension Plan, or would be eligible if any crediting of deemed additional years of age or service applicable to the Participant under the Company's Benefit Restoration Plan or New Benefit Restoration Plan was applied under the Dominion Energy Pension Plan, as in effect at the time of the determination, unless the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's retirement is detrimental to the Company.

k. Target Amount. The dollar amount designated in the written notice to the Participant communicating the Performance Grant.

3. Performance Grants. A Participant will receive a written notice of the amount designated as the Participant's Target Amount for the Performance Grant payable under the terms of this Plan. The actual payout may be from 0% to 200% of the Target Amount, depending on the achievement of the performance goals.

4. Performance Achievement and Time of Payment. Upon the completion of the Performance Period, the Committee will determine the final performance goal achievement of each of the performance criteria described in Section 6. The Company will then calculate the final amount of each Participant's Performance Grant based on such performance goal achievement. Except as provided in Sections 7(b) or 8, the Committee will determine the time of payout of the Performance Grants, provided that in no event will payment be made later than March 15, 2021. Performance Grants shall be paid in cash.

5. Forfeiture. Except as provided in Sections 7 and 8, a Participant's right to payout of a Performance Grant will be forfeited if the Participant's employment with the Company or a Dominion Company terminates for any reason before the end of the Performance Period.

6. Performance Goals. Payout of Performance Grants will be based on the performance goal achievement of the performance criteria described in this Section 6 and further defined in Exhibit A.

a. TSR Performance. Total Shareholder Return Performance ("TSR Performance") will determine fifty percent (50%) of the Target Amount ("TSR Percentage"). TSR Performance is defined in Exhibit A. The percentage of the TSR Percentage that will be paid out, if any, is based on the following table:

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Relative TSR Performance Percentile Ranking	Percentage Payout of TSR Percentage
85th or above	200%
50th	100%
25th	50%
Below 25th	0%

To the extent that the Company's Relative TSR Performance ranks in a percentile between the 25th and 85th percentile in the table above, then the TSR Percentage payout will be interpolated between the corresponding TSR Percentage payout set forth above. No payment of the TSR Percentage will be made if the Relative TSR Performance is below the 25th percentile, except that a payment of 25% of the TSR Percentage will be made if the Company's Relative TSR Performance is below the 25th percentile but its Absolute

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TSR Performance is at least 9%. In addition to the foregoing payments, and regardless of the Company's Relative TSR Performance, either (but not both) of the following may be earned: (i) an additional payment of 25% of the TSR Percentage will be made if the Company's Absolute TSR Performance is at least 10% but less than 15%, and/or if the Company's Price-Earnings Ratio is at or above the 50th percentile and below the top third of the group of companies (inclusive of the Company) used to measure Relative TSR Performance in accordance with Exhibit A hereto, or (ii) an additional payment of 50% of the TSR Percentage will be made if the Company's Absolute TSR Performance is at least 15%, and/or if the Company's Price-Earnings Ratio is at or above the top third of the group of companies (inclusive of the Company) used to measure Relative TSR Performance in accordance with Exhibit A hereto (in either case, the "Performance Adder"). The Committee may reduce or eliminate payment of the Performance Adder in its sole discretion.

The aggregate payments under this Section 6(a) may not exceed 250% of the TSR Percentage. In addition, the overall percentage payment under the entire Performance Grant may not exceed 200%.

b. ROIC Performance. Return on Invested Capital Performance ("ROIC Performance") will determine fifty percent (50%) of the Target Amount ("ROIC Percentage"). ROIC Performance is defined in Exhibit A. The percentage of the ROIC Percentage that will be paid out, if any, is based on the following table:

ROIC Performance	Percentage Payout of ROIC Percentage
7.16% and above	200%
6.87%	100%
6.55%	50%
Below 6.55%	0%

- To the extent that the Company's ROIC Performance is greater than 6.55% and less than 6.87%, the ROIC Percentage payout will be interpolated between the applicable Percentage Payout of ROIC Percentage range set forth above.
- To the extent that the Company's ROIC Performance is greater than 6.87% and less than 7.16%, the ROIC Percentage payout will be interpolated between the applicable Percentage Payout of ROIC Percentage range set forth above.

7. Retirement, Involuntary Termination without Cause, Death or Disability.

a. Retirement or Involuntary Termination without Cause. Except as provided in Section 8, if a Participant Retires during the Performance Period or if a Participant's employment is involuntarily terminated by the Company or a Dominion Company without Cause during the Performance Period, and in either case the Participant would have been eligible for a payment if the Participant had remained employed until the end of the Performance Period, the Participant will receive a pro-rated payout of the Participant's Performance Grant equal to the payment the Participant would have received had the Participant remained employed until the end of the Performance Period multiplied by a fraction, the numerator of which is the number of whole months from the Date of Grant to the first day of the month coinciding with or immediately following the date of the Participant's retirement or termination of employment, and the denominator of which is thirty-five (35). Payment will be made after the end of the Performance Period at the time provided in Section 4 based on the performance goal achievement approved by the Committee. If the Participant Retires, however, no payment will be made if the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's Retirement is detrimental to the Company.

b. Death or Disability. If, while employed by the Company or a Dominion Company, a Participant dies or becomes Disabled during the Performance Period, the Participant or, in the event of the Participant's death, the Participant's Beneficiary will receive a lump sum cash payment equal to the product of (i) and (ii) where:

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(i) is the amount that would be paid based on the predicted performance used for determining the compensation cost recognized by the Company for the Participant's Performance Grant for the latest financial statement filed with the Company's Annual Report on Form 10-K or Quarterly Report on Form 10-Q immediately prior to the event; and

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(ii) is a fraction, the numerator of which is the number of whole months from the Date of Grant to the first day of the calendar month coinciding with or immediately following the date of the Participant's death or Disability, and the denominator of which is thirty-five (35).

Payment under this Section 7(b) will be made as soon as administratively feasible (and in any event within sixty (60) days) after the date of the Participant's death or Disability, and the Participant shall not have the right to any further payment under this Agreement. In the event of the Participant's death, payment will be made to the Participant's designated Beneficiary.

8. Qualifying Change of Control. Upon a Qualifying Change of Control (as defined in the Company's 2014 Incentive Compensation Plan, as amended) prior to the end of the Performance Period, provided the Participant has remained continuously employed with the Company or a Dominion Company from the Date of Grant to the date of the Qualifying Change of Control, the Participant will receive a lump sum cash payment equal to the greater of (i) the Target Amount or (ii) the total payout that would be made at the end of the Performance Period if the predicted performance used for determining the compensation cost recognized by the Company for the Participant's Performance Grant for the latest financial statement filed with the Company's Annual Report on Form 10-K or Quarterly Report on Form 10-Q immediately prior to the Qualifying Change of Control was the actual performance for the Performance Period (in either case, the "COC Payout Amount"). Payment will be made on or as soon as administratively feasible following the Qualifying Change of Control date and in no event later than sixty (60) days following the Qualifying Change of Control date. If a Qualifying Change of Control occurs prior to the end of the Performance Period and after a Participant has Retired or been involuntarily terminated without Cause pursuant to Section 7(a) above, then the Participant will receive a pro-rated payout of the Participant's Performance Grant, equal to the COC Payout Amount multiplied by the fraction set forth in Section 7(a) above, with payment occurring in a cash lump sum on or as soon as administratively feasible (but in any event within sixty (60) days) after the Qualifying Change of Control date. Following any payment under this Section 8, the Participant shall not have the right to any further payment under this Agreement.

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9. Termination for Cause. Notwithstanding any provision of this Plan to the contrary, if the Participant's employment with the Company or a Dominion Company is terminated for Cause (as defined by the Employment Continuity Agreement between the Participant and the Company), the Participant will forfeit all rights to his or her Performance Grant.

10. Clawback of Award Payment.

a. Restatement of Financial Statements. If the Company's financial statements are required to be restated at any time within a two (2) year period following the end of the Performance Period as a result of fraud or intentional misconduct, the Committee may, in its discretion, based on the facts and circumstances surrounding the restatement, direct the Company to recover all or a portion of the Performance Grant payout from the Participant if the Participant's conduct directly caused or partially caused the need for the restatement.

b. Fraudulent or Intentional Misconduct. If the Company determines that the Participant has engaged in fraudulent or intentional misconduct related to or materially affecting the Company's business operations or the Participant's duties at the Company, the Committee may, in its discretion, based on the facts and circumstances surrounding the misconduct, direct the Company to withhold payment, or if payment has been made, to recover all or a portion of the Performance Grant payout from the Participant.

c. Recovery of Payout. The Company reserves the right to recover a Performance Grant payout pursuant to this Section 10 by (i) seeking repayment from the Participant; (ii) reducing the amount that would otherwise be payable to the Participant under another Company benefit plan or compensation program to the extent permitted by applicable law; (iii) withholding future annual and long-term incentive awards or salary increases; or (iv) taking any combination of these actions.

d. No Limitation on Remedies. The Company's right to recover a Performance Grant payout pursuant to this Section 10 shall be in addition to, and not in lieu of, actions the Company may take to remedy or discipline a Participant's misconduct including, but not limited to, termination of employment or initiation of a legal action for breach of fiduciary duty.

e. Subject to Future Rulemaking. The Performance Grant payout is subject to any claw back policies the Company may adopt in order to conform to the requirements of Section 954 of the Dodd-Frank Wall Street Reform Act and Consumer Protection Act and resulting rules issued by the Securities and Exchange Commission or national securities exchanges thereunder and that the Company determines should apply to this Performance Grant Plan.

11. Miscellaneous.

a. Nontransferability. Except as provided in Section 7(b), a Performance Grant is not transferable and is subject to a substantial risk of forfeiture until the end of the Performance Period.

b. No Right to Continued Employment. A Performance Grant does not confer upon a Participant any right with respect to continuance of employment by the Company, nor will it interfere in any way with the right of the Company to terminate a Participant's employment at any time.

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c. Tax Withholding. The Company will withhold Applicable Withholding Taxes from the payout of Performance Grants.

d. Performance Goal Adjustments. The Committee may at any time, in its sole discretion, remove or revise any performance goals or other performance objectives for this 2018 Performance Grant Plan. The Committee retains the authority to exercise negative discretion to reduce payments under this Plan as it deems appropriate.

e. Governing Law. This Plan shall be governed by the laws of the Commonwealth of Virginia, without regard to its choice of law provisions.

f. Binding Effect. This Plan will be binding upon and inure to the benefit of the legatees, distributes, and personal representatives of Participants and any successors of the Company.

g. Section 409A. This Plan and the Performance Grants hereunder are intended to comply with Section 409A of the Internal Revenue Code of 1986, as amended ("Code Section 409A"), and shall be interpreted to the maximum extent possible in accordance with such intent. To the extent necessary to comply with Code Section 409A, no payment will be made earlier than six months after a Participant's termination of employment other than for death if the Performance Grant is subject to Code Section 409A and the Participant is a "specified employee" (within the meaning of Code Section 409A(a)(2)(B)(i)).

h. Administration. The Plan shall be administered by the Committee, which shall have all of the applicable powers and authority set forth in Section 19 of the Company's 2014 Incentive Compensation Plan with respect to this Plan and the Performance Grants awarded hereunder, the terms of which are incorporated by reference herein.

i. Termination and Amendment. The Committee may amend the Plan and Performance Grants awarded hereunder, provided that, except as otherwise provided herein, no termination or amendment of the Plan or any Performance Grants under the Plan shall materially adversely affect a Participant's rights with respect to any outstanding Performance Grant without that Participant's consent. Notwithstanding the foregoing, the Committee may amend the Plan and Performance Grants awarded hereunder without having to obtain the consent of any affected Participant as it deems necessary or appropriate to ensure compliance with applicable laws or to cause Performance Grants to avoid adverse tax consequences under the Code and regulations thereunder.

j. Notice. All notices and other communications required or permitted to be given under this Plan shall be in writing and shall be deemed to have been duly given if delivered personally or mailed first class, postage prepaid, as follows: (a) if to the Company—at the principal business address of the Company to the attention of the Corporate Secretary of the Company; and (b) if to any Participant—at the last address of the Participant known to the sender at the time the notice or other communication is sent.

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k. Interpretation. Unless otherwise specifically provided under the terms of any such plan or program, settlements of awards received by participants under the Plan shall not be deemed a part of a participant's regular, recurring compensation for purposes of calculating payments or benefits from any benefit plan or severance program of the Company or a Dominion Company or any severance pay law of any country. Nothing contained in the Plan will be deemed in any way to limit or restrict the Company or any Dominion Company from making any award or payment to any person under any other plan, arrangement or understanding, whether now existing or hereafter in effect. The terms of this Plan shall be governed by the laws of the Commonwealth of Virginia, without regard to its conflict of law principles.

l. Beneficiary Matters. A Participant may designate a Beneficiary to receive benefits due under a Performance Grant, if any, upon the Participant's death. Designation of a Beneficiary shall be made by execution of a form approved or accepted by the Committee. In the absence of a valid Beneficiary designation, a Participant's surviving spouse, if any, and if none, the Participant's estate, shall be the Beneficiary. A Participant may change a prior Beneficiary designation by a subsequent execution of a new Beneficiary designation form. The change in Beneficiary will be effective upon receipt by the Committee. Any payment made to a Beneficiary under this Plan in good faith shall fully discharge the Company and the Dominion Companies from all further obligations with respect to that payment. If the Committee has any doubt as to the proper Beneficiary to receive a payment under this Plan, the Committee shall have the right to withhold such payment until the matter is fully adjudicated. In making any payment to or for the benefit of any minor or an incompetent Participant or Beneficiary, the administrator, in its sole and absolute discretion, may make a distribution to a legal or natural guardian or other relative of a minor or court-appointed representative of such incompetent. Alternatively, it may make a payment to any adult with whom the minor or incompetent temporarily or permanently resides. The receipt by a guardian, representative, relative or other person shall be a complete discharge of the Company and the Dominion Companies' obligations under the Plan. The Company shall have no responsibility to see to the proper application of any payment so made. The Plan shall be binding on all successors and assigns of a Participant, including, without limitation, the estate of such participant and the executor, administrator or trustee of such estate, or any receiver or trustee in bankruptcy or representative of the Participant's creditors.

m. Unfunded Plan. Unless otherwise determined by the Committee, the Plan shall be unfunded and shall not create (or be construed to create) a trust or a separate fund or funds. The Plan shall not establish any fiduciary relationship between the Company and any Participant or other person. To the extent any person holds any rights by virtue of a Performance Grant granted under the Plan, such rights (unless otherwise determined by the Committee) shall be no greater than the rights of an unsecured general creditor of the Company.

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EXHIBIT A

DOMINION ENERGY, INC.
2018 PERFORMANCE GRANT PLAN
PERFORMANCE CRITERIA

Total Shareholder Return

Relative TSR Performance will be measured based on where the Company's total shareholder return during the Performance Period ranks in relation to the total shareholder returns of the companies that are members of the Company's compensation peer group as of the Grant Date as set forth below (the "Comparison Companies"):

Ameren Corporation
American Electric Power Company
CenterPoint Energy
Consolidated Edison Company
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Eversource Energy
Exelon Corporation
FirstEnergy Corporation
NextEra Energy
PG&E Corporation
PPL Corporation
Public Service Enterprise Group
Southern Company
Xcel Energy

The Comparison Companies shall be adjusted during the Performance Period as follows:

(i) In the event of a merger, acquisition or business combination transaction of a Comparison Company with or by another Comparison Company, effective upon the public announcement of the transaction, the surviving entity shall remain a Comparison Company and the non-surviving entity shall cease to be a Comparison Company (provided that, if the proposed transaction is subsequently terminated before the Relative TSR Performance is calculated, then the non-surviving company shall be retroactively reinstated as a Comparison Company);

(ii) If it is publicly announced that a Comparison Company will be acquired by another company that is not a Comparison Company, or in the event a "going private transaction" is publicly announced where the Comparison Company will not be the surviving entity or will otherwise no longer be publicly traded, the company shall cease to be a Comparison Company as of the date such announcement is made (provided that, if the proposed transaction is subsequently terminated before the Relative TSR Performance is calculated, then the company shall be retroactively reinstated as a Comparison Company);

(iii) In the event of a spinoff, divestiture, or sale of assets of a Comparison Company, the Comparison Company shall no longer be a Comparison Company if the company's reported revenue for the four most recently reported quarters ending on or before the last day of the Performance Period falls below 40% of Dominion Energy's reported revenue for last year of the Performance Period; and

(iv) In the event of a bankruptcy of a Comparison Company, such company shall remain a Comparison Company and its stock price will continue to be tracked for purposes of Relative TSR Performance. If the company liquidates, it will remain a Comparison Company and its stock price will be reduced to zero for the remaining Performance Period.

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Absolute TSR Performance will be the Company's total shareholder return on an average annual basis for the Performance Period. In general, total shareholder return consists of the difference between the value of a share of common stock at the beginning and end of the Performance Period, plus the value of dividends paid as if reinvested in stock and other appropriate adjustments for such events as stock splits. For purposes of TSR Performance, the total shareholder return of the Company and the Comparison Companies will be calculated using Bloomberg L.P. As soon as practicable after the completion of the Performance Period, the total shareholder returns of the Comparison Companies will be obtained from Bloomberg L.P. and ranked from highest to lowest by the Committee. The Company's total shareholder return will then be ranked in terms of which percentile it would have placed in among the Comparison Companies.

Price-Earnings Ratio performance will be measured based on where the Company's Price-Earnings Ratio ranks in relation to the Price-Earnings Ratios of the Comparison Companies as determined above. For purposes of Price-Earnings Ratio performance, the Price-Earnings Ratio of the Company and the Comparison Companies will be calculated using such method as the Committee shall determine. As soon as practicable after the completion of the Performance Period, the Price-Earnings Ratios of the Comparison Companies will be determined and ranked from highest to lowest by the Committee. The Company's Price-Earnings Ratio will then be ranked in terms of which percentile it would have placed in among the Comparison Companies.

Return on Invested Capital

Return on Invested Capital (ROIC)

The following terms are used to calculate ROIC for purposes of the 2018 Performance Grant:

ROIC means Total Return divided by Average Invested Capital. Performance will be calculated for the three successive fiscal years within the Performance Period, added together and then divided by three to arrive at an annual average ROIC for the Performance Period.

Total Return means Operating Earnings plus After-tax Interest & Related Charges, all determined for the three successive fiscal years within the Performance Period.

Operating Earnings means operating earnings as disclosed on the Company's earnings report furnished on Form 8-K for the applicable fiscal year.

Average Invested Capital means the Average Balances for Long & Short-term Debt plus Preferred Equity plus Common Shareholders' Equity. The Average Balances for a year are calculated by performing the calculation at the end of each month during the fiscal year plus the last month of the prior fiscal year and then averaging those amounts over 13 months. Long and short-term debt shall exclude debt that is non-recourse to Dominion Energy, Inc. (Dominion Energy) or its subsidiaries where Dominion Energy or its subsidiaries has not made an associated investment. Short-term debt shall be net of cash and cash equivalents.

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EXHIBIT A

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Average Invested Capital will be calculated by excluding (i) accumulated other comprehensive income/(loss) from Common Shareholders' Equity (as shown on the Company's financial statements during the Performance Period); (ii) impacts from changes in accounting principles that were not prescribed as of the Date of Grant; and (iii) the effects of incremental impacts from non-operating gains or losses during the Performance Period, as disclosed on the Company's earnings report furnished on Form 8-K, that were not included in the projection on which the original ROIC calculation was based at the time of the grant.

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EXHIBIT 10.44

DOMINION ENERGY, INC.
RESTRICTED STOCK AWARD AGREEMENT

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PARTICIPANT	DATE OF GRANT	NUMBER OF SHARES OF RESTRICTED STOCK GRANTED	
«First_Name» «Last_Name»	January 31, 2018	«##,###»	
PERSONNEL NUMBER	**VESTING DATE**	**VESTING SCHEDULE**	
		Vesting Date	**Percentage**
«#####»	February 1, 2021	February 1, 2021	100%

THIS AGREEMENT, effective as of the Date of Grant shown above, between Dominion Energy, Inc., a Virginia corporation (the "Company") and the Participant named above is made pursuant and subject to the provisions of the Dominion Energy, Inc. 2014 Incentive Compensation Plan and any amendments thereto (the "Plan"). All terms used in this Agreement that are defined in the Plan have the same meaning given to such terms in the Plan.

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1. Award of Stock. Pursuant to the Plan, the Number of Shares of Restricted Stock Granted shown above (the "Restricted Stock") were awarded to the Participant on the Date of Grant shown above, subject to the terms and conditions of the Plan, and subject further to the terms and conditions set forth in this Agreement.

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2. Vesting. Except as provided in Sections 3, 4, 5 or 6, one hundred percent (100%) of the shares of Restricted Stock awarded under this Agreement will vest on the Vesting Date shown above.

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3. Forfeiture. Except as provided in Sections 4 or 5, the Participant will forfeit any and all rights in the Restricted Stock if the Participant's employment with the Company or a Dominion Company terminates for any reason prior to the Vesting Date.

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4. Death, Disability, Retirement or Involuntary Termination without Cause. Except as provided in Section 5, if the Participant terminates employment due to death, Disability, or Retirement (as such term is defined in Section 8(e)) before the Vesting Date or if the Participant's employment is involuntarily terminated by the Company or a Dominion Company without Cause (as defined in the Employment Continuity Agreement between the Participant and the Company) before the Vesting Date, the Participant will become vested in the number of shares of Restricted Stock awarded under this Agreement multiplied by a fraction, the numerator of which is the number of whole months from February 1, 2018 to the first day of the month coinciding with or immediately following the date of the Participant's termination of employment, and the denominator of which is the number of whole months from February 1, 2018 to the Vesting Date, rounded down to the nearest whole share. If the Participant Retires, however, the Participant's Restricted Stock will not vest if the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's Retirement is detrimental to the Company. The vesting will occur on the date of the Participant's termination of employment due to death, Disability, Retirement, or termination by the Company without Cause. Any shares of Restricted Stock that do not vest in accordance with this Section 4 will be forfeited.

5. Change of Control. Upon a Change of Control prior to the Vesting Date, provided the Participant has remained continuously employed with the Company or a Dominion Company from the Date of Grant to the date of the Change of Control, the Participant's rights in the Restricted Stock will become vested as follows:

a. A portion of the Restricted Stock will be immediately vested equal to the number of shares of Restricted Stock awarded under this Agreement multiplied by a fraction, the numerator of which is the number of whole months from February 1, 2018 to the Change of Control date, and the denominator of which is the number of whole months from February 1, 2018 to the Vesting Date, rounded down to the nearest whole share.

b. Unless previously forfeited, the remaining shares of Restricted Stock will become vested after a Change of Control at the earliest of the following events and in accordance with the terms described in subsections (i) through (iii) below:

(i) Vesting Date. All remaining shares of Restricted Stock will become vested on the Vesting Date.

(ii) Death, Disability or Retirement. If the Participant terminates employment due to death, Disability or Retirement (as defined in Section 8(e)) before the Vesting Date, the Participant will become vested in the remaining shares of Restricted Stock multiplied by a fraction, the numerator of which is the number of whole months from the first day of the month in which the Change of Control occurs to the first day of the month coinciding with or immediately following the Participant's termination of employment, and the denominator of which is the number of whole months from the first day of the month in which the Change of Control occurs to the Vesting Date, rounded down to the nearest whole share. If the Participant Retires, however, the Participant's Restricted Stock will not vest if the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the

Participant's Retirement is detrimental to the Company. The vesting will occur on the date of the Participant's termination of employment due to death, Disability, or Retirement. Any shares of the Restricted Stock that do not vest in accordance with the terms of this subsection (ii) will be forfeited.

(iii) Involuntary Termination without Cause. All remaining shares of Restricted Stock will become vested upon the Participant's involuntary termination by the Company or a Dominion Company without Cause before the Vesting Date, or upon the Participant's Constructive Termination before the Vesting Date, as such terms are defined by the Employment Continuity Agreement between the Participant and the Company.

6. Termination for Cause. Notwithstanding any provision of this Agreement to the contrary, if the Participant's employment with the Company or a Dominion Company is terminated for Cause (as defined by the Employment Continuity Agreement between the Participant and the Company), the Participant will forfeit all Restricted Stock shares awarded pursuant to this Agreement.

7. Clawback of Award Payment.

a. Restatement of Financial Statements. If the Company's financial statements are required to be restated at any time within a two (2) year period following the Vesting Date as a result of fraud or intentional misconduct, the Committee may, in its discretion, based on the facts and circumstances surrounding the restatement, direct the Company to withhold issuance of all or a portion of the shares granted pursuant to this Agreement, or if shares have been issued, to recover all or a portion of the shares from the Participant if the Participant's conduct directly caused or partially caused the need for the restatement.

b. Fraudulent or Intentional Misconduct. If the Company determines that the Participant has engaged in fraudulent or intentional misconduct related to or materially affecting the Company's business operations or the Participant's duties at the Company, the Committee may, in its discretion, based on the facts and circumstances surrounding the misconduct, direct the Company to withhold issuance of all or a portion of the shares granted pursuant to this Agreement, or if shares have been issued, to recover all or a portion of the shares from the Participant.

c. Recovery of Payout. The Company reserves the right to recover a Restricted Stock Award payout pursuant to this Section 7 by (i) seeking recovery of the vested shares from the Participant; (ii) reducing the amount that would otherwise be payable to the Participant under another Company benefit plan or compensation program to the extent permitted by applicable law; (iii) withholding future annual and long-term incentive awards or salary increases; or (iv) taking any combination of these actions.

d. No Limitation on Remedies. The Company's right to recover Restricted Stock or issued shares pursuant to this Section 7 shall be in addition to, and not in lieu of, actions the Company may take to remedy or discipline a Participant's misconduct including, but not limited to, termination of employment or initiation of a legal action for breach of fiduciary duty.

e. Subject to Future Rulemaking. The Restricted Stock granted under this Agreement is subject to any claw back policies the Company may adopt in order to conform to the requirements of Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act and resulting rules issued by the Securities and Exchange Commission or national securities exchanges thereunder and that the Company determines should apply to said Restricted Stock.

8. Terms and Conditions.

a. Nontransferability. Except as provided in Sections 4 and 5, the shares of Restricted Stock are not transferable and are subject to a substantial risk of forfeiture until the Vesting Date.

b. Uncertificated Shares; Power of Attorney. The Company may issue the Restricted Shares in uncertificated form. Such uncertificated shares shall be credited to a book entry account maintained by the Company (or its transfer agent) on behalf of the Participant. As a condition of accepting this award, the Participant hereby irrevocably appoints Dominion Energy Services, Inc., or its successor, as the Participant's attorney-in-fact, with full power of substitution, to transfer (or provide instructions to the Company's transfer agent to transfer) such shares on the Company's books.

c. Custody of Share Certificates; Stock Power. The Company will retain custody of any share certificates for the Restricted Stock that may be issued until such shares vest or are forfeited. If share certificates are issued, the Participant shall execute and deliver a stock power, endorsed in blank, to Dominion Energy Services, Inc., with respect to such shares.

d. Shareholder Rights. The Participant will have the right to receive dividends and will have the right to vote the shares of Restricted Stock awarded under Section 1, both vested and unvested.

e. Retirement. For purposes of this Agreement, the term Retire or Retirement means a voluntary termination when the Participant is eligible for early or normal retirement benefits under the terms of the Dominion

Energy Pension Plan, or would be eligible if any crediting of deemed additional years of age or service applicable to the Participant under the Company's Benefit Restoration Plan or New Benefit Restoration Plan was applied under the Pension Plan, as in effect at the time of the determination, unless the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's retirement is detrimental to the Company.

f. Delivery of Shares.

(i) Share Delivery. On or as soon as administratively feasible after the Vesting Date or the date on which the shares of Restricted Stock have become vested due to the occurrence of an event described in Section 4 or 5, the Company will remove (or provide instructions to its transfer agents to remove) the transfer restrictions described herein, and (if any share certificate has been issued) shall deliver to the Participant (or in the event of the Participant's death, the Participant's Beneficiary) any such certificates free of the transfer restrictions described herein. The Company will also cancel any stock power covering such shares.

(ii) Withholding of Taxes. No Company Stock will be delivered until the Participant (or the Participant's Beneficiary) has paid to the Company the amount that must be withheld under federal, state and local income and employment tax laws (the "Applicable Withholding Taxes") or the Participant and the Company have made satisfactory arrangements for the payment of such taxes. Unless the Participant makes an alternative election, the Company will retain the number of shares of Restricted Stock (valued at their Fair Market Value) required to satisfy the Applicable Withholding Taxes. As an alternative to the Company retaining shares, the Participant or the Participant's Beneficiary may elect to (i) deliver Mature Shares (valued at their Fair Market Value) or (ii) make a cash payment to satisfy Applicable Withholding Taxes.

g. Fractional Shares. Fractional shares of Company Stock will not be issued.

h. No Right to Continued Employment. This Agreement does not confer upon the Participant any right with respect to continuance of employment by the Company or a Dominion Company, nor shall it interfere in any way with the right of the Company or a Dominion Company to terminate the Participant's employment at any time.

i. Change in Capital Structure. The number and fair market value of shares of Restricted Stock awarded by this Agreement shall be automatically adjusted as provided in Section 18(a) of the Plan if the Company has a change in capital structure.

j. <u>Governing Law</u>. This Agreement shall be governed by the laws of the Commonwealth of Virginia, other than its choice of law provisions.

k. <u>Conflicts</u>. In the event of any conflict between the provisions of the Plan and the provisions of this Agreement, the provisions of the Plan shall govern.

l. <u>Participant Bound by Plan</u>. By accepting this Agreement, Participant hereby acknowledges receipt of a copy of the prospectus and Plan document accessible on the Company Intranet and agrees to be bound by all the terms and provisions thereof.

m. <u>Binding Effect</u>. This Agreement shall be binding upon and inure to the benefit of the legatees, distributees, and personal representatives of the Participant and any successors of the Company.

EXHIBIT 10.45

Dominion Energy, Inc.
2018 Base Salaries for Named Executive Officers*

The 2018 base salaries for Dominion Energy's named executive officers are as follows: Thomas F. Farrell, II, Chairman, President and Chief Executive Officer—$1,554,992; Mark F. McGettrick, Executive Vice President and Chief Financial Officer—$906,223; Paul D. Koonce, Executive Vice President and President and Chief Executive Officer—Power Generation Group—$739,158; Diane Leopold, Executive Vice President and President and Chief Executive Officer—Gas Infrastructure Group—$623,150; and Robert M. Blue, Executive Vice President and President and Chief Executive Officer—Power Delivery Group—$623,150.

* Effective March 1, 2018

Exhibit 10.46

Dominion Energy, Inc.
Non-Employee Directors' Annual Compensation
As of December 31, 2017

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Annual Retainer	Amount
Service as Director	$265,000 ($107,500 cash; $157,500 stock)
Service as Audit Committee or Compensation, Governance and Nominating Committee Chair	$25,000
Service as Finance and Risk Oversight Committee Chair	$15,000
Service as Lead Director	$30,000

Meeting Fees

An excess meeting fee of $2,000 will be paid to each director who attends more than 25 meetings per calendar year, including Board and Committee meetings but not special education sessions, for each such meeting in excess of 25.

Exhibit 12.1

Dominion Energy, Inc. and Subsidiaries
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

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	Years Ended December 31,				
	2017(a)	2016(b)	2015(c)	2014(d)	2013(e)
Earnings, as defined:					
Income from continuing operations including noncontrolling interest before income tax expense (benefit)	$3,090	$2,867	$2,828	$1,778	$2,704
Distributed income from unconsolidated investees, less equity in earnings	177	(32)	12	(8)	17
Fixed charges included in income	1,276	1,068	953	1,237	930
Total earnings, as defined	$4,543	$3,903	$3,793	$3,007	$3,651
Fixed charges, as defined:					
Interest charges	$1,238	$1,033	$ 920	$1,208	$ 899
Rental interest factor	38	35	33	29	31
Fixed charges included in income	$1,276	$1,068	$ 953	$1,237	$ 930
Preference security dividend requirement of consolidated subsidiary	23	2	—	17	25
Capitalized interest	164	124	67	39	28
Interest from discontinued operations	—	—	—	—	85
Total fixed charges, as defined	$1,463	$1,194	$1,020	$1,293	$1,068
Ratio of Earnings to Fixed Charges	**3.11**	**3.27**	**3.72**	**2.33**	**3.42**

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(a) Earnings for the twelve months ended December 31, 2017 include $158 million of charges associated with our equity method investments in wind-powered generation facilities; $72 million in transition and integration costs primarily associated with Dominion Energy's acquisition of Dominion Energy Questar; and a $51 million charge related to other items, partially offset by $46 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the net effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2017.

(b) Earnings for the twelve months ended December 31, 2016 include a $197 million charge associated with ash pond and landfill closure costs; a $65 million charge associated with an organizational design initiative; a $74 million in transaction and transition costs associated with Dominion Energy's acquisition of Dominion Energy Questar; a $23 million charge related to storm and restoration costs; and a $45 million charge related to other items, partially offset by $34 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the net effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2016.

(c) Earnings for the twelve months ended December 31, 2015 include an $85 million write-off of prior-period deferred fuel costs associated with Virginia legislation; a $99 million charge associated with ash pond and landfill closure costs; and a $78 million charge related to other items, partially offset by $60 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2015.

(d) Earnings for the twelve months ended December 31, 2014 include a $374 million charge related to North Anna nuclear power station and offshore wind facilities; a $284 million charge associated with our liability management effort, which is included in fixed charges; a $121 million accrued charge associated with ash pond and landfill closure costs; and a $93 million charge related to other items, partially offset by a $100 million net gain on the sale of our electric retail energy marketing business and $72 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2014.

(e) Earnings for the twelve months ended December 31, 2013 include a $55 million impairment charge related to certain natural gas infrastructure assets; a $40 million charge in connection with the Virginia State Corporation Commission's final ruling associated with its biennial review of Virginia Electric and Power Company's base rates for 2011-2012 test years; a $28 million charge associated with our operating expense reduction initiative, primarily reflecting severance pay and other employee related costs; a $26 million charge related to the expected early shutdown of certain coal-fired generating units; and a $29 million charge related to other items, partially offset by $81 million of net gain related to our investments in nuclear decommissioning trust funds; a $47 million benefit due to a downward revision in the nuclear decommissioning asset retirement obligations for certain merchant nuclear units that are no longer in service; and a $29 million net benefit primarily resulting from the sale of the Elwood power station. Excluding the net effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2013.

Exhibit 12.2

Virginia Electric and Power Company
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)
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	Years Ended December 31,				
	2017	2016	2015	2014	2013
Earnings, as defined:					
Income from continuing operations before income tax expense	$2,314	$1,945	$1,746	$1,406	$1,797
Fixed charges included in income	532	495	474	438	401
Total earnings, as defined	$2,846	$2,440	$2,220	$1,844	$2,198
Fixed charges, as defined:					
Interest charges	$ 513	$ 478	$ 457	$ 425	$ 388
Rental interest factor	19	17	17	13	13
Fixed charges included in income	$ 532	$ 495	$ 474	$ 438	$ 401
Capitalized interest	1	—	—	—	—
Total fixed charges, as defined	$ 533	$ 495	$ 474	$ 438	$ 401
Ratio of Earnings to Fixed Charges	**5.34**	**4.93**	**4.68**	**4.21**	**5.48**

Exhibit 12.3

Dominion Energy Gas Holdings, LLC
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)
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	Years Ended December 31,				
	2017	2016	2015	2014	2013
Earnings, as defined:					
Income from continuing operations before income tax expense	$ 666	$ 607	$ 740	$ 846	$ 762
Distributed income from unconsolidated investees, less equity in earnings	1	—	(3)	(1)	(2)
Fixed charges included in income	116	109	86	39	43
Total earnings, as defined	$ 783	$ 716	$ 823	$ 884	$ 803
Fixed charges, as defined:					
Interest charges	$ 106	$ 97	$ 74	$ 28	$ 30
Rental interest factor	10	12	12	11	13
Total fixed charges, as defined	$ 116	$ 109	$ 86	$ 39	$ 43
Ratio of Earnings to Fixed Charges	**6.75**	**6.57**	**9.57**	**22.67**	**18.67**

Exhibit 21

Dominion Energy, Inc.
Subsidiaries of the Registrant
As of February 15, 2018

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Name	Jurisdiction of Incorporation	Name Under Which Business is Conducted
Dominion Energy, Inc.	Virginia	Dominion Energy, Inc.
CNG Coal Company	Delaware	CNG Coal Company
Dominion ACP Holding, Inc.	Virginia	Dominion ACP Holding, Inc.
Dominion Atlantic Coast Pipeline, LLC	Virginia	Dominion Atlantic Coast Pipeline, LLC
Dominion Alternative Energy Holdings, Inc.	Virginia	Dominion Alternative Energy Holdings, Inc.
Dominion Energy Technologies, Inc.	Virginia	Dominion Energy Technologies, Inc.
Dominion Energy Technologies II, Inc.	Virginia	Dominion Energy Technologies II, Inc.
Dominion Voltage, Inc.	Virginia	Dominion Voltage, Inc.
		DVI
Tredegar Solar Fund I, LLC	Delaware	Tredegar Solar Fund I, LLC
Dominion Capital, Inc.	Virginia	Dominion Capital, Inc.
Dominion Cove Point, Inc.	Virginia	Dominion Cove Point, Inc.
Dominion Energy Midstream GP, LLC	Delaware	Dominion Energy Midstream GP, LLC
Dominion Energy Midstream Partners, LP	Delaware	Dominion Energy Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion Energy Carolina Gas Transmission, LLC	South Carolina	Dominion Energy Carolina Gas Transmission, LLC
Dominion Energy Questar Pipeline, LLC	Utah	Dominion Energy Questar Pipeline, LLC
Dominion Energy Overthrust Pipeline, LLC	Utah	Dominion Energy Overthrust Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Dominion Gas Projects Company, LLC	Delaware	Dominion Gas Projects Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion MLP Holding Company, LLC	Delaware	Dominion MLP Holding Company, LLC
Dominion Energy Midstream Partners, LP	Delaware	Dominion Energy Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion Energy Carolina Gas Transmission, LLC	South Carolina	Dominion Energy Carolina Gas Transmission, LLC
Dominion Energy Questar Pipeline, LLC	Utah	Dominion Energy Questar Pipeline, LLC
Dominion Energy Overthrust Pipeline, LLC	Utah	Dominion Energy Overthrust Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Dominion Energy Carolina Gas Services, Inc.	Virginia	Dominion Energy Carolina Gas Services, Inc.
Dominion Energy Field Services, Inc.	Delaware	Dominion Energy Field Services, Inc.
Dominion Energy Fuel Services, Inc.	Virginia	Dominion Energy Fuel Services, Inc.
Dominion Energy Gas Holdings, LLC	Virginia	Dominion Energy Gas Holdings, LLC
Dominion Energy Transmission, Inc.	Delaware	Dominion Energy Transmission, Inc.
Dominion Brine, LLC	Delaware	Dominion Brine, LLC
Tioga Properties, LLC	Delaware	Tioga Properties, LLC
Farmington Properties, Inc.	Pennsylvania	Farmington Properties, Inc.
NE Hub Partners, L.L.C.	Delaware	NE Hub Partners, L.L.C.

NE Hub Partners, L.P.	Delaware	NE Hub Partners, L.P.
Dominion Gathering & Processing, Inc.	Virginia	Dominion Gathering & Processing, Inc.
Dominion Iroquois, Inc.	Delaware	Dominion Iroquois, Inc.
The East Ohio Gas Company	Ohio	Dominion Energy Ohio
Dominion Energy Payroll Company, Inc.	Virginia	Dominion Energy Payroll Company, Inc.
Dominion Energy Questar Corporation	Utah	Dominion Energy Questar Corporation
Dominion Energy Questar Pipeline Services, Inc.	Utah	Dominion Energy Questar Pipeline Services, Inc.
Dominion Energy Wexpro Services Company	Utah	Dominion Energy Wexpro Services Company
QPC Holding Company	Utah	QPC Holding Company
Dominion Energy Midstream Partners, LP	Delaware	Dominion Energy Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion Energy Carolina Gas Transmission, LLC	South Carolina	Dominion Energy Carolina Gas Transmission, LLC
Dominion Energy Questar Pipeline, LLC	Utah	Dominion Energy Questar Pipeline, LLC
Dominion Energy Overthrust Pipeline, LLC	Utah	Dominion Energy Overthrust Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Questar InfoComm, Inc.	Utah	Questar InfoComm, Inc.
Questar Energy Services, Inc.	Utah	Questar Energy Services, Inc.
Questar Project Employee Company	Utah	Questar Project Employee Company
Questar Southern Trails Pipeline Company	Utah	Questar Southern Trails Pipeline Company
Questar Gas Company	Utah	Dominion Energy Utah (in Utah) Dominion Energy Wyoming (in Wyoming) Dominion Energy Idaho (in Idaho)
Wexpro Company	Utah	Dominion Energy Wexpro
Wexpro II Company	Utah	Wexpro II Company
Wexpro Development Company	Utah	Wexpro Development Company
Dominion Energy Services, Inc.	Virginia	Dominion Energy Services, Inc.
Dominion Energy Solutions, Inc.	Delaware	Dominion Energy Solutions Dominion East Ohio Energy Dominion Peoples Plus
Dominion Energy Technical Solutions, Inc.	Virginia	Dominion Energy Technical Solutions, Inc.
Dominion Generation, Inc.	Virginia	Dominion Generation, Inc.
CNG Power Services Corporation	Delaware	CNG Power Services Corporation
Dominion Bridgeport Fuel Cell, LLC	Virginia	Dominion Bridgeport Fuel Cell, LLC
Dominion Cogen WV, Inc.	Virginia	Dominion Cogen WV, Inc.
Dominion Energy Generation Marketing, Inc.	Delaware	Dominion Energy Generation Marketing, Inc.
Dominion Energy Nuclear Connecticut, Inc.	Delaware	Dominion Energy Nuclear Connecticut, Inc.
Dominion Energy Manchester Street, Inc.	Virginia	Dominion Energy Manchester Street, Inc.
Dominion Energy Solar CA, LLC	Delaware	Dominion Energy Solar CA, LLC
Dominion Energy Terminal Company, Inc.	Virginia	Dominion Energy Terminal Company, Inc.
Dominion Equipment, Inc.	Virginia	Dominion Equipment, Inc.
Dominion Equipment III, Inc.	Delaware	Dominion Equipment III, Inc.
Dominion Fairless Hills, Inc.	Delaware	Dominion Fairless Hills, Inc.
Dominion Energy Fairless, LLC	Delaware	Dominion Energy Fairless, LLC
Dominion Mt. Storm Wind, LLC	Virginia	Dominion Mt. Storm Wind, LLC
Dominion North Star Generation, Inc.	Delaware	Dominion North Star Generation, Inc.
North Star Generation, LLC	Delaware	North Star Generation, LLC
Dominion Nuclear Projects, Inc.	Virginia	Dominion Nuclear Projects, Inc.

Dominion Energy Kewaunee, Inc.	Wisconsin	Dominion Energy Kewaunee, Inc.
Dominion Person, Inc.	Delaware	Dominion Person, Inc.
Dominion Solar Projects III, Inc.	Virginia	Dominion Solar Projects III, Inc.
Four Brothers Solar, LLC	Delaware	Four Brothers Solar, LLC
Enterprise Solar, LLC	Delaware	Enterprise Solar, LLC
Escalante Solar I, LLC	Delaware	Escalante Solar I, LLC
Escalante Solar II, LLC	Delaware	Escalante Solar II, LLC
Escalante Solar III, LLC	Delaware	Escalante Solar III, LLC
Granite Mountain Holdings, LLC	Delaware	Granite Mountain Holdings, LLC
Granite Mountain Solar East, LLC	Delaware	Granite Mountain Solar East, LLC
Granite Mountain Solar West, LLC	Delaware	Granite Mountain Solar West, LLC
Iron Springs Holdings, LLC	Delaware	Iron Springs Holdings, LLC
Iron Springs Solar, LLC	Delaware	Iron Springs Solar, LLC
Dominion Solar Projects IV, Inc.	Virginia	Dominion Solar Projects IV, Inc.
Eastern Shore Solar LLC	Delaware	Eastern Shore Solar LLC
Hecate Energy Cherrydale LLC	Delaware	Hecate Energy Cherrydale LLC
Hecate Energy Clarke County LLC	Delaware	Hecate Energy Clarke County LLC
Southampton Solar LLC	Delaware	Southampton Solar LLC
Virginia Solar 2017 Projects LLC	Delaware	Virginia Solar 2017 Projects LLC
Buckingham Solar I LLC	Delaware	Buckingham Solar I LLC
Correctional Solar LLC	Delaware	Correctional Solar LLC
Sappony Solar LLC	Delaware	Sappony Solar LLC
Scott-II Solar LLC	Delaware	Scott-II Solar LLC
Dominion Solar Projects V, Inc.	Virginia	Dominion Solar Projects V, Inc.
Summit Farms Solar, LLC	North Carolina	Summit Farms Solar, LLC
Dominion Solar Projects C, Inc.	Virginia	Dominion Solar Projects C, Inc.
Dominion Solar Holdings IV, LLC	Virginia	Dominion Solar Holdings IV, LLC
96WI 8me LLC	Delaware	96WI 8me LLC
Clipperton Holdings LLC	North Carolina	Clipperton Holdings LLC
Fremont Farm, LLC	North Carolina	Fremont Farm, LLC
Innovative Solar 37, LLC	North Carolina	Innovative Solar 37, LLC
Moffett Solar 1, LLC	Delaware	Moffett Solar 1, LLC
Moorings Farm 2, LLC	North Carolina	Moorings Farm 2, LLC
Mustang Solar, LLC	North Carolina	Mustang Solar, LLC
Pikeville Farm, LLC	North Carolina	Pikeville Farm, LLC
Ridgeland Solar Farm I, LLC	Delaware	Ridgeland Solar Farm I, LLC
Wakefield Solar, LLC	North Carolina	Wakefield Solar, LLC
Dominion Solar Projects D, Inc.	Virginia	Dominion Solar Projects C, Inc.
Dominion Solar Holdings IV, LLC	Virginia	Dominion Solar Holdings IV, LLC
96WI 8me LLC	Delaware	96WI 8me LLC
Clipperton Holdings LLC	North Carolina	Clipperton Holdings LLC
Fremont Farm, LLC	North Carolina	Fremont Farm, LLC
Innovative Solar 37, LLC	North Carolina	Innovative Solar 37, LLC
Moffett Solar 1, LLC	Delaware	Moffett Solar 1, LLC
Moorings Farm 2, LLC	North Carolina	Moorings Farm 2, LLC
Mustang Solar, LLC	North Carolina	Mustang Solar, LLC
Pikeville Farm, LLC	North Carolina	Pikeville Farm, LLC
Ridgeland Solar Farm I, LLC	Delaware	Ridgeland Solar Farm I, LLC
Wakefield Solar, LLC	North Carolina	Wakefield Solar, LLC
Dominion Solar Services, Inc.	Virginia	Dominion Solar Services, Inc.

Dominion State Line, LLC	Delaware	Dominion State Line, LLC
Dominion Wholesale, Inc.	Virginia	Dominion Wholesale, Inc.
Dominion Wind Projects, Inc.	Virginia	Dominion Wind Projects, Inc.
Dominion Fowler Ridge Wind, LLC	Virginia	Dominion Fowler Ridge Wind, LLC
Dominion Wind Development, LLC	Virginia	Dominion Wind Development, LLC
Prairie Fork Wind Farm, LLC	Virginia	Prairie Fork Wind Farm, LLC
SBL Holdco, LLC	Virginia	SBL Holdco, LLC
Dominion Solar Projects I, Inc.	Virginia	Dominion Solar Projects I, Inc.
Dominion Solar Holdings III, LLC	Virginia	Dominion Solar Holdings III, LLC
Alamo Solar, LLC	California	Alamo Solar, LLC
Catalina Solar 2, LLC	Delaware	Catalina Solar 2, LLC
Cottonwood Solar, LLC	Delaware	Cottonwood Solar, LLC
Imperial Valley Solar Company (IVSC) 2, LLC	California	Imperial Valley Solar Company (IVSC) 2, LLC
Maricopa West Solar PV, LLC	Delaware	Maricopa West Solar PV, LLC
Pavant Solar LLC	Delaware	Pavant Solar LLC
Richland Solar Center, LLC	Georgia	Richland Solar Center, LLC
Dominion Solar Projects II, Inc.	Virginia	Dominion Solar Projects II, Inc.
Dominion Solar Holdings III, LLC	Virginia	Dominion Solar Holdings III, LLC
Alamo Solar, LLC	California	Alamo Solar, LLC
Catalina Solar 2, LLC	Delaware	Catalina Solar 2, LLC
Cottonwood Solar, LLC	Delaware	Cottonwood Solar, LLC
Imperial Valley Solar Company (IVSC) 2, LLC	California	Imperial Valley Solar Company (IVSC) 2, LLC
Maricopa West Solar PV, LLC	Delaware	Maricopa West Solar PV, LLC
Pavant Solar LLC	Delaware	Pavant Solar LLC
Richland Solar Center, LLC	Georgia	Richland Solar Center, LLC
Dominion Solar Projects A, Inc.	Virginia	Dominion Solar Projects A, Inc.
Dominion Solar Holdings I, LLC	Virginia	Dominion Solar Holdings I, LLC
Azalea Solar, LLC	Delaware	Azalea Solar, LLC
Dominion Solar Construction and Maintenance, LLC	Virginia	Dominion Solar Construction and Maintenance, LLC
Indy Solar Development, LLC	Delaware	Indy Solar Development, LLC
Indy Solar I, LLC	Delaware	Indy Solar I, LLC
Indy Solar II, LLC	Delaware	Indy Solar II, LLC
Indy Solar III, LLC	Delaware	Indy Solar III, LLC
Somers Solar Center, LLC	Delaware	Somers Solar Center, LLC
Dominion Solar Holdings II, LLC	Virginia	Dominion Solar Holdings II, LLC
CID Solar, LLC	Delaware	CID Solar, LLC
Dominion Solar Gen-Tie, LLC	Delaware	Dominion Solar Gen-Tie, LLC
Mulberry Farm, LLC	North Carolina	Mulberry Farm, LLC Mulberry Solar Farm, LLC
RE Adams East LLC	Delaware	RE Adams East LLC
RE Camelot LLC	Delaware	RE Camelot LLC
RE Columbia, LLC	Delaware	RE Columbia LLC
RE Columbia Two LLC	Delaware	RE Columbia Two LLC
RE Columbia, LLC	Delaware	RE Columbia LLC
RE Kansas LLC	Delaware	RE Kansas LLC
RE Kent South LLC	Delaware	RE Kent South LLC
RE Old River One LLC	Delaware	RE Old River One LLC
Selmer Farm, LLC	North Carolina	Selmer Farm, LLC
TA – Acacia, LLC	Delaware	TA – Acacia, LLC

		West Antelope Solar Park
Dominion Solar Projects B, Inc.	Virginia	Dominion Solar Projects B, Inc.
Dominion Solar Holdings I, LLC	Virginia	Dominion Solar Holdings I, LLC
Azalea Solar, LLC	Delaware	Azalea Solar, LLC
Dominion Solar Construction and Maintenance, LLC	Virginia	Dominion Solar Construction and Maintenance, LLC
Indy Solar Development, LLC	Delaware	Indy Solar Development, LLC
Indy Solar I, LLC	Delaware	Indy Solar I, LLC
Indy Solar II, LLC	Delaware	Indy Solar II, LLC
Indy Solar III, LLC	Delaware	Indy Solar III, LLC
Somers Solar Center, LLC	Delaware	Somers Solar Center, LLC
Dominion Solar Holdings II, LLC	Virginia	Dominion Solar Holdings II, LLC
CID Solar, LLC	Delaware	CID Solar, LLC
Dominion Solar Gen-Tie, LLC	Delaware	Dominion Solar Gen-Tie, LLC
Mulberry Farm, LLC	North Carolina	Mulberry Farm, LLC
		Mulberry Solar Farm, LLC
RE Adams East LLC	Delaware	RE Adams East LLC
RE Camelot LLC	Delaware	RE Camelot LLC
RE Columbia LLC	Delaware	RE Columbia LLC
RE Columbia Two LLC	Delaware	RE Columbia Two LLC
RE Columbia LLC	Delaware	RE Columbia LLC
RE Kansas LLC	Delaware	RE Kansas LLC
RE Kent South LLC	Delaware	RE Kent South LLC
RE Old River One LLC	Delaware	RE Old River One LLC
Selmer Farm, LLC	North Carolina	Selmer Farm, LLC
TA – Acacia, LLC	Delaware	TA – Acacia, LLC
		West Antelope Solar Park
Dominion Greenbrier, Inc.	Virginia	Dominion Greenbrier, Inc.
Greenbrier Pipeline Company, LLC	Delaware	Greenbrier Pipeline Company, LLC
Greenbrier Marketing Company, LLC	Delaware	Greenbrier Marketing Company, LLC
Dominion High Voltage Holdings, Inc.	Virginia	Dominion High Voltage Holdings, Inc.
Dominion High Voltage MidAtlantic, Inc.	Virginia	Dominion High Voltage MidAtlantic, Inc.
Dominion Investments, Inc.	Virginia	Dominion Investments, Inc.
Dominion Keystone Pipeline Holdings, Inc.	Delaware	Dominion Keystone Pipeline Holdings, Inc.
Dominion Keystone Pipeline, LLC	Delaware	Dominion Keystone Pipeline, LLC
Dominion MLP Holding Company II, Inc.	Virginia	Dominion MLP Holding Company II, Inc.
Dominion MLP Holding Company III, Inc.	Virginia	Dominion MLP Holding Company III, Inc.
Dominion Modular LNG Holdings, Inc.	Virginia	Dominion Modular LNG Holdings, Inc.
Niche LNG, LLC	Delaware	Niche LNG, LLC
Dominion Natrium Holdings, Inc.	Delaware	Dominion Natrium Holdings, Inc.
Dominion Oklahoma Texas Exploration & Production, Inc.	Delaware	Dominion Oklahoma Texas Exploration & Production, Inc.
Dominion Privatization Holdings, Inc.	Virginia	Dominion Privatization Holdings, Inc.
Dominion Privatization Florida, LLC	Virginia	Dominion Privatization Florida, LLC
Dominion Privatization Georgia, LLC	Virginia	Dominion Privatization Georgia, LLC
Dominion Privatization Kentucky, LLC	Virginia	Dominion Privatization Kentucky, LLC
Dominion Privatization South Carolina, LLC	Virginia	Dominion Privatization South Carolina, LLC
Dominion Privatization Texas, LLC	Virginia	Dominion Privatization Texas, LLC
Dominion Products and Services, Inc.	Delaware	Dominion Products and Services, Inc.
		Dominion Energy Solutions

Dominion Projects Services, Inc.	Virginia	Dominion Projects Services, Inc.
Dominion Resources Capital Trust III	Delaware	Dominion Resources Capital Trust III
Dominion South Holdings I, Inc.	Delaware	Dominion South Holdings I, Inc.
Dominion South Holdings II, LLC	Delaware	Dominion South Holdings II, LLC
Dominion South Pipeline Company, LP	Delaware	Dominion South Pipeline Company, LP
Hope Gas, Inc.	West Virginia	Dominion Energy West Virginia
Sedona Corp.	South Carolina	Sedona Corp.
Virginia Electric and Power Company	Virginia	Dominion Energy Virginia (in Virginia) Dominion Energy North Carolina (in North Carolina)
Virginia Power Fuel Corporation	Virginia	Virginia Power Fuel Corporation
Virginia Power Services, LLC	Virginia	Virginia Power Services, LLC
Virginia Power Nuclear Services Company	Virginia	Virginia Power Nuclear Services Company
Virginia Power Services Energy Corp., Inc.	Virginia	Virginia Power Services Energy Corp., Inc.
VP Property, Inc.	Virginia	VP Property, Inc.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-216476, 333-219088 and 333-221291 on Form S-3, Registration Statement No. 333-223036 on Form S-4, and Registration Statement Nos. 033-62705, 333-02733, 333-09167, 333-18391, 333-25587, 333-49725, 333-78173, 333-85094, 333-87529, 333-95795, 333-110332, 333-124256, 333-124257, 333-130566, 333-130570, 333-143916, 333-149989, 333-149993, 333-156027, 333-163805, 333-189578, 333-189579, 333-189580, 333-189581, 333-195768, 333-202364, 333-202366 and 333-203952 on Form S-8 of our reports dated February 27, 2018, relating to the consolidated financial statements of Dominion Energy, Inc. and subsidiaries and the effectiveness of Dominion Energy, Inc. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Dominion Energy, Inc. for the year ended December 31, 2017.

We consent to the incorporation by reference in Registration Statement No. 333-219085 on Form S-3 of our report dated February 27, 2018, relating to the consolidated financial statements of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries, appearing in this Annual Report on Form 10-K of Virginia Electric and Power Company for the year ended December 31, 2017.

We consent to the incorporation by reference in Registration Statement No. 333-219086 on Form S-3 of our report dated February 27, 2018, relating to the consolidated financial statements of Dominion Energy Gas Holdings, LLC (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries, appearing in this Annual Report on Form 10-K of Dominion Energy Gas Holdings, LLC for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

Exhibit 31.a

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this report on Form 10-K of Dominion Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
President and Chief Executive Officer

Exhibit 31.b

I, Mark F. McGettrick, certify that:

T

1. I have reviewed this report on Form 10-K of Dominion Energy, Inc.;

T

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

T

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

T

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

T

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

T

Date: February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer

Exhibit 31.c

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
Chief Executive Officer

Exhibit 31.d

I, Mark F. McGettrick, certify that:

1. I have reviewed this report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and
Chief Financial Officer

Exhibit 31.e

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this report on Form 10-K of Dominion Energy Gas Holdings, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer

Exhibit 31.f

I, Mark F. McGettrick, certify that:

T

1. I have reviewed this report on Form 10-K of Dominion Energy Gas Holdings, LLC;

T

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

T

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

T

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

T

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

T

Date: February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer

Exhibit 32.a

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Dominion Energy, Inc. (the "Company"), certify that:

T

1. the Annual Report on Form 10-K for the year ended December 31, 2017 (the "Report"), of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

T

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2017, and for the period then ended.

T

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
President and Chief Executive Officer
February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 27, 2018

Exhibit 32.b

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Virginia Electric and Power Company (the “Company”), certify that:

T

1. the Annual Report on Form 10-K for the year ended December 31, 2017 (the “Report”), of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

T

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2017, and for the period then ended.

T

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer
February 27, 2018

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 27, 2018

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Dominion Energy Gas Holdings, LLC (the “Company”), certify that:

1. the Annual Report on Form 10-K for the year ended December 31, 2017 (the “Report”), of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2017, and for the period then ended.

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer
February 27, 2018

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 27, 2018

FORM DEF 14A

SCANA CORP - SCG

Filed: March 24, 2017 (period: April 27, 2017)

Official notification to shareholders of matters to be brought to a vote (Proxy)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SCHEDULE 14A INFORMATION

Proxy Statement Pursuant to Section 14(a) of the
Securities Exchange Act of 1934
(Amendment No.)

Filed by the Registrant ☒ Filed by a Party other than the Registrant ☐

Check the appropriate box:

☐ Preliminary Proxy Statement

☐ **Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**

☒ Definitive Proxy Statement

☐ Definitive Additional Materials

☐ Soliciting Material under Rule 14a-12

SCANA CORPORATION
(Name of Registrant as Specified In Its Charter)

(Name of person(s) filing proxy statement, if other than the registrant)

Payment of Filing Fee (Check the appropriate box):

☒ No fee required.

☐ Fee computed on table below per Exchange Act Rules 14a-6(i)(4) and 0-11.

(1) Title of each class of securities to which transaction applies:

(2) Aggregate number of securities to which transaction applies:

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

(4) Proposed maximum aggregate value of transaction:

(5) Total fee paid:

☐ Fee paid previously with preliminary materials.

☐ Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

(4) Date Filed:

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SCANA Corporation
2017 Proxy Materials

Chairman's Letter and 2016 Highlights • Notice of Annual Meeting • Proxy Statement for Annual Meeting
Annual Financial Statements • Management's Discussion and Analysis • Related Annual Report Information

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March 24, 2017

Dear Shareholders:

You are cordially invited to attend the 2017 Annual Meeting of Shareholders to be held at 9:00 a.m., Eastern Daylight Time, on Thursday, April 27, 2017. The meeting will be held at Leaside, 100 East Exchange Place, Columbia, South Carolina 29209. Directions are on the back of the admission ticket and on page 67 of this Proxy Statement. An admission ticket is required and is enclosed as part of your proxy card if you were a shareholder of record on the record date, March 1, 2017. If you hold your shares through a broker or other nominee, you must provide proof of ownership on the record date in order to attend the meeting.

At our 2017 Annual Meeting of Shareholders I will provide a brief report on SCANA's 2016 business results. I welcome the opportunity to discuss some of our accomplishments during 2016, as well as some of our challenges for 2017 and beyond. I hope you will be able to join us at our Annual Meeting, but for those of you who will be unable to attend, I would like to highlight some of our most significant accomplishments over the last year, which include:

- We continued to move forward and make substantial progress on initiatives important to our Company.
- We exceeded our 2016 total shareholder return target by ranking in the top 25% of our peer group of utilities.
- We raised our quarterly cash dividend on the Company's common stock in February 2017 to 61¼ cents per share, from 57½ cents per share, an increase of 6.5%.

Our 2017 Proxy Statement includes a Board proposal for the declassification of our Board of Directors. Our Board is committed to strong corporate governance practices. In considering the prior shareholder proposals we have received, as well as the support of institutional investor groups for the annual election of directors, the Board has decided to once again propose an amendment to our Articles of Incorporation to declassify our Board of Directors and to submit it to our shareholders.

Enclosed are the Notice of Annual Meeting identifying the five proposals that will be presented at the meeting, and SCANA's Proxy Statement and form of proxy for the meeting. We are including SCANA's annual consolidated financial statements, management's discussion and analysis of financial condition and results of operations and related annual report information as an appendix to the Proxy Statement.

Your vote is important. We encourage you to read the Proxy Statement and vote your shares as soon as possible. Please vote today either by telephone or Internet, or by signing, dating and mailing your proxy card or broker's or other nominee's voting instruction form in the envelope enclosed. Telephone and Internet voting permits you to vote at your convenience, 24 hours a day, seven days a week. Detailed voting instructions are included on the back of your proxy card or broker's or other nominee's voting instruction form.

Sincerely,

Kevin B. Marsh
Chairman of the Board
President and Chief Executive Officer

NOTICE OF ANNUAL MEETING

Meeting Date:	Thursday, April 27, 2017
Meeting Time:	9:00 a.m., Eastern Daylight Time
Meeting Place:	Leaside 100 East Exchange Place Columbia, South Carolina 29209
Meeting Record Date:	March 1, 2017
Meeting Agenda:	1) Election of three Class III Directors 2) Advisory (non-binding) vote on executive compensation 3) Advisory (non-binding) vote on the frequency of the executive compensation vote 4) Approval of the appointment of the independent registered public accounting firm 5) Approval of Board-proposed amendments to Article 8 of our Articles of Incorporation to declassify the Board of Directors and provide for the annual election of all directors

Shareholder List

Upon written request by a shareholder, a list of shareholders entitled to vote at the meeting will be available for inspection at SCANA's Corporate Headquarters, 100 SCANA Parkway, Cayce, South Carolina 29033, during business hours from March 17, 2017 through the date of the meeting.

Admission to the Meeting

An admission ticket or proof of share ownership as of the record date is required. If you plan to use the admission ticket, please remember to detach the admission ticket from your proxy card before mailing your proxy card. If you hold your shares through a broker or other nominee, you must provide proof of ownership by bringing either a copy of the voting instruction card provided by your broker or other nominee or a brokerage statement showing your share ownership as of March 1, 2017. Audio or visual recording, and related equipment, is strictly prohibited without SCANA's prior written approval.

Meeting Attendance

If you vote by mail and plan to attend the meeting, please indicate your intention to do so on your proxy card. If you vote by telephone or Internet, please follow the instructions to indicate that you plan to attend the 2017 Annual Meeting. If you require handicap assistance to attend the meeting, please contact the Office of the Corporate Secretary, at 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033, or call 803-217-7568 no later than Thursday, April 20, 2017.

By Order of the Board of Directors,

Gina Champion
Vice President
Corporate Secretary
Deputy General Counsel

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SCANA Corporation
100 SCANA Parkway
Cayce, South Carolina 29033

PROXY STATEMENT

PROXY STATEMENT SUMMARY

This summary highlights information discussed in more detail elsewhere in this proxy statement, and does not include all the information you should consider in deciding how to vote. You should read the entire proxy statement carefully before voting. Page references are provided to help you locate the information in this proxy statement. These proxy materials are first being mailed to shareholders on or about March 24, 2017.

Annual Meeting of Shareholders

Date and Time:	Thursday, April 27, 2017, 9:00 a.m. Eastern Daylight Time
Place:	Leaside, 100 East Exchange Place, Columbia, South Carolina 29209
Record Date:	You can vote if you were a shareholder of record on March 1, 2017.
Admission:	You will need an admission ticket or proof of share ownership on the record date, March 1, 2017, to attend the meeting.

Matters to be Voted on and Board Recommendations

Proposal 1 *— Election of the following three Class III Directors, each to serve a three year term (page 8):*

- *John F.A.V. Cecil*
- *D. Maybank Hagood*
- *Alfredo Trujillo*

Proposal 2 *— Advisory (non-binding) vote to approve executive compensation (page 60)*

Proposal 3 *— Advisory (non-binding) vote on the frequency of the executive compensation vote (page 61)*

Proposal 4 *— Approval of the appointment of the independent registered public accounting firm (page 63)*

Proposal 5 *— Approval of Board-proposed amendments to Article 8 of our Articles of Incorporation to declassify the Board of Directors and provide for the annual election of all directors (page 64)*

The Board of Directors recommends a vote FOR all of the Director Nominees, FOR Proposal 2, FOR One Year on Proposal 3, and FOR Proposals 4 and 5.

How to Cast Your Vote

You can vote by any of the following methods:

By Internet

See your proxy card for voting instructions

By Telephone

See your proxy card for voting instructions

By Mail

Mark the enclosed proxy card, sign, date and mail it in the enclosed postage-paid envelope (remember to detach and save your admission ticket before mailing the proxy card)

Your Vote is Important

Whether or not you plan to attend the Annual Meeting, please vote your shares as soon as possible.

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Nominees For Directors

Name	Age	Director Since	Professional Background	Independent	Committee Memberships
John F.A.V. Cecil	60	2013	President, Biltmore Farms, LLC	YES	Audit, Compensation
D. Maybank Hagood	55	1999	Chairman and Chief Executive Officer, Southern Diversified Distributors, Inc.; Chief Executive Officer, William M. Bird and Company, Inc.	YES	Executive, Nominating and Governance, Nuclear Oversight
Alfredo Trujillo	57	2013	President and Chief Operating Officer, The Georgia Tech Foundation	YES	Nominating and Governance, Nuclear Oversight

Business Highlights

As mentioned in our Chairman’s letter, some of our business highlights are as follow:

- We exceeded our 2016 total shareholder return target by ranking in the top 25% of our peer group of utilities.
- We raised our quarterly cash dividend on the Company’s common stock in February 2017 to 61¼ cents per share, from 57½ cents per share, an increase of 6.5%.

Governance Highlights

We are committed to high standards of corporate governance and our Governance Principles are intended to promote the long-term success of our Company. Some highlights of our corporate governance practices are listed below.

Number of Independent Directors	10 of 11
Audit, Nominating and Governance and Compensation Committees Comprised Entirely of Independent Directors	YES
Lead Independent Director	YES
Resignation Requirement if Director in Uncontested Election Receives More Voting Instructions Designated as “Withheld” Than as “For”	YES
Annual Board and Committee Self-Evaluations	YES
Stock Ownership Guidelines for Directors and Executive Officers	YES
Policy Prohibiting Hedging, Margining and Pledging of Company Stock by Directors, Executive Officers, Employees and Related Persons	YES
Shareholder Proxy Access Bylaw	YES

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QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING

Why am I receiving these proxy materials?

You are receiving these proxy materials in connection with the solicitation by the Board of Directors of SCANA Corporation (“SCANA,” the “Company,” “we” or “us”), a South Carolina corporation, of proxies to be voted at our 2017 Annual Meeting of Shareholders (the “Annual Meeting”), which will be held at 9:00 a.m., Eastern Daylight Time on Thursday, April 27, 2017, and at any adjournment or postponement of the meeting. The meeting will be held at Leaside, 100 East Exchange Place, Columbia, South Carolina 29209.

On what am I being asked to vote and what are the Board of Directors’ recommendations?

The following table lists the proposals scheduled to be voted on and the vote required for approval of each proposal:

Proposal	Board Recommendation	Vote	Abstentions	Broker Non-Votes	Unmarked Proxy Cards	Beginning on Page
Election of Directors ***(Proposal 1)***	For All Nominees	Plurality	No effect	No effect	Will be voted “FOR”	8
Advisory (non-binding) vote to approve executive compensation ***(Proposal 2)***	For	More votes for than against*	No effect	No effect	Will be voted “FOR”	60
Advisory (non-binding) vote on the frequency of the executive compensation vote ***(Proposal 3)***	One Year	Frequency receiving greatest number of votes*	No effect	No effect	Will be voted for One Year	61
Approval of Appointment of Deloitte & Touche LLP as Independent Registered Public Accounting Firm ***(Proposal 4)***	For	More votes for than against	No effect	No effect	Will be voted “FOR”	63
Approval of Board-proposed amendments to Article 8 of our Articles of Incorporation to declassify the Board of Directors and provide for the annual election of all directors ***(Proposal 5)***	For	80% of all outstanding shares	Against	Against	Will be voted “FOR”	64

* These votes are advisory and the results are not binding on the Board of Directors or the Company.

Who may vote?

You will only be entitled to vote at the Annual Meeting if our records show that you were a shareholder of record on March 1, 2017, the record date, or if you hold your shares in street name, you present proof of ownership and appropriate voting documents from the record shareholder.

How do I vote shares that I hold directly in my name?

If you hold your shares directly, you may vote by proxy or in person at the meeting. To vote by proxy, you may select one of the following options: telephone, Internet or mail.

Vote by Telephone:

You may vote your shares by telephone using the toll-free number shown on your proxy card. Telephone voting is available 24 hours a day, seven days a week. Clear and simple voice prompts allow you to vote your shares and confirm that your instructions have been properly recorded. If you vote by telephone, please **DO NOT** return your proxy card.

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Vote by Internet:

You may vote your shares by Internet. The website for Internet voting is shown on your proxy card. Internet voting is available 24 hours a day, seven days a week. When you vote by Internet, you will be given the opportunity to confirm that your instructions have been properly recorded. If you vote by Internet, please **DO NOT** return your proxy card.

Vote by Mail:

If you choose to vote by mail, please mark the enclosed proxy card, date and sign it, detach your meeting admission ticket, and return your proxy card in the enclosed postage-paid envelope.

If I hold my shares directly, what actions will the proxies take?

If you hold your shares directly and indicate your voting choices on your proxy card, the persons identified as proxies on the accompanying proxy card will vote your shares according to your instructions. If your proxy card is signed and returned without specifying choices, the proxies intend to vote your shares FOR all of the Board of Director nominees; FOR Proposal 2 relating to approval of executive compensation; FOR one year on Proposal 3 relating to the frequency of the vote on executive compensation; FOR Proposal 4 relating to approval of the appointment of Deloitte & Touche LLP as the independent registered public accounting firm for 2017; and FOR Proposal 5 relating to the Board-proposed amendments to Article 8 of our Articles of Incorporation to declassify the Board of Directors and provide for the annual election of all directors.

The Board knows of no other matters to be presented for shareholder action at the Annual Meeting. If other matters are properly brought before the Annual Meeting, the persons identified as proxies on the accompanying proxy card intend to vote the shares represented by proxies in accordance with their best judgment.

How do I direct the vote of shares I hold in street name?

If you hold shares in street name, you may direct your vote by submitting your voting instructions to your broker or nominee. Please refer to the voting instructions provided by your broker or nominee. If you hold your shares in street name, the broker or nominee is permitted to vote your shares on Proposal 4, the approval of the appointment of Deloitte & Touche, LLP as our independent registered public accounting firm, even if the broker or nominee does not receive voting instructions from you. **However, a broker or nominee is *not* permitted to vote your shares on the election of directors or on Proposals 2, 3, or 5 unless you provide voting instructions.** Accordingly, if you do not return a broker or nominee voting instruction card, or if you return a broker or nominee voting instruction card that does not indicate how you want your broker or nominee to vote on election of directors or on Proposals 2, 3 or 5, a broker "non-vote" will occur as to those matters. A broker "non-vote" occurs when a nominee holding shares for a beneficial owner does not vote on a particular proposal because the nominee has not received instructions from the beneficial owner and either (i) does not have discretionary voting power for that particular proposal, or (ii) chooses not to vote the shares. **Therefore, it is very important that you provide your broker or nominee with voting instructions if your shares are held in street name.**

How do I vote shares I hold as a participant in the SCANA Corporation 401(k) Retirement Savings Plan (formerly named the SCANA Corporation Stock Purchase-Savings Plan)?

If you own shares of SCANA common stock as a participant in the SCANA Corporation 401(k) Retirement Savings Plan (formerly named the SCANA Corporation Stock Purchase-Savings Plan), you will receive a proxy card that covers only your Plan shares. Proxies executed by Plan participants will serve as instructions to the Plan's trustee as to how Plan shares are to be voted. If you do not instruct the Plan's trustee how your Plan shares are to be voted, the Plan trustee will instruct the proxy agents to vote your shares proportionally to the Plan shares voted. As a result of this proportional voting, if voting instructions are given for only a small percentage of participant shares, the wishes of those participants would determine the voting instructions by the Plan's trustee. Accordingly, the greater the number of participant shares for which participants complete and execute proxies, the more representative the Plan trustee's voting instructions will be.

May I change or revoke my proxy instructions?

Yes, you may change or revoke your proxy instructions at any time prior to the vote at the Annual Meeting. If you hold your shares directly in your name, you may accomplish this by granting a new proxy (by telephone, Internet or mail) bearing a later date (which automatically revokes the earlier proxy) or by attending the Annual Meeting and voting in

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person. Attendance at the meeting will not cause your previously granted proxy to be revoked unless you specifically so request. If you hold your shares in street name, you may change or revoke your proxy instructions by properly submitting new voting instructions to your broker or nominee.

May I vote in person at the Annual Meeting?

The method by which you vote will not limit your right to vote at the Annual Meeting if you decide to attend in person. However, if you wish to vote at the meeting and your shares are held in the name of a broker or other nominee of record, you must obtain a proxy executed in your favor from the holder of record prior to the meeting. Directions to the location of the Annual Meeting are on the back of the proxy card included with this mailing and on page 67.

What constitutes a quorum?

At the close of business on the record date, March 1, 2017, there were 142,916,917 shares of SCANA common stock outstanding and entitled to vote at the Annual Meeting. Each share is entitled to one vote on each proposal.

The presence, in person or by proxy, of the holders of a majority of the shares entitled to vote at the Annual Meeting is necessary to constitute a quorum. Abstentions, "withheld" votes and broker "non-votes" are counted as present and entitled to vote for purposes of determining a quorum.

What vote is needed to approve the matters submitted?

Proposal 1 — Election of Directors

The affirmative vote of a plurality of the votes cast is required for the election of directors. However, service on the Board following an uncontested election of directors is subject to the Board of Directors' policy regarding resignations by directors for whom more voting instructions received by the Company withhold authority to vote than grant authority to vote "For" the director. (See "Governance Information – Majority Withheld Director Resignation Policy.") "Plurality" means that if there were more nominees than positions to be filled, the individuals who received the largest number of votes cast for directors would be elected as directors. Because there are the same number of nominees as positions to be filled, we expect all nominees to be elected. Votes indicated as "withheld" and broker "non-votes" will not be deemed cast for nominees and will have no effect on the outcome of the election. If you hold your shares in street name and fail to instruct your broker or nominee how to vote, a broker "non-vote" on election of directors will occur with respect to your shares.

The Board knows of no reason why any of the nominees for director named herein would at the time of election be unable to serve. In the event, however, that any nominee named should, prior to the election, become unable to serve as a director, your proxy will be voted for such other person or persons as the Board may recommend.

Proposal 2 — Advisory (non-binding) Vote to Approve Executive Compensation

This proposal will be approved if more shares vote in favor of the proposal than against. However, this proposal is advisory and non-binding on us and on our Board of Directors. Marking the proxy card or your broker voting instructions "FOR" indicates support; marking the proxy card or your broker voting instructions "Against" indicates lack of support. You may also abstain by marking the "Abstain" box on the proxy card or your broker voting instructions. If you hold your shares in street name and fail to instruct your broker how to vote, a broker "non-vote" will occur with respect to your shares. Abstentions and broker non-votes will have no effect on the outcome.

Proposal 3 — Advisory (non-binding) Vote on the Frequency of the Executive Compensation Vote

The frequency that receives the largest number of votes will be approved. However, this proposal is advisory and non-binding on us and on our Board of Directors. You have four choices with respect to the vote on the frequency of future advisory votes to approve executive compensation: one year; or two years; or three years; or abstain. If you hold your shares in street name and fail to instruct your broker how to vote, a broker non-vote will occur with respect to your shares. Abstentions and broker non-votes will have no effect on the outcome.

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Proposal 4 — Approval of the Appointment of Deloitte & Touche LLP as the Independent Registered Public Accounting Firm for 2017

The appointment of Deloitte & Touche LLP as our independent registered public accounting firm will be approved if more shares are voted for approval than are voted against. Accordingly, abstentions and broker “non-votes” will have no effect on the results. If you hold your shares in street name and fail to instruct your broker or nominee how to vote, your broker or nominee will, nonetheless, have discretionary authority to vote your shares if it chooses to do so.

Proposal 5 — Approval of Board-Proposed Amendments to Article 8 of our Articles of Incorporation to Declassify the Board of Directors and Provide for the Annual Election of All Directors

The proposal to amend our Articles of Incorporation to declassify the Board of Directors and provide for the annual election of all directors requires the affirmative vote of at least 80% of all outstanding shares of our common stock. Votes indicated as “abstain” and broker “non-votes” will have the effect of votes against the proposal. If you hold your shares in street name and fail to instruct your broker or nominee how to vote, a broker “non-vote” will occur with respect to your shares.

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QUESTIONS AND ANSWERS ABOUT EXECUTIVE COMPENSATION

Have Any Changes Been Made to Short-Term and Long-Term Incentive Compensation Practices Since the Last Shareholder Advisory Vote on Executive Compensation?

Yes. As discussed in the Company's 2015 and 2016 Proxy Statements, in response to comments from proxy advisory firms, and taking into account the results of the 2014 shareholder advisory vote, in late 2014 and early 2015, our Compensation Committee reviewed and recommended to the Board a number of changes for the executive compensation awards to be granted in 2015 from the awards granted over the past several years. The Company's Compensation Consultant, Willis Towers Watson, advised management that these changes would bring our practices more in line with our peers' and current market practices.

These changes, which were implemented in 2015, included revising short-term annual incentive awards to equalize weighting of earnings per share goals and individual and business unit goals and to reduce the amount of discretionary award that can be paid, and revising long-term equity compensation awards to change the measurement of the performance cycles, increase the maximum payout, and change the mix of performance shares and restricted stock units, and are summarized below.

Short-Term Annual Incentive Compensation	Previous Awards (Prior to 2015)	2015 and 2016 Awards
Plan Weightings	25% of the annual cash incentive award was earned based on the extent to which we met designated earnings per share goals; and 75% of the cash incentive award was earned based on our Named Executive Officers and the other participants achieving individual and business performance objectives. The Compensation Committee reviewed and approved all senior executive officer individual and business objectives.	50% of the annual cash incentive award is earned based on the extent to which we meet designated earnings per share goals; and 50% of the award is earned based on our Named Executive Officers and the other participants achieving individual and business performance objectives. The Compensation Committee will continue to review and approve all senior executive officer individual and business objectives.
Discretionary Awards Above Target	Each year management could recommend to the Compensation Committee an additional discretionary payout of up to 20%, and the Board could award an additional 30% above that amount, for a potential total payout of up to 150% of target.	Payouts up to 130% of target awards based solely on the earnings per share goals are formulaic and not subject to discretion. The Board has the discretion to award up to an additional 20% above that amount, for a total potential payout of up to 150% of target.
Long-Term Equity Compensation	**Previous Awards (Prior to 2015)**	**2015 and 2016 Awards**
Plan Cycles	Performance measurement and award determinations for the performance shares for the three year periods were made on an annual basis with vesting and payment of awards being deferred until after the end of the three-year period.	Performance measurement and award determinations for the performance shares for the three year periods are made for the entire three-year cycle with vesting and payment of awards after the end of the three-year cycle.
Maximum Payout	For each of the Total Shareholder Return and earnings per share growth components, the maximum payout was 175% of target.	For each of the Total Shareholder Return and earnings per share growth components, the maximum payout is 200% of target.
Mix of Performance Shares and Restricted Stock Units	Annual grants were comprised of a mix of 80% performance shares and 20% restricted stock units.	Annual grants are comprised of a mix of 70% performance shares and 30% restricted stock units.

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INFORMATION ABOUT EXPERIENCE AND QUALIFICATION OF DIRECTORS AND NOMINEES

We believe the combined business and professional experience of our Directors, and their various areas of expertise, make them a useful resource to management and qualify them for service on our Board. Many of our Directors, including Ms. Miller and Messrs. Bennett, Hagood, and Sloan, have served on our Board for over fifteen years. During their tenures, they have gained considerable institutional knowledge about our Company, its operations, and its various regulators, which has made them effective Directors. Because our Company's operations and business structure are extremely complex and highly regulated, continuity of service and the development and retention of institutional knowledge help make our Board more efficient and effective at advising us regarding our long-range plans than would be the case if there were frequent turnover in Board membership. Nonetheless, we also believe it is important to have varying degrees of tenure on our Board, and we currently have three Directors with less than five years' experience serving on our Board. We believe a wide range of tenure, and periodically bringing new members onto the Board, allows our Board the opportunity to consider new ideas and processes while the experience of our more tenured Directors offers specific, historical perspectives on our strengths and weaknesses.

In addition to their other qualifications, six of our directors, Ms. Miller and Mrs. Decker and Messrs. Cecil, Hagood, Roquemore and Sloan, are, or were prior to retirement, business owners with financial and operational experience on all levels of their businesses. Each of these Directors brings a unique perspective to our Board. In addition, five of our directors, Ms. Miller and Messrs. Bennett, Marsh, Roquemore and Sloan, are, or have been, directors or executive officers of banks and/or bank holding companies. This service has provided them with meaningful experience in another highly regulated industry, which provides them with valuable instincts and insights that can be translated to our industry.

When Directors reach mandatory retirement age or otherwise leave our Board, we seek replacements who we believe will make significant contributions to our Board for a variety of reasons, including among others, business and financial experience and expertise, business and government contacts, relationship skills and industry knowledge. We also continually seek diversity on our Board, including diversity in skill sets, racial and cultural backgrounds, gender, and personal and business experiences.

Independent Director Recruiting

In 2012, the Nominating and Governance Committee directed management to retain an independent executive recruiting firm to assist the Committee in identifying and evaluating potential director candidates who meet the Director Qualification Criteria discussed on page 19. Since 2014, the Nominating and Governance Committee has considered certain candidates known to management and the Board, but has not formally engaged in recruiting activities with the independent executive recruiting firm in order to consider the candidates known to the Board. No new members were added to our Board in 2016.

PROPOSAL 1 — ELECTION OF DIRECTORS

Effective at the Annual Meeting, the Board has set the number of Directors at ten. The Board is divided into three classes with the members of each class usually serving a three-year term. The terms of the Class III Directors will expire at the Annual Meeting. The Board has decided to nominate the existing Class III Directors, Messrs. Cecil, Hagood and Trujillo, for reelection at the Annual Meeting of Shareholders to serve until the 2020 Annual Meeting of Shareholders, or until their successors are elected and qualified to serve.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR ALL" OF ITS DIRECTOR NOMINEES.

Information about Directors and Nominees

The information set forth on the following pages about the nominees and continuing directors has been furnished to us by such persons. Each of the Directors is also a Director of our subsidiary, South Carolina Electric & Gas Company. There are no family relationships among any of our Directors, Director nominees or executive officers.

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NOMINEES FOR DIRECTOR

Class III Directors – Terms to Expire at the Annual Meeting in 2020

John F.A.V. Cecil

President, Biltmore Farms, LLC

Director since 2013
Age 60

Biographical Information

Mr. Cecil has served as President of Biltmore Farms, LLC, a fourth generation family-owned business with a primary focus on sustainable community development, including home building, residential communities, apartments, hotels, and retail properties since 1992. He currently serves on Wells Fargo Bank, N.A.'s Western North Carolina Regional Advisory Board, as well as on other community and non-profit boards throughout North Carolina.

Experience and Qualifications

Mr. Cecil has decades of business experience within our service territory. In addition to his business expertise, he has leadership-level experience with many community-related endeavors, and has also served on community and private boards within our service territory for many years. As President of Biltmore Farms, LLC, Mr. Cecil brings to the Board the perspective of a private business owner, as well as the environmental perspective of the owner of a business that seeks to balance sustainability and business growth, both of which we believe are important to our customers and our strategic initiatives.

D. Maybank Hagood

Chairman and Chief Executive Officer, Southern Diversified Distributors, Inc.; Chief Executive Officer, William M. Bird and Company, Inc.

Director since 1999
Age 55

Biographical Information

Mr. Hagood has been Chief Executive Officer of Southern Diversified Distributors, Inc., located in Charleston, South Carolina, since 2003, and its Chairman since 2012. Southern Diversified Distributors, Inc. is the parent company of William M. Bird and Company, Inc., Southern Tile Distributors, LLC and TranSouth Logistics, LLC, providers of logistic, distribution and flooring distribution services. Mr. Hagood has also been Chief Executive Officer of William M. Bird and Company, Inc., a wholesale distributor of floor covering materials, in Charleston, South Carolina, since 1993. He previously served as President of William M. Bird and Company, Inc., until June 2009.

Experience and Qualifications

Mr. Hagood resides in our Charleston, South Carolina service territory, and brings significant community presence and business development experience to our Board. Mr. Hagood is particularly experienced in economic, environmental, and business development issues facing the manufacturing and building construction industries generally, and specifically the issues faced by manufacturers in our state.

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NOMINEES FOR DIRECTOR

Class III Directors – Terms to Expire at the Annual Meeting in 2020

Alfredo Trujillo

President and Chief Operating Officer, The Georgia Tech Foundation

Director since 2013
Age 57

Biographical Information

Mr. Trujillo was appointed President and Chief Operating Officer of The Georgia Tech Foundation in July 2013. He has also served as a self-employed investment fund advisor since 2007. Prior to 2007, Mr. Trujillo served as President and Chief Executive Officer of Recall Corporation, a global information management company. Since 2003, Mr. Trujillo has served on the board of directors of Haverty Furniture Companies, Inc.

Experience and Qualifications

Mr. Trujillo has domestic and international business expertise in areas as diverse as aerospace engineering, document management, and academic leadership. Additionally, Mr. Trujillo's service on the board of directors of another public company provides him with relevant board experience and perspectives on other public company best practices.

CONTINUING DIRECTORS

Class I Directors — Terms to Expire at the Annual Meeting in 2018

James A. Bennett

South Carolina Central Area Executive, First-Citizens Bank & Trust Company

Director since 1997
Age 56

Biographical Information

Mr. Bennett has been South Carolina Central Area Executive for First-Citizens Bank & Trust Company in Columbia, South Carolina, since January 2015. Immediately prior to that date, he served as Executive Vice President and Director of Public Affairs for First Citizens Bank and Trust Company, Inc. (which was merged into First-Citizens Bank & Trust Company in January 2015) since August 2002. From May 2000 to July 2002, he was President and Chief Executive Officer of South Carolina Community Bank, in Columbia, South Carolina. Mr. Bennett has been actively involved with the Columbia Urban League for more than 25 years, and served as League Chairman in 2000. Mr. Bennett serves on the boards of Palmetto Health Alliance, headquartered in Columbia, South Carolina, and Claflin University, located in Orangeburg, South Carolina.

Experience and Qualifications

Mr. Bennett has been a banker for over 25 years. In 1989, he became the youngest bank president in South Carolina when he was named President of Victory Savings Bank (the predecessor of South Carolina Community Bank), a position he held before joining First Citizens Bank. Mr. Bennett's business experience, coupled with his tenure on our Board, makes him an effective advisor. His high visibility in communities we serve makes him an effective liaison between our Company and members of those communities.

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CONTINUING DIRECTORS

Class I Directors — Terms to Expire at the Annual Meeting in 2018

Lynne M. Miller

Environmental Consultant

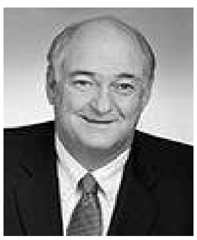
Director since 1997
Age 65

Biographical Information

Ms. Miller co-founded Environmental Strategies Corporation, an environmental consulting firm in Reston, Virginia, in 1986, and served as President from 1986 until 1995, and as Chief Executive Officer from 1995 until September 2003 when the firm was acquired by Quanta Capital Holdings, Inc., a specialty insurer, and its name was changed to Environmental Strategies Consulting LLC. She was Chief Executive Officer of Environmental Strategies Consulting LLC, a division of Quanta Technical Services LLC, from September 2003 through March 2004. From April 2004 through July 2005, she was President of Quanta Technical Services LLC. From August 2005 until her retirement in August 2006, she was a Senior Business Consultant at Quanta Capital Holdings. Since her retirement, Ms. Miller has been an environmental consultant, and since December 2016 she has served as a director of Gannett Fleming Affiliates, Inc., the holding company for an engineering design and construction management firm. Ms. Miller previously served as a director of Adams National Bank, a subsidiary of Abigail Adams National Bancorp, Inc., in Washington, D.C. from May 1998 until October 2008.

Experience and Qualifications

Ms. Miller has over 25 years of environmental consulting experience. She founded a successful environmental consulting firm, which she grew to over 180 professional staff before selling it in 2003. Ms. Miller's experience as an environmental consulting firm owner and as an environmental consultant makes her an astute advisor on the environmental issues facing our Company, and her prior service on the board of a financial institution provided her with valuable experience in financial and regulatory matters.



James W. Roquemore

Chief Executive Officer and Chairman, Patten Seed Company General Manager, Super-Sod/Carolina

Director since 2007
Age 62

Biographical Information

Mr. Roquemore is Chief Executive Officer and Chairman of Patten Seed Company, headquartered in Lakeland, Georgia, and General Manager of Super-Sod/Carolina, a company that produces and markets turf grass, sod and seed. He has held these positions for more than five years. Mr. Roquemore is a director of South State Bank, N.A., and South State Corporation (formerly South Carolina Bank and Trust, N.A., and SCBT Financial Corporation, respectively). He has served on the Southeast Region and National boards of the Boy Scouts of America and as a Co-Chairman of South Carolina's Council on Competitiveness (formerly known as New Carolina), and he is the past President of Palmetto Agribusiness Council.

Experience and Qualifications

Mr. Roquemore is a highly successful agricultural business owner who resides in our service territory. Because agriculture is an important component of the economy in our South Carolina service area, his knowledge of this sector and his contacts are important to us. Mr. Roquemore's business experience and economic development activities in our state make him an effective advisor on issues unique to us and the customers we serve. His service on the boards of a financial institution and its holding company, which is also a public company, gives him valuable experience in financial and regulatory matters.

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CONTINUING DIRECTORS

Class I Directors — Terms to Expire at the Annual Meeting in 2018

Maceo K. Sloan

Chairman, President and Chief Executive Officer, Sloan Financial Group, Inc.

Director since 1997
Age 67

Biographical Information

Mr. Sloan is Chairman, President and Chief Executive Officer of Sloan Financial Group, Inc., a financial holding company, in Durham, North Carolina and he has held these positions for more than five years. From 1986 to September 2016, Mr. Sloan was affiliated with NCM Capital Management Group, Inc. and NCM Capital Advisors, Inc. During that time he held the following positions: Chairman (1991 to September 2016), Chief Executive Officer (1986 to September 2016), Chief Investment Officer (1991 to 2012), and Chief Compliance Officer (2015 to September 2016). Mr. Sloan served as the Principal Officer of the NCM Capital Investment Trust from 2007 to 2011. From 2009 to 2012, Mr. Sloan was Chairman of, and since 1991 has served as a member of, the College Retirement Equities Fund (CREF) Board of Trustees. Mr. Sloan previously served as Chairman of the Board of M&F Bancorp, Inc. from June 2005 to December 2008, as a member of its Board from 2001 to 2008, and as a director of its subsidiary, Mechanics and Farmers Bank, in Durham, North Carolina, from 1980 to 2001 and from 2005 to 2008.

Experience and Qualifications

Mr. Sloan is an attorney and a chartered financial analyst. His experience owning and operating investment management companies and a financial holding company has provided him with an investment background and understanding of global financial matters, all of which make him an important resource to us. Additionally, his service with these companies, as well as with a financial institution and a major retirement fund, has provided him with experience in highly regulated industries and valuable instincts and insights.

Class II Directors — Terms to Expire at the Annual Meeting in 2019*

Gregory E. Aliff

Certified Public Accountant and Retired Partner, Deloitte & Touche LLP

Director since 2015
Age 63

Biographical Information

Mr. Aliff, a certified public accountant, retired from Deloitte & Touche LLP in May 2015, after serving as a Partner for 28 years. During his career at Deloitte, Mr. Aliff served as the Vice Chairman and Senior Partner of Energy & Resources, and he was a leader of Deloitte's Energy and Natural Resources Management Services. Since September 2015, Mr. Aliff has been a director of California Water Service Group, Inc. in San Jose, California. He also serves as a director of Grid Alternatives in Oakland, California.

Experience and Qualifications

Mr. Aliff's experience as a long-term partner at Deloitte & Touche LLP, including in particular his focus on energy and natural resources and energy and natural resources management, provided him not only with a financial and accounting background that add depth to our Audit Committee, but also a focus on our industry that uniquely qualifies him to serve on our Board. His service on the board of directors of another regulated entity that is also a public company provides him with important experience and perspectives with respect to operations and the regulatory compliance required for highly regulated businesses and public company best practices.

*Mr. James M. Micali is currently a member of Class II but is not shown because he will reach the age of 70 in December 2017, and accordingly, his term as a director will expire in accordance with our Articles of Incorporation at the 2017 Annual Meeting. The Board of Directors has reduced the size of the Board to ten effective at the 2017 Annual Meeting so that the Board will have sufficient time to consider board member recruitment.

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CONTINUING DIRECTORS

Class II Directors — Terms to Expire at the Annual Meeting in 2019

Sharon A. Decker

Chief Operating Officer for Tryon Equestrian Partners Carolinas Operations

Director since 2015; previously a director from 2005 until 2013
Age 60

Biographical Information

Mrs. Decker served as Senior Vice President of Strategic Initiatives for Tryon International Equestrian Center in Mill Spring, North Carolina, beginning in September 2015 until December 2015 when she was named Chief Operating Officer for Tryon Equestrian Partners Carolinas Operations. She currently serves in that capacity with responsibility for the Tryon International Equestrian Center, Tryon Resort and related Carolina-based businesses. Mrs. Decker had been President of NURAY Media, dba NURAY Digital, from January 2015 until August 2015, and served as the Secretary of Commerce for the State of North Carolina from January 2013 until December 2014. Mrs. Decker was the founder and principal of The Tapestry Group, a faith-based, non-profit organization, located in Rutherfordton, North Carolina, from August 2004 until January 2013. Mrs. Decker previously served as President of Tanner Holdings, LLC and Doncaster, apparel manufacturers, from August 1999 until September 2004. Mrs. Decker is a director of Coca-Cola Bottling Company Consolidated, Inc. in Charlotte, North Carolina. She also served as a director of Family Dollar Stores, Inc., in Charlotte, North Carolina, until June 2015. She previously served as a Director of our Company from 2005 until April 2013, when she resigned to become North Carolina's Secretary of Commerce.

Experience and Qualifications

Mrs. Decker's prior service on our Board and various committees of the Board provide her with experience relative to our operations and initiatives. Mrs. Decker's service as Secretary of Commerce for the State of North Carolina provided her with economic development experience, as well as experience dealing with various aspects of government, including working with the executive and legislative branches of state government. Her executive-level experience, along with her experience serving on the boards of two other public companies, prepared her well to offer our Board and management insights on various aspects of corporate operations. Prior to first joining our Board in 2003, Mrs. Decker served as an executive officer of another public utility. Her role there focused on residential service matters and implementation of demand side management programs, both extremely important to our Company's future success.

Kevin B. Marsh

Chairman, Chief Executive Officer, President and Chief Operating Officer, SCANA Corporation

Director since 2011
Age 61

Biographical Information

Mr. Marsh has been employed by SCANA or its subsidiaries for over 30 years, and since December 2011 he has served as SCANA's Chairman of the Board and Chief Executive Officer. Since January 2011, he has also served as our President and Chief Operating Officer. He served as our Chief Financial Officer from 1996 to April 2006, and served as a Senior Vice President from 1998 to January 2011. In addition, he served as President of our principal subsidiary, South Carolina Electric & Gas Company, from April 2006 to November 2011. Mr. Marsh served on the boards of First Citizens Bank and Trust Company, Inc. and its holding company, First Citizens Bancorporation, Inc., from 2004 until their mergers with First-Citizens Bank & Trust Company and First Citizens BancShares, Inc. in 2015 and 2014, respectively, including serving as Chair of the Compensation Committee.

Experience and Qualifications

Mr. Marsh brings significant hands-on experience to our Board having served our Company in senior operational and financial positions for over three decades, as well as having practiced as a certified public accountant for several years prior to joining us. His vast financial, operational and regulatory experience with us and as a director of a financial institution and its holding company makes him a trusted and experienced advisor for our Board.

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BOARD MEETINGS — COMMITTEES OF THE BOARD

The Board held four quarterly Board meetings, one Code of Conduct and Ethics training session, one Federal Energy Regulatory Commission training session, and several strategy sessions in 2016. Each incumbent director attended 100% of all meetings of the Board and Committees of which he or she was a member during 2016. Our directors are expected to attend our Annual Meeting of Shareholders, and all of our directors attended the 2016 Annual Meeting of Shareholders.

Committees of the Board

The table below identifies the members of each of the Board's Committees as of December 31, 2016. The information below the table identifies the current members of each Board Committee and briefly summarizes the principal functions of each Committee. The Charters of the Audit Committee, the Compensation Committee, and the Nominating and Governance Committee, can be found on SCANA's website at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not part of this proxy statement or any report filed with the Securities and Exchange Commission) under the caption, "About – Corporate Governance," and copies are also available in print upon request to the Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033.

Committee Member	Audit*	Compensation	Executive	Nominating and Governance	Nuclear Oversight
G. E. Aliff**	Chairman		√	√	
J. A. Bennett	√	Chairman	√		
J. F. A. V. Cecil	√	√			
S. A. Decker		√			√
D. M. Hagood (Lead Director)			√	√	√
K. B. Marsh			Chairman		
J. M. Micali	√	√	√	Chairman	
L. M. Miller	√			√	
J. W. Roquemore		√	√		Chairman
M. K. Sloan		√			√
A. Trujillo				√	√

* Established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934.

** Mr. Aliff is also our "audit committee financial expert" as defined under Item 407(d)(5) of the Securities and Exchange Commission's Regulation S-K. Mr. Aliff is independent as defined by the New York Stock Exchange Listing Standards.

AUDIT COMMITTEE
(Current Members)

G. E. Aliff, Chairman
J.A. Bennett
J. F. A. V. Cecil
J. M. Micali
L. M. Miller

The Audit Committee consists entirely of independent directors. The Committee meets, at least quarterly, to discuss and evaluate the scope and results of audits and our accounting procedures and controls. In addition, the Committee meets, at least quarterly, separately with management, the Company's General Counsel, internal auditors, the independent registered public accounting firm, the Company's Risk Management Officer and corporate compliance. The Committee reviews major issues regarding accounting principles and financial statement preparation as well as reviews the Company's quarterly and annual financial statements before submission to the Board of Directors for approval and prior to dissemination to our shareholders, the public and regulatory agencies.

In addition, the Audit Committee appoints (subject to ratification by the shareholders) the independent registered public accounting firm, approves and reviews the scope of each year's audit, and exercises oversight of the firm's work. The Committee also sets the compensation of the independent registered public accounting firm and pre-approves all services to be performed by the firm. Additionally, the Audit Committee evaluates the independent registered public accounting

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firm's qualifications, performance and independence, including a review of the lead audit partner's performance, taking into account the opinions of the Company's management and internal auditors, and assures regular rotation of the lead audit partner as required by law. Further discussion regarding the Audit Committee's pre-approval of such audit services and associated fees can be found under "Pre-Approval of Auditing Services and Permitted Non-Audit Services" on page 63.

The Audit Committee also reviews the scope and effectiveness of our risk management program which includes the review of quarterly reports pertaining to significant risks. The Committee's role in risk oversight is discussed in more detail on page 18 under the heading "Board's Role in Risk Oversight." Additionally, the Audit Committee reviews, on a quarterly basis, the responsibilities and effectiveness of our internal auditing and corporate compliance departments, and reviews reports from those departments regarding the Company's conformity with applicable legal requirements and with our Code of Conduct. The Committee reviews with management its assessment of internal controls over financial reporting and disclosure controls and procedures. The Audit Committee also reviews with the Board of Directors our compliance with legal, regulatory, and ethical requirements, and the performance and independence of our external auditors and the performance and independence from management of our internal auditors. Additionally, the Committee constitutes the Qualified Legal Compliance Committee.

On an annual basis, the Committee evaluates its own performance and the adequacy of its charter, and recommends to the Board of Directors any improvements to the charter that the Committee deems appropriate.

The Committee met four times during 2016. For a full list of responsibilities, see the Audit Committee's Charter at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not part of this proxy statement or any report filed with the Securities and Exchange Commission) under the caption "About – Corporate Governance – Audit Committee."

The Board has determined that Mr. Aliff is our "audit committee financial expert" as defined under Item 407(d)(5) of the Securities and Exchange Commission's Regulation S-K. Mr. Aliff is independent as defined by the New York Stock Exchange Listing Standards.

COMPENSATION COMMITTEE
(Current Members)

J. A. Bennett, Chairman
J. F. A. V. Cecil
S. A. Decker
J. M. Micali
J. W. Roquemore
M. K. Sloan

The Compensation Committee consists entirely of independent directors. The Committee reviews and makes recommendations to the Board with respect to compensation plans, recommends to the Board persons to serve as our senior officers and as senior officers of our subsidiaries, and recommends to the Board salary and compensation levels, including all benefits, for our officers and officers of our subsidiaries. The Committee also approves goals and objectives with respect to the compensation of the Chief Executive Officer, evaluates the Chief Executive Officer's performance and along with the other independent directors sets his compensation based on this evaluation.

Additionally the Committee reviews succession and continuity planning with the Chief Executive Officer, reviews operating performance relative to the Company's bonus and incentive programs and reviews management's Compensation Discussion and Analysis relating to executive compensation prior to its inclusion in our proxy statement. Further, the Committee approves the inclusion of a Compensation Committee Report in our proxy statement as well as reviews the level of SCANA stock ownership by senior executive officers to determine if each is in compliance with the Company's minimum ownership requirement, and, as may be requested and appropriate, grants temporary waivers from such requirements.

The Committee met three times during 2016. For a full list of responsibilities, see the Compensation Committee's Charter at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not part of this proxy statement or any report filed with the Securities and Exchange Commission) under the caption "About – Corporate Governance – Compensation Committee."

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EXECUTIVE COMMITTEE
(Current Members)

K. B. Marsh, Chairman
G. E. Aliff
J. A. Bennett
D. M. Hagood
J. M. Micali
J. W. Roquemore

The Executive Committee exercises the powers of the full Board of Directors when the Board is not in session or cannot be called into session in a timely manner to deal with a time sensitive circumstance, with the exception of certain powers specifically reserved to the full Board of Directors by statute. The Committee also advises the Chief Executive Officer on other matters important to the Company (due to the size of our Board of Directors, and availability of our Directors to us, the Executive Committee is rarely required to meet). Although the Chief Executive Officer from time to time sought the advice of the Executive Committee, there were no formally called meetings of the Executive Committee during 2016.

NOMINATING AND GOVERNANCE COMMITTEE
(Current Members)

J. M. Micali, Chairman
G. E. Aliff
D. M. Hagood
L. M. Miller
A. Trujillo

The Nominating and Governance Committee consists entirely of independent directors. The Committee identifies individuals whom the Committee believes are qualified to become Board members in accordance with the nominating criteria set forth below under "Governance Information —Director Qualification Criteria" (the "Director Qualification Criteria"), and recommends that the Board select such individuals as nominees to stand for election at each Annual Meeting of Shareholders of SCANA. In addition, the Committee reviews and evaluates all persons recommended by shareholders to be Board nominees for director in accordance with the Director Qualification Criteria, evaluates the qualifications and performance of incumbent directors and determines whether to recommend them to the Board for re-election, and in the case of a Board vacancy (including a vacancy created by an increase in the size of the Board), recommends to the Board in accordance with the Director Qualification Criteria an individual to fill such vacancy either through appointment by the Board or through election by shareholders.

The Committee also reviews the independence of SCANA's Directors as defined by the New York Stock Exchange and as set forth in SCANA's Governance Principles and makes recommendations to the Board regarding director independence. The Committee reviews the level and form of director compensation and recommends changes to the Board for consideration and approval. At least annually, the Committee reviews the level of SCANA stock ownership by directors to determine if each director is in compliance with the Company's minimum share ownership requirement. Additionally, the Committee reviews reports and disclosures of insider and affiliated party transactions and makes recommendations to the Board regarding such transactions.

The Committee periodically evaluates the desirability of, and recommends to the Board, any changes in the size, composition, organization and operational structure of the Board. Also, the Committee, annually, or to fill vacancies, identifies Board members qualified to serve on committees of the Board in accordance with the Board Committee Member Qualifications, and recommends such persons to the Board for appointment to such committees, including a recommended Chairperson for each committee, as well as annually, or to fill vacancies, recommends to the Board the appointment of a Lead Director. The Committee annually reviews the membership and responsibilities of Board committees and recommends to the Board any changes that may be appropriate, and reviews and revises as necessary, SCANA's Governance Principles, taking into account provisions of the Securities Exchange Act of 1934, the listing standards of the New York Stock Exchange and any other source or sources the Committee deems appropriate. The Committee also provides guidance and assistance, as needed, to the Board in performing the Board's annual self evaluation.

The Committee met six times during 2016. For a full list of responsibilities, see the Nominating and Governance Committee's Charter at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not part of this proxy statement or any report filed with the Securities and Exchange Commission) under the caption "About – Corporate Governance – Nominating and Governance Committee."

NUCLEAR OVERSIGHT COMMITTEE (Current Members)	
J. W. Roquemore, Chairman S. A. Decker D. M. Hagood M. K. Sloan A. Trujillo	The Nuclear Oversight Committee consists entirely of independent directors. The Committee meets at least quarterly to monitor, discuss, and evaluate our nuclear operations, which include regulatory matters, operating results, training and other related topics. The Committee periodically tours the V.C. Summer Nuclear Station and its training facilities. The Committee also reviews with the Institute of Nuclear Power Operations, on a periodic basis, its appraisal of our nuclear operations. Additionally, the Committee routinely presents an independent report to the Board on the status of our nuclear operations. The Committee met four times during 2016.

GOVERNANCE INFORMATION

Governance Principles

Our Governance Principles can be found on our website at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not part of this proxy statement or any report filed with the Securities and Exchange Commission) under the "About – Corporate Governance – Governance Principles" caption, and are also available in print upon request to the Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033.

Director Independence

Our Governance Principles require that a majority of our directors be independent under the New York Stock Exchange Listing Standards and under any Director Qualification Standards recommended by the Board of Directors. To be considered "independent" pursuant to the SCANA Director Qualification Standards, a director must be determined by resolution of the Board as a whole, following thorough deliberation and consideration of all relevant facts and circumstances, to have no material relationship with us except that of director and to satisfy the independence standards of the New York Stock Exchange. Under the SCANA Director Qualification Standards, a director is required to be unencumbered and unbiased and able to make business judgments in our long-term interests and those of our shareholders as a whole, to deal at arm's length with us, and to disclose all circumstances material to the director that might be perceived as a conflict of interest. The Director Qualification Standards are set forth in our Governance Principles, which are available on our website as noted above and further described herein under "Director Qualification Criteria" on page 19.

Our Governance Principles also prohibit Audit Committee members from having any direct or indirect financial relationship with us other than the ownership of our securities and compensation as directors and committee members.

The Board has determined that all of our current directors and director nominees, except Mr. Marsh who is our current Chairman, President, Chief Executive Officer and Chief Operating Officer, are independent under the New York Stock Exchange Listing Standards and our Governance Principles. Mr. Stowe, who served as a director until the 2016 Annual Meeting, was also independent under the New York Stock Exchange Listing Standards and our Governance Principles. The Board has also determined that each member of the Audit Committee, Compensation Committee, and Nominating and Governance Committee is independent under the New York Stock Exchange Listing Standards and our Governance Principles.

Board Leadership Structure, Executive Sessions of Non-Management Directors and Lead Director

Our bylaws provide for a Chairman of the Board, to be chosen by the Board from among its members, who shall, if present, preside at meetings of the shareholders and Board of Directors, who may call special meetings of the shareholders and the Board of Directors, and who shall perform such other duties as may be assigned by the Board. The bylaws also permit the Chief Executive Officer, if he or she is a member of the Board, to be chosen as the Chairman. Our Governance Principles provide for the positions of Chairman and Chief Executive Officer to be held by the same person, and for more than 20 years, our Chief Executive Officer has been chosen as Chairman of the Board.

We believe this leadership structure is appropriate because it has served us well for over two decades, and because all of our current directors are independent, except Mr. Marsh, who is our Chairman, Chief Executive Officer, President and

Chief Operating Officer. Many of our directors also live and work, or have substantial business interests in our service area; therefore, they have access to information about us and our operations from sources other than our management's presentations to the Board. Further, South Carolina law and our bylaws make it clear that the business and affairs of the Company are managed under the direction of the Board of Directors, and that management control is subject to the authority of the Board of Directors to appoint and remove any of our officers at any time.

To promote open discussion among themselves, our independent directors meet regularly in executive session without members of management present. The Board annually elects an independent Lead Director to preside at all meetings at which the Chairman is not present, including executive sessions of the independent directors held at each regularly scheduled Board meeting. In 2016, Mr. Hagood was elected independent Lead Director to serve until the 2017 Annual Meeting of Shareholders. After the 2017 Annual Shareholders' Meeting, the Board will again appoint an Independent Lead Director to serve until the 2018 Annual Meeting of Shareholders. The independent Lead Director also has the authority to call meetings of the independent directors when necessary or appropriate. The Chairs of the Audit, Compensation, Nuclear Oversight, and Nominating and Governance Committees of the Board each preside as the Chair at meetings of independent directors at which the Independent Lead Director is not present when the principal items to be considered are within the scope of authority of his or her Committee.

Board's Role in Risk Oversight

As noted above, our business and affairs are managed under the direction of our Board of Directors. This includes the Board overseeing the types and amounts of risks undertaken. In discharging its oversight responsibilities, the Board relies on a combination of the business experience of members of the Board and the expertise and business experience of our officers and employees, as well as, from time to time, advice of various consultants and experts. An appropriate balancing of risks and potential rewards with the long-term goals of the Company is, and historically has been, implicit in the decisions and policies of the Board. Because risk oversight is so thoroughly interwoven into the direction of the Board, other than as set forth below, no special provision has been made for that oversight in the Board's leadership structure.

The Board has established an executive senior officer-level Risk Management Committee which reports directly to the Audit Committee of the Board. The Risk Management Committee is comprised of the Company's senior executive officers, one of whom is the Risk Management Officer. The Company's Chief Executive Officer serves as Chair of the Risk Management Committee. Committee membership is comprised of all senior executive officers in order to bring together expertise in general business and all operational areas, as well as finance, legal, administrative and regulatory areas. The Risk Management Officer oversees a staff of 8 employees with primary responsibilities in the area of risk management.

The Risk Management Committee conducts regularly scheduled meetings at which the Committee receives presentations from management representatives. The Committee also meets as needed between regularly scheduled meetings. Pursuant to authority granted by the Board of Directors, the Committee sets policies and guidelines for risk management. The Committee has also established sub-committees with expertise tailored to the review, discussion and monitoring of risks of a particular operation.

At each quarterly meeting of the Board, the Audit Committee receives a report from the Risk Management Officer. Several members of the Risk Management Committee are also present at the Audit Committee meetings to provide details of the Committee's work and respond to questions raised by Audit Committee members. Also, at each quarterly meeting of the Board of Directors, the Board reviews and discusses a report prepared by the Company's Risk Management Officer and approved by the Risk Management Committee, which sets forth certain high-level risks identified by the Company's senior executive officers and others. The report also provides the current status of such high-level risks, and further identifies where the primary responsibility for risk oversight resides, including both at the Board and Committee level, and identifies the senior executive officer who has primary responsibility for oversight of the particular risk.

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Director Nomination Process

The Nominating and Governance Committee recommended to the Board the individuals nominated for Director positions at the Annual Meeting.

Director Candidate Recommendations. The Nominating and Governance Committee will consider for recommendation to the Board as Board of Directors' nominees, candidates recommended by shareholders if the shareholders comply with the following requirements. If a shareholder wishes to recommend a candidate to the Nominating and Governance Committee for consideration as a Board of Directors' nominee, such shareholder must confirm his or her share ownership and submit in writing to the Nominating and Governance Committee the recommended candidate's name, a brief resume setting forth the recommended candidate's business and educational background and qualifications for service, and a notarized consent signed by the recommended candidate stating the recommended candidate's willingness to be nominated and to serve. This information must be delivered to the SCANA Nominating and Governance Committee, c/o the Corporate Secretary at the Company's address and must be received no later than 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting for a potential candidate to be considered as a potential Board of Directors' nominee. The Nominating and Governance Committee may request further information if it determines a potential candidate may be an appropriate nominee. Director candidates recommended by shareholders that comply with these requirements will be considered on the same basis as candidates otherwise chosen by the Nominating and Governance Committee.

Shareholder Director Nominees. Director candidates recommended by shareholders will not be considered for recommendation by the Nominating and Governance Committee as potential Board of Directors' nominees if the shareholder recommendations are received later than 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting. If the Nominating and Governance Committee chooses not to recommend a shareholder candidate as a Board of Directors' nominee, or if a shareholder chooses to personally nominate a candidate, the shareholder may come to an annual meeting and nominate a director candidate for election at the annual meeting if the shareholder has given notice of his or her intention to do so in writing to the SCANA Corporate Secretary at least 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting. Such shareholder nominations must also comply with the other requirements in our bylaws. Any shareholder may request a copy of the relevant bylaw provision by writing to the Office of the Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033. Nominations not made in accordance with these requirements may be disregarded by the presiding officer of the meeting, and upon his or her instructions, the voting inspectors shall disregard all votes cast for each such nominee.

Shareholder Proxy Access Director Nominees. After reviewing the increasing support of institutional shareholders and others for proxy access, and determining the appropriate proxy access parameters for our Company, we amended our Bylaws on December 30, 2016 to allow any shareholder (or group of no more than 20 shareholders) owning 3% or more of the Company's common stock continuously for at least 3 years to nominate candidates for election for up to the greater of one director or 20% of the number of directors to be elected if the Board is classified, or the greater of two directors or 20% of the number of directors in office if the Board is not classified, and require the Company to include such nominees in our proxy statement and on our proxy card. In order to nominate a director pursuant to our proxy access bylaw, shareholders who meet the eligibility and other requirements set forth in Article I, Section 7 of our Bylaws must send notice to our Corporate Secretary at our executive offices of intention to nominate a director pursuant to the proxy access bylaw. The notice must provide the detailed information and meet the other requirements set forth in our proxy access bylaw, and be timely received by our Corporate Secretary as provided in our proxy access bylaw. The shareholder also must comply with the other requirements in the bylaws. Any shareholder may request a copy of the relevant bylaw provision by writing to the Office of the Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033.

Director Qualification Criteria

In identifying and evaluating potential nominees, the Nominating and Governance Committee Charter directs the Committee to take into account applicable requirements for directors under the Securities Exchange Act of 1934, the Listing Standards of the New York Stock Exchange and the Director Qualification Standards in our Governance Principles, including our policy that a majority of our directors be independent.

The Nominating and Governance Committee may take into consideration such other factors and criteria as it deems appropriate in evaluating a candidate, including his or her knowledge, expertise, skills, integrity, judgment, business or

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other experience and reputation in the business community, the interplay of the candidate's experience with the experience of other Board members, diversity, and the extent to which the candidate would be a desirable addition to the Board and any committees. Although the Nominating and Governance Committee does not have a specific policy with regard to the consideration of diversity in identifying director nominees, the Committee considers racial, cultural and gender diversity, as well as diversity in business and personal experience and skill sets among all of the directors as part of the total mix of information it takes into account in identifying nominees. Additionally, the Director Qualification Standards set forth in our Governance Principles include the following:

- Directors must possess and have demonstrated the highest personal and professional ethics, integrity and values consistent with ours;
- Directors must be unencumbered and unbiased and able to make business judgments in our long-term interests and those of our shareholders as a whole;
- Directors must deal at arm's length with us and our subsidiaries and disclose all circumstances material to the director that might be perceived as a conflict of interest;
- Directors must be committed to the enhancement of the long-term interests of our shareholders;
- Directors must be willing to challenge the strategic direction of management, exercising mature judgment and business acumen;
- Directors must be willing to devote sufficient time and care to the exercise of their duties and responsibilities;
- Directors must possess significant experience in management positions of successful business organizations;
- Directors who serve as chief executive officers or equivalent positions should not serve on more than two boards of public companies in addition to our Board; other directors should not serve on more than four boards of public companies in addition to our Board; and
- The term of office of a director who is not a salaried employee of SCANA will expire at the annual meeting next preceding the date on which such director attains age 70.

Our bylaws require that our independent directors hold SCANA common stock equal to the number of shares granted in the five most recent annual stock retainers, as such retainer may be adjusted from time to time.

Director Share Ownership Requirements

As noted in the Director Qualification Standards set forth in the preceding section, our bylaws require that our independent directors hold SCANA common stock equal to the number of shares granted in the five most recent annual stock retainers. Currently, a portion of the retainer fees paid to independent directors is required to be paid in shares of our common stock. For 2016, the number of shares issued to each independent director to satisfy the annual stock retainer was 1,823. As of February 2017, all independent directors whose terms will continue after the Annual Meeting, or who have been nominated for reelection, met this stock ownership requirement, with the exception of our newest directors Mrs. Decker and Messrs. Aliff, Cecil and Trujillo who are all currently on track to meet the requirement. Directors Decker and Aliff have until October 2021 and Directors Cecil and Trujillo have until October 2019 to acquire the required level of stock ownership. All subsequently elected independent directors will have six years from the date of their election to the Board to meet the requirement. The Nominating and Governance Committee conducts an annual review of the level of share ownership for each independent director to ensure compliance with the requirement. The Nominating and Governance Committee also has the discretion to grant a temporary waiver of the minimum share ownership requirement if an independent director demonstrates to the Nominating and Governance Committee that such a waiver is appropriate due to a financial hardship or for other good reason.

Under the Director Compensation and Deferral Plan, independent directors may make an annual irrevocable election to defer all or a portion of the annual stock retainer fee into a hypothetical investment in our common stock, with distribution from the Plan to be ultimately payable in shares of our common stock. Independent directors may also elect for other fees to be deferred into a hypothetical investment in our common stock under the Plan, with distribution from the Plan to be ultimately payable in shares of common stock. Shares held directly and amounts deferred pursuant to the Director

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Compensation and Deferral Plan and denominated in shares are taken into consideration in determining if our independent directors meet the minimum share ownership requirement under our bylaws. Eligible Directors may also defer all or a portion of their cash retainer fees and 100% (but not less than 100%) of their annual stock retainer fees into a hypothetical investment in our common stock under the Executive Deferred Compensation Plan, and those shares are also taken into consideration in determining if our Directors meet the minimum share ownership requirements. See "Executive Compensation — Executive Deferred Compensation Plan" beginning on page 47, and "Director Compensation — Director Compensation and Deferral Plan" on page 56.

Majority Withheld Director Resignation Policy

Our Company and our Board are supportive of majority voting for Directors, and we continue to evaluate how we can further implement majority voting for directors. At present, our Governance Principles provide for a modified majority voting policy for the election of our directors, pursuant to which each director nominee agrees that, as a condition to being nominated, if, in an uncontested election of directors, such nominee receives a greater number of voting instructions designated as "withheld" from his or her election than votes cast as "for" his or her election, then such nominee will, within five days following the certification of the shareholder vote, tender his or her written resignation to the Chairman of the Board for consideration by the Nominating and Governance Committee. The Nominating and Governance Committee will consider such tendered resignation, and promptly following the date of the shareholders' meeting at which the election occurred, will make a recommendation to the Board concerning the acceptance or rejection of such resignation. In determining its recommendation to the Board, the Nominating and Governance Committee will consider all factors deemed relevant by the members of the Committee including, without limitation, the stated reason or reasons why shareholders who cast "withhold" votes for the director did so, the qualifications of the director (including, for example, the impact that the director's resignation would have on the Company's compliance with the requirements of the Securities and Exchange Commission, the New York Stock Exchange and our Corporate Governance Principles), and whether the director's resignation from the Board would be in the best interests of the Company and its shareholders.

The Nominating and Governance Committee also will consider a range of possible alternatives concerning the director's tendered resignation as members of the Committee deem appropriate, including, without limitation, acceptance of the resignation, rejection of the resignation, or rejection of the resignation coupled with a commitment to seek to address and cure the underlying reasons reasonably believed by the Nominating and Governance Committee to have substantially resulted in the voting instructions designated as "withheld". The Board will take formal action on the Nominating and Governance Committee's recommendation no later than 90 days following the date of the shareholders' meeting at which the election occurred. Following the Board's decision on the Nominating and Governance Committee's recommendation, the Company will promptly disclose, in a Form 8-K filed with the Securities and Exchange Commission, the Board's decision, together with a full explanation of the process by which the decision was made and, if applicable, the Board's reason or reasons for rejecting the tendered resignation.

Communications with the Board of Directors, Including Non-Management Directors

Shareholders and other interested parties can communicate with the Board, with the independent directors as a group or with any director by writing to them, c/o Gina Champion, Deputy General Counsel and Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033, or by sending an e-mail to SCANAindependentdirectors17@scana.com (for correspondence to the independent directors), to SCANAchairman17@scana.com (for correspondence to the CEO/Chairman) or to gchampion@scana.com (for correspondence to a particular director). Interested parties also may communicate with the chair of the following Committees by sending an e-mail to: auditchair17@scana.com, compensationchair17@scana.com, or nomandgovchair17@scana.com. The Corporate Secretary may initially review communications to Directors and send a summary to the Directors, but has discretion to exclude from transmittal any communications that are commercial advertisements or other forms of solicitation or individual service or billing complaints (although all communications are available to the Directors at their request). The Corporate Secretary will forward to the Directors any communications raising substantive issues.

Prohibition on Hedging, Margining or Pledging of Shares

Our Insider Trading Policy prohibits officers, directors, employees and related persons from pledging, margining or engaging in hedging transactions with respect to shares of the Company's common stock.

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SCANA's Code of Conduct & Ethics

All of our employees (including the Chief Executive Officer, Chief Financial Officer, President and Controller) and Directors are required to abide by the SCANA Code of Conduct & Ethics (the "Code of Conduct") to ensure that our business is conducted in a consistently legal and ethical manner. The Code of Conduct forms the foundation of a comprehensive process that promotes compliance with corporate policies and procedures, an open relationship among colleagues that contributes to good business conduct, and a belief in the integrity of our employees. Our policies and procedures cover all areas of business conduct and require adherence to all laws and regulations applicable to the conduct of our business.

The full text of the Code of Conduct is published on our website, at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not part of this proxy statement or any report filed with the Securities and Exchange Commission) under the "About – Corporate Governance" caption, and a copy is also available in print upon request to the Office of the Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033. We intend to disclose future amendments to, or waivers from, certain provisions of the Code of Conduct on our website within two business days following the date of such amendment or waiver.

RELATED PARTY TRANSACTIONS

Our Governance Principles and Nominating and Governance Committee Charter address independence requirements for our Directors. As part of our independence analysis, our Nominating and Governance Committee must review and assess any related party transactions involving our Directors and their immediate family members and certain of their affiliates as required by the New York Stock Exchange Listing Standards. Our Governance Principles also address Director requirements for avoidance of conflicts of interest and disclosure of conflicts of interest or potential conflicts of interest, and prohibit loans or extensions of credit to Directors. Our Code of Conduct addresses requirements for avoidance of conflicts of interest by all of our employees. Our Governance Principles, Nominating and Governance Committee Charter and Code of Conduct are all written documents. With the exception of annual director and officer questionnaires, our Governance Principles, our Code of Conduct, and our Nominating and Governance Committee Charter, there are no additional written policies and procedures relating to the review, approval or ratification of related party transactions by the Board.

To help us perform our independence and related party transaction analysis, we require that each senior executive officer, executive officer, director and director nominee complete an annual questionnaire and report all transactions with us in which such persons (or their immediate family members and certain of their affiliates) had or will have a direct or indirect material interest (except for salaries and other compensation and benefits, directors' fees, and dividends on our stock). It is our general intention to avoid such transactions. Our General Counsel reviews responses to the questionnaires and any other information about related party transactions that may be brought to his attention. We use the questionnaires and the annual Code of Conduct training to help ensure the effective implementation and monitoring of compliance with such policies and procedures. If any such related party transactions are disclosed, they are reviewed by the Nominating and Governance Committee pursuant to the requirements of its Charter. If appropriate, any such transactions are submitted to the Board for approval.

The Nominating and Governance Committee does not use any formal written standards in determining whether to submit a related party transaction to the Board for approval. As noted above, we attempt to avoid such transactions altogether. On the rare occasions when such transactions have arisen, our Nominating and Governance Committee, which is comprised solely of independent Board members, reviewed the proposed or actual transactions and utilized their business judgment to determine which of them should be submitted for review to the full Board. In practice, all such transactions that have arisen in recent years have been reviewed by the full Board, even when they were well below the threshold for proxy statement disclosure and below the threshold at which director independence could be compromised.

The types of transactions that have been reviewed in the past include the purchase and sale of goods, services or property from companies for which our Directors serve as executive officers or directors, the purchase of financial services and access to lines of credit from banks for which our directors serve as executive officers or directors, and senior executive officer relocation and severance benefits. During 2016, the only potential related party transaction discussed was a request by a Director to serve on the board of another company. No related party issues were identified as a result of that review.

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SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

SECURITY OWNERSHIP OF MANAGEMENT

The following table lists the amounts of our common stock beneficially owned on February 21, 2017, by each director, each nominee, each person named in the Summary Compensation Table on page 42, and all directors and executive officers as a group.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)(2)(3)(4)	Percent of Class
K. B. Marsh	47,064	*
J. E. Addison	25,288	*
S. A. Byrne	26,200	*
R. T. Lindsay	3,260	*
W. K. Kissam	19,453	*
G. E. Aliff	2,829	*
J. A. Bennett	50,418	*
J. F. A. V. Cecil	7,561	*
S. A. Decker	2,895	*
D. M. Hagood	22,399	*
J. M. Micali	36,171	*
L. M. Miller	69,787	*
J. W. Roquemore	42,742	*
M. K. Sloan	66,100	*
A. Trujillo	7,561	*
All executive officers and directors as group (20 persons)	524,604	*

* Less than 1%

(1) Includes shares purchased through February 21, 2017 by the Trustee under the SCANA Corporation 401(k) Retirement Savings Plan.

(2) Includes hypothetical shares acquired under the Director Compensation and Deferral Plan and dividends accrued thereon. These hypothetical shares are paid out in shares and do not have voting rights. As of February 21, 2017, the following directors had acquired the following numbers of hypothetical shares: Messrs. Aliff — 2,829; Bennett — 47,054; Cecil — 2,324; Hagood — 20,989; Micali — 36,171; Roquemore — 28,642; Sloan — 65,575; and Ms. Miller — 65,096.

(3) Hypothetical shares acquired under the Executive Deferred Compensation Plan are not included in the above table. These hypothetical shares are paid out in cash and do not have voting rights. As of February 21, 2017, the following officers and directors had acquired the following numbers of hypothetical shares: Messrs. Marsh — 19,894; Addison — 3,056; Byrne — 30,210; Kissam — 154; and Hagood — 4,507.

(4) Includes shares owned by close relatives and/or shares held in trust for others, as follows: other executive officers as a group — 12,714.

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FIVE PERCENT BENEFICIAL OWNERSHIP OF SCANA COMMON STOCK

The following table provides information about persons known by us to be the beneficial owners of more than five percent of our common stock as of December 31, 2016. Except with respect to the SCANA Corporation 401(k) Retirement Savings Plan and Evercore Trust Company, N.A., this information was obtained from Schedules 13G filed with the Securities and Exchange Commission and we have not independently verified it.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
The Vanguard Group, Inc. 100 Vanguard Boulevard Malvern, PA 19355	13,091,681 (1)	9.16 %
BlackRock, Inc. 55 East 52nd Street New York, NY 10055	12,352,708 (2)	8.60 %
SCANA Corporation 401(k) Retirement Savings Plan Bank of America, N.A., as Trustee 1400 American Boulevard, Third Floor Pennington, NJ 08534 Evercore Trust Company, N.A. 55 East 52nd Street, 36th Floor New York, NY 10055	11,286,237 (3)	7.90 %
State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	7,268,986 (4)	5.09 %

(1)In its most recently filed Schedule 13G, The Vanguard Group, Inc. reported sole voting power with respect to 233,336 shares, shared voting power with respect to 28,184 shares, sole dispositive power with respect to 12,847,038 shares, and shared dispositive power with respect to 244,643 shares.

(2)In its most recently filed Schedule 13G, BlackRock, Inc. reported sole voting power with respect to 11,077,863 shares, sole dispositive power with respect to all 12,352,708 shares, and shared voting and shared dispositive power with respect to no shares.

(3)The SCANA Corporation 401(k) Retirement Savings Plan has shared power to vote and dispose of all of these shares. Participants have the opportunity to give voting instructions to the Plan trustee with respect to shares held in their accounts, and the trustee is required to vote the shares in accordance with such instructions. Shares that are not voted by participants are voted proportionally to the Plan shares voted. Evercore Trust Company, N.A. also has shared dispositive power with respect to all of the same shares in its capacity as independent fiduciary and investment manager for the SCANA Stock Fund under the SCANA Corporation 401(k) Retirement Savings Plan.

(4)In its most recently filed Schedule 13G, State Street Corporation reported sole voting and sole dispositive power with respect to no shares, and shared voting and shared dispositive power with respect to all 7,268,986 shares.

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EXECUTIVE COMPENSATION

Compensation Committee Processes and Procedures

Our Compensation Committee, which is comprised entirely of independent directors, administers our senior executive compensation program. Compensation decisions for all senior executive officers are approved by the Compensation Committee and recommended by the Committee to the full Board for final approval. The Committee considers recommendations from our Chairman and Chief Executive Officer in setting compensation for senior executive officers.

In addition to attendance by members of the Compensation Committee, the Committee's meetings are also regularly attended by our Chairman and Chief Executive Officer, our Senior Vice President of Administration and Human Resources Department employees, as well as management's and the Board's compensation consultants. At each meeting the Committee also meets in executive session without members of management present. The Chairman of the Committee reports the Committee's recommendations on executive compensation to the Board of Directors. Our Human Resources, Tax and Finance Departments support the Compensation Committee in its duties, and the Committee may delegate authority to these departments to fulfill administrative duties relating to our compensation programs.

The Committee has the authority under its Charter to retain, approve fees for, and terminate advisors, consultants and others as it deems appropriate to assist in the fulfillment of its responsibilities. Pursuant to this authority, the Committee engages the services of its own independent compensation consultant, Pearl Meyer & Partners. Management engages the services of Willis Towers Watson as its executive officer and director compensation consultant. In consultation with Pearl Meyer & Partners, the Committee also uses relevant information provided by Willis Towers Watson to assist it in carrying out its responsibilities for overseeing matters relating to compensation plans and compensation of our senior executive officers. Using information provided by Willis Towers Watson, which is a national compensation consultant, helps assure the Committee that our policies for compensation and benefits are competitive and aligned with utility and general industry practices. However, the Committee believes that also engaging its own independent compensation consultant eliminates the appearance of any potential conflict of interest that might arise because management's consultant also performs other services for the Company. Pearl Meyer & Partners does not perform any additional services for the Company.

The Compensation Committee has assessed the independence of Pearl Meyer & Partners pursuant to Securities and Exchange Commission rules and New York Stock Exchange Listing Standards and determined that Pearl Meyer & Partners' work for the Compensation Committee does not raise any conflict of interest.

Compensation Committee Interlocks and Insider Participation

During 2016, decisions on various elements of executive compensation were made by the Compensation Committee. No officer, employee, former officer or any related person of SCANA or any of its subsidiaries served as a member of the Compensation Committee.

The directors who served on the Compensation Committee during 2016 were:

Mr. James A. Bennett (Chairman since April 2016)
Mr. John F. A. V. Cecil
Mrs. Sharon A. Decker
Mr. James M. Micali
Mr. James W. Roquemore
Mr. Maceo K. Sloan (Chairman until April 2016)
Mr. Harold C. Stowe

Compensation Risk Assessment

Our Human Resources, Risk Management, and Legal Departments have jointly reviewed our compensation policies and procedures to determine whether they present a significant risk to the Company. Based on this review we have concluded that our compensation policies and procedures for all employees are not reasonably likely to have a material adverse effect on the Company. Our annual incentive compensation plans for all employees are structured such that appropriate limits are in place to discourage excessive risk taking. In addition, all leadership level employees who are in a position to effect significant policies or projects have compensation at risk on both a short- and long-term basis, which we believe discourages excessive risk taking and encourages supervision of any risk related activities by other employees. Our

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compensation programs and policies, including our senior executive officer share ownership requirements, reward consistent, long-term performance by heavily weighting leadership level compensation to long-term incentives that reward stock, financial, and operating performance. In addition, all of our senior executive officers, who are also members of our Risk Management Committee, oversee and approve individual and business unit objectives for their areas of responsibility so they are positioned to report any risk associated with such individual or business unit objectives to the Risk Management Committee.

Compensation Discussion and Analysis

Objectives and Philosophy of Executive Compensation

Our senior executive compensation program is designed to support our overall objective of increasing shareholder value by:

- Hiring and retaining premier executive talent;
- Having a pay-for-performance philosophy that links total rewards to achievement of corporate, business unit and individual goals, and places a substantial portion of pay for senior executives at risk;
- Aligning the interests of executives with the long-term interests of shareholders through long-term equity-based incentive compensation; and
- Ensuring that the elements of the compensation program focus on and appropriately balance our financial, customer service, operational and strategic goals, all of which are crucial to achieving long-term results for our shareholders.

We have designed our compensation program to reward senior executive officers for their individual and collective performance and for our collective performance in achieving goals for growth in earnings per share and total shareholder return and other annual and long-term business objectives. We believe our program performs a vital role in keeping executives focused on improving our performance and enhancing shareholder value while rewarding successful individual executive performance in a way that helps to assure retention.

The following discussion provides an overview of our compensation program for all of our senior executive officers (for 2016, a group of 11 people who are at the level of senior vice president and above), as well as a specific discussion of compensation for our Chief Executive Officer, our Chief Financial Officer and the other executive officers named in the Summary Compensation Table that follows this “Compensation Discussion and Analysis.” In this discussion, we refer to the executives named in the Summary Compensation Table as “Named Executive Officers.”

Principal Components of Executive Compensation

During 2016, senior executive compensation consisted primarily of three key components: base salary, short-term cash incentive compensation, and long-term equity-based incentive compensation (under the shareholder-approved Long-Term Equity Compensation Plan). We also provide various additional benefits to senior executive officers, including health, life and disability insurance plans, retirement plans, change in control arrangements, limited perquisites, and, if appropriate, severance and termination benefits. The Compensation Committee makes its decisions about how to allocate senior executive officer compensation among base salary, short-term cash incentive compensation and long-term equity-based incentive compensation on the basis of market information and analysis provided by management’s compensation consultant, and our goals of remaining competitive with the compensation practices of a group of surveyed companies and of linking compensation to our corporate performance and individual senior executive officer performance. We also evaluate the market information for specific positions and consider internal equity issues when making pay adjustments. At the Committee’s discretion, information used or provided by management, or provided by management’s compensation consultant to assist the Committee in making its decisions, may be reviewed by the Committee’s independent compensation consultant, Pearl Meyer & Partners.

A more detailed discussion of each of these components of senior executive officer compensation, the reasons for awarding such types of compensation, the considerations in setting the amounts of each component of compensation, the amounts actually awarded for the periods indicated, and various other related matters are set forth in the sections below.

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Factors Considered in Setting Senior Executive Officer Compensation

Use of Market Surveys and Peer Group Data

We believe it is important to consider comparative market information about compensation paid to executive officers of other companies in order to remain competitive in the executive workforce marketplace. We want to attract and retain highly skilled and talented senior executive officers who have the ability to carry out our short- and long-term goals. To do so, we must be able to compensate them at levels that are competitive with compensation offered by other companies in our business or geographic marketplace that seek similarly skilled and talented executives. Accordingly, we consider market survey results in establishing all components of compensation. The market survey information is provided to us approximately every other year by management's compensation consultant. In years in which management's consultant does not provide us with market survey information, and when we require updated information, our process may be to apply an aging factor to the prior year's information with assistance from management's consultant, based on its experience in the marketplace. Compensation decisions for 2016 were based on a compensation survey performed in 2015 by management's compensation consultant, Willis Towers Watson. Prior to management's consultant conducting the market survey, we assist management's consultant in understanding the key duties and responsibilities of our positions, which enables the consultant to match our positions with benchmark positions in its database. If management's consultant is unable to find an exact match for one of our positions in the consultant's database due to variances in duties and/or position level, we may assist management's consultant in identifying the most similar position. The market survey information may then be adjusted upward or downward as necessary to match the position as closely as possible.

Our goal is to set base salary and short- and long-term incentive compensation for our senior executive officers at the median (50th percentile) of compensation paid for similar positions by the companies included in the market surveys. We generally set our target at the median because we believe this target will meet the requirements of most of the persons we seek to hire and retain in our geographic area, and because we believe it is fair both to us and to the executives. Variations to this objective may, however, occur as dictated by the experience level of the individual, internal equity, need for specialized talent, and market factors. We do not set a target level for broad-based benefits for our senior executive officers, but we believe our broad-based benefits are approximately at the median.

The companies included in the market survey are a group of utilities and general industry companies of various sizes in terms of revenue. Approximately half of the companies included in the 2015 market survey had substantially the same levels of annual revenues as we had, while the remainder had revenues ranging from one-third to not greater than 3.8 times our revenues with the exception of the inclusion of three utilities that are geographically close to us and have nuclear operations and are competitors for our talent. Market survey results for positions may be size-adjusted using regression analysis to account for these differences in company revenues, which in turn are viewed as a proxy for measuring the relative scope and complexity of the business operations.

The companies included in the 2015 market survey we used in connection with setting base salaries and short- and long-term incentive compensation for 2016, and the states in which they are headquartered are listed below:

Utility Industry: AGL Resources, Inc. (GA); Alliant Energy Corporation (WI); Ameren Corporation (MO); Avista Corp. (WA); CenterPoint Energy, Inc. (TX); CMS Energy Corporation (MI); Consolidated Edison, Inc. (NY); Dominion Resources, Inc. (VA); Duke Energy Corporation (NC); Edison International (CA); Entergy Corporation (LA); Eversource Energy (CT); MDU Resources Group, Inc. (ND); NextEra Energy, Inc. (FL); OGE Energy Corporation (OK); Pepco Holdings, Inc. (DC); Pinnacle West Capital Corporation (AZ); Portland General Electric Co. (OR); Public Service Enterprise Group, Inc. (NJ); Sempra Energy (CA); Southern Company (GA); TECO Energy, Inc. (FL); UIL Holdings Corporation (CT); Vectren Corporation (IN); WEC Energy Group (WI); Westar Energy, Inc. (KS); Xcel Energy, Inc. (MN).

General Industry: Armstrong World Industries, Inc. (PA); Ball Corporation (CO); Curtiss-Wright, (NC); Eastman Chemical Company (TN); Hanesbrands, Inc. (NC); The Hershey Company (PA); Level 3 Communications, Inc. (CO); Mattel, Inc. (CA); Pitney Bowes, Inc. (CT); PolyOne Corporation, (OH); Rockwell Automation, Inc. (WI); Rockwell Collins, Inc. (IA); Sealed Air Corporation (NJ); Snap-on, Inc. (WI); Steelcase Inc. (MI); Terex Corporation (CT); The Scotts Miracle-Gro Company (OH); Tupperware Brands, (FL); Unisys Corporation (PA); WestRock Company (VA).

We believe the utilities included in our market survey are an appropriate group to use for compensation comparisons because they align well with our revenues (other than three utilities included because they are geographically close to us, have nuclear operations and are competitors for our talent), the nature of our business and workforce, and the talent and skills required for safe and successful operations. We believe the additional non-utility companies included in our market

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survey are appropriate to include in our comparisons because they align well with our revenues, and are the types of companies that might be expected to seek executives with the same general skills and talents as the executives we are trying to attract and retain in our geographic area. The companies we use for comparisons may change from time to time based on the factors discussed above as well as their participation in the consultant's executive compensation surveys.

To make comparisons with the market survey results, we generally divide all of our senior executive officers into utility and non-utility executive groups — that is, executive officers whose responsibilities are primarily related to utility businesses and require a high degree of technical or industry-specific knowledge (such as electrical engineering, nuclear engineering or gas pipeline transmission), and those whose responsibilities are more general and do not require such specialized knowledge (such as business, finance, and other corporate support functions). We then attempt to match to the greatest degree possible our positions with similar positions in the survey results. We may blend the survey results to achieve what we believe is an appropriate comparison.

We also use performance data covering a larger peer group of utilities in determining long-term equity incentive compensation under our shareholder-approved Long-Term Equity Compensation Plan, as discussed under "Long-Term Equity Compensation Plan."

Personal Qualifications

In addition to considering market survey comparisons, we consider each senior executive officer's knowledge, skills, scope of authority and responsibilities, job performance and tenure with us as a senior executive officer.

Mr. Marsh has been our Chairman and Chief Executive Officer since December 2011, and he has also served as our President and Chief Operating Officer since January 2011. Prior to January 2011, he served as our Senior Vice President from 1998 to January 2011, and as our Chief Financial Officer from 1996 to April 2006. He previously served as President of South Carolina Electric & Gas Company ("SCE&G"), our largest subsidiary from April 2006 to November 2011, and as SCE&G's Chief Operating Officer from April 2006 to January 2011. Mr. Marsh previously practiced as a certified public accountant and has been with us for over 30 years. As our Chief Executive Officer, Mr. Marsh is responsible for strategic planning, development of our senior executive officers and oversight of our operations.

Mr. Addison was appointed Executive Vice President of SCANA in January 2012, and he has served as our Chief Financial Officer since April 2006. Additionally, in May 2014, Mr. Addison was appointed President and Chief Operating Officer of our subsidiary, SCANA Energy Marketing, Inc. Prior to January 2012, Mr. Addison had served as a Senior Vice President of SCANA since 2006 and Vice President of Finance from 2001 to 2006. As Chief Financial Officer, he is responsible for all of our financial operations, including accounting, treasury, shareholder and investor relations, taxation and financial planning, and until November of 2016, he was responsible for senior oversight of our information technology functions. Mr. Addison is also a certified public accountant and has been with us for more than 25 years.

Mr. Byrne is an Executive Vice President of SCANA, as well as President of Generation and Transmission and Chief Operating Officer of SCE&G. In these positions he is responsible for overseeing a diversified fleet of coal, natural gas, hydro, nuclear and renewable generating facilities as well as the operation and planning of our high voltage transmission system. His nuclear responsibilities include overseeing the construction of our two new nuclear units. He was previously our Chief Nuclear Officer. He is a degreed engineer with over 30 years of utility experience and has held a Nuclear Regulatory Commission Senior Reactor Operator's license. Mr. Byrne has been with us for over 20 years.

Mr. Lindsay is a Senior Vice President and the General Counsel of SCANA and its subsidiaries. He is responsible for oversight of all legal, legal regulatory, environmental, and corporate secretary functions. Mr. Lindsay has been with us for 8 years and has more than 40 years experience as an attorney, which includes more than 25 years serving in a General Counsel role.

Mr. Kissam is a Senior Vice President of SCANA, as well as the President of Retail Operations for SCE&G. In these positions he is responsible for providing leadership and strategic planning for the safe and reliable construction, maintenance, and operations of our electric transmission and distribution systems. He also oversees the Company's renewable energy initiatives. Mr. Kissam has been with us for 29 years.

Other Factors Considered

In addition to the foregoing information, we consider the fairness of the compensation paid to each senior executive officer in relation to what we pay our other senior executive officers. Our Compensation Committee also considers

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recommendations from our Chairman and Chief Executive Officer in setting compensation for senior executive officers. We review our compensation program and levels of compensation paid to all of our senior executive officers, including the Named Executive Officers, annually and may make adjustments based on the foregoing factors as well as other subjective factors.

In 2016, our Compensation Committee reviewed summaries of compensation components ("tally sheets") for all of our senior executive officers, including the Named Executive Officers. These tally sheets reflect changes in compensation during the prior year, if any, and affix dollar amounts to each component of compensation. Although the Committee did not make any adjustments to executive compensation in 2016 based solely on its review of the tally sheets, it intends to continue to use such tally sheets in the future to review each component of the total compensation package, including base salaries, short- and long-term incentives, severance plans, insurance, retirement and other benefits, as a factor in determining the total compensation package for each senior executive officer.

The Committee does not have a practice of adjusting the size of current and future compensation awards or compensation program components to reflect amounts realized or unrealized by an individual from prior equity grants. In other words, awards are not increased to compensate for prior performance below target, nor are they decreased because of prior performance above target. Likewise, since earnings on equity compensation are not included in any pension calculation formula, any gains, or lack thereof, from prior awards are not considered in setting or earning retirement benefits.

Timing of Senior Executive Officer Compensation Decisions

Annual salary reviews are routinely conducted and any adjustments are made, and short- and long-term incentive compensation awards are routinely granted in February of each year at the first regularly scheduled Compensation Committee and Board meetings. Determinations are also made at those meetings as to whether to pay out awards under the most recently completed cycle of short- and long-term incentive compensation (which include equity based incentive compensation). Compensation determinations also may be made by the Committee at its other quarterly meetings in the case of newly hired executives, employee promotions, or adjustments of existing employees' compensation that could not be deferred until the February meeting. We routinely release our annual and quarterly earnings information to the public in conjunction with the quarterly meetings of our Board.

Base Salaries

Senior executive officer base salaries are divided into grade levels based on market data for similar positions, experience and certain internal equity considerations. The Compensation Committee believes it is appropriate to set base salaries at a reasonable level that will provide executives with a predictable income base. Accordingly, base salaries are targeted at the median (50^{th} percentile) of the market survey data with the exception of Mr. Marsh's salary, which is targeted at the 75^{th} percentile. The Compensation Committee reviews base salaries annually and makes adjustments, if appropriate, on the basis of an assessment of individual performance, relative levels of accountability, prior experience, breadth and depth of knowledge, specialized talent required for new operational initiatives, changes in market compensation practices as reflected in market survey data, and relative compensation levels within our Company. In February 2016, the Named Executive Officers received base salary increases in the following percentages: Mr. Marsh, 5%; Mr. Addison, 5%; Mr. Byrne, 5%; Mr. Lindsay, 3%; and Mr. Kissam, 4%. Such increases were based on individual performance and the degree to which the Named Executive Officers' base salaries were below the market rate for their positions and certain internal equity considerations.

Short-Term and Long-Term Incentive Compensation

Our senior executive officer compensation program provides for both short-term incentive compensation in the form of annual cash incentive compensation, and long-term equity-based incentive compensation payable at the end of periods which have historically lasted three years. Both our Short-Term Annual Incentive and Long-Term Equity Compensation Plans promote our pay-for-performance philosophy, as well as our goal of having a meaningful amount of pay at-risk, and we believe both plans provide us a competitive advantage in recruiting and retaining top quality talent.

We believe the Short-Term Annual Incentive Plan provides our senior executive officers with an annual stimulus to achieve short-term individual and business unit or departmental goals and short-term corporate earnings goals that ultimately help us achieve our long-term corporate goals. We believe the Long-Term Equity Compensation Plan counterbalances the emphasis of short-term incentive compensation on short-term results by focusing our senior executive officers on achievement of our long-term corporate goals, providing additional incentives for them to remain our employees by ensuring that they have a continuing stake in the long-term success of the Company, and significantly aligning the interests of senior executive officers with those of our shareholders.

2015 Changes to Short-Term and Long-Term Incentive Compensation Plans

As discussed in the Company's 2015 and 2016 Proxy Statements, in July of 2014, our Compensation Committee asked management to engage its compensation consultant, Willis Towers Watson, to review our short-term annual incentive and our long-term equity compensation practices for comparability to executive compensation practices of our utility and general industry peers and general compensation best practices. Based on this review, Willis Towers Watson concluded that our executive compensation practices were generally in line with our peers', with a few exceptions. The Compensation Committee reviewed these exceptions, and recommended to the Board a number of changes for the executive compensation awards to be granted in 2015 from the awards granted over the past several years. Willis Towers Watson advised management that these changes would bring our practices more in line with our peers' and current market practices.

These changes, which were implemented in 2015, included revising short-term annual incentive awards to equalize weighting of earnings per share goals and individual goals and to reduce the amount of discretionary award that can be paid, and revising long-term equity compensation awards to change the measurement of the performance cycles, increase the maximum payout, and change the mix of performance shares and restricted stock units. Because the 2014-2016 Long-Term Incentive Compensation Plan awards were granted in February 2014, prior to implementation of the changes, the changes are not reflected in those awards.

Short-Term Annual Incentive Plan

Our Short-Term Annual Incentive Plan provides financial incentives for performance in the form of opportunities for annual incentive cash payments. Participants in the Short-Term Annual Incentive Plan currently include not only our senior executive officers, but also approximately 250 additional employees, including other officers, senior management, division heads and other professionals whose positions or levels of responsibility make their participation in the Plan appropriate. Our Chief Executive Officer recommends, and the Compensation Committee approves, the performance measures, operational goals and other terms and conditions of incentive awards for senior executive officers, including the Named Executive Officers, except the Chief Executive Officer, for whom such determinations are made by the Committee along with the other independent directors.

The Compensation Committee reviews and approves target short-term incentive awards at its first regularly scheduled meeting each year based on percentages assigned to each executive salary grade. Payouts of actual short-term incentive awards are based both on the Company's achieving pre-determined earnings per share goals in the coming year, and on each senior executive officer's level of performance in achieving his or her individual and business unit financial and strategic objectives. The Committee selected these performance metrics because it believes they are key measures of financial and operational success, and that achieving our earnings and strategic goals supports the interests of our shareholders. In assessing accomplishment of objectives, the Committee considers the difficulty of achieving each objective, unforeseen obstacles or favorable circumstances that might have altered the level of difficulty in achieving the objective, overall importance of the objective to our long-term and short-term goals, and importance of achieving the objective to enhancing shareholder value. Changes in annual target short-term incentive awards can be made if there are changes in the senior executive officer's salary grade level or a change in the competitive market target that warrant a target change.

For 2016, the awards under the Short-Term Annual Incentive Plan provided that:

- 50% of the target annual cash incentive award would be earned based on the extent to which we met designated earnings per share goals; and

- 50% of the target award would be earned based on our Named Executive Officers and the other participants' achieving individual and business unit performance objectives. The Committee reviewed and approved all senior executive officer individual and business unit objectives, and the Committee, along with the other independent directors, approved the Chief Executive Officer's individual and business unit objectives.

Payouts of awards are scaled based on the levels at which these goals are met. The 2016 Short-Term Annual Incentive Plan further provided that, if we exceeded our earnings per share goals, payouts of up to 130% of the target awards could be earned, which would also be scaled based on the extent to which we exceeded such earnings per share goals. See "—

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Above Target Awards Earned Based on Exceeding the Earnings per Share Goals of the 2016 Annual Incentive Award" beginning on page 32. The Short-Term Annual Incentive Plan also allows discretionary awards up to 20% of target awards, not to exceed a total award of 150% of target for any participant. See "—Discretionary Bonus Awards" beginning on page 33.

The estimated possible payouts that could have been earned under the 2016 Short-Term Annual Incentive Plan if performance objectives were met at threshold, target and maximum levels are set forth in the "2016 Grants of Plan-Based Awards" table on page 43 under the columns beneath the caption "Estimated Possible Payouts under Non-Equity Incentive Plan Awards." The 2016 payouts under the Short-Term Annual Incentive Plan based on our achieving our earnings per share goal, and our Named Executive Officers' achieving their individual and business unit objectives, are reflected in the "Summary Compensation Table" on page 42, under the column "Non-Equity Incentive Plan Compensation."

Earnings per Share Component of the 2016 Annual Incentive Award

Up to 50% of the total 2016 annual incentive award could be earned based on the extent to which we met our earnings per share goals as set forth below:

Earnings per share	Payout (as % of target award)
$3.90	10%
$3.91	14%
$3.92	18%
$3.93	22%
$3.94	26%
$3.95	30%
$3.96	34%
$3.97	38%
$3.98	42%
$3.99	46%
$4.00	50%

Our actual earnings per share for 2016 were $4.16, which resulted in our senior executive officers, and the other participants in the Short-Term Annual Incentive Plan, earning 100% on the 50% of the earnings per share component of the 2016 annual incentive award.

Individual Strategic Objectives Component of 2016 Annual Incentive Award

The remaining 50% of the 2016 annual incentive award was based on our senior executive officers' level of performance in helping us achieve our annual business objectives by achieving their individual and business unit performance objectives. All of our Named Executive Officers achieved all of their individual and business unit financial and strategic objectives in 2016. Accordingly, our Named Executive Officers earned 100% on the 50% portion of the annual incentive award based on individual and business unit performance.

Individual Strategic Objectives on which 2016 Annual Incentive Awards were Based

All of our Named Executive Officers were responsible for specific financial metrics to support the Company's earnings per share goals as well as prioritization of actions under, and commencing implementation of, plans to support the Company's workforce diversity objectives. Specifically, each Named Executive Officer was required to contribute to the Company's objective to meet an earnings per share growth target. The financial metric also required the identification of additional pre-tax income for 2017.

In addition to the common goals as set forth above, the individual and business unit strategic objectives the Compensation Committee considered in determining short-term incentive awards for the Named Executive Officers were as follows:

Mr. Marsh's award was based on his oversight and support of our new nuclear construction activities, as well as providing leadership to senior executive officers to ensure successful completion of major 2016 corporate initiatives.

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Mr. Addison's award was based on his efforts to secure financing related to our new nuclear construction project; completing an evaluation of pricing options under the amended Engineering, Procurement and Construction Agreement relating to our new nuclear construction, and overseeing regulatory approval of additional costs associated with the selected option; and evaluating, in consultation with external advisors and credit rating agencies, the benefit of various tax initiatives, and based on the evaluation, the implementation of appropriate initiatives.

Mr. Byrne's award was based on his continuing oversight of various aspects of our new nuclear construction activities; completing an evaluation of pricing options under the amended Engineering, Procurement and Construction Agreement relating to our new nuclear construction, and overseeing regulatory approval of additional costs associated with the selected option; and obtaining a long-term coal ash sale agreement and regulatory approvals in connection therewith.

Mr. Lindsay's award was based on his oversight of our sustainability efforts as articulated in our Environmental Sustainability Report; his involvement in implementation of the amended Engineering, Procurement and Construction Agreement relating to our new nuclear construction and establishment of a Dispute Resolution Board to resolve pricing disputes under the agreement; and his involvement in our response to proposed environmental regulations.

Mr. Kissam's award was based on his oversight of our achieving specific safety and customer reliability goals for electric operations; developing and overseeing completion of our new nuclear transmission construction milestones; and developing and providing executive leadership for the implementation of a comprehensive community outreach plan.

Above Target Awards Earned Based on Exceeding the Earnings per Share Goals of the 2016 Annual Incentive Award

As discussed in the foregoing sections, all of our Named Executive Officers earned 100% of their target awards under the 2016 Short-Term Annual Incentive Plan, based 50% on our achieving our earnings per share goals and 50% on their meeting individual and business unit objectives.

In addition to the 50% of the awards earned based on earnings per share and the 50% of the awards earned based on results of individual and business unit strategic objectives, our 2016 Short-Term Annual Incentive Plan provided that awards of up to 130% of target could be earned if earnings per share goals exceeded the target of $4.00 as set forth below:

Earnings per share	Payout (as % of target award)
$4.00	100%
$4.01	103%
$4.02	106%
$4.03	109%
$4.04	112%
$4.05	115%
$4.06	118%
$4.07	121%
$4.08	124%
$4.09	127%
$4.10	130%

Our actual earnings per share for 2016 were $4.16, which resulted in our senior executive officers, and the other participants in the Short-Term Annual Incentive Plan, earning 130% of target awards.

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Discretionary Bonus Awards

Our Short-Term Annual Incentive Plan also allows for discretionary awards as may be recommended by our Compensation Committee and approved by our full Board (or all independent directors in the case of the Chief Executive Officer) up to 20% of target awards. The discretion may be applied for all or for individual participants, but no participant's award may exceed 150% of the participant's target award.

Our Board also has the discretion to decrease any or all awards made pursuant to the Short-Term Annual Incentive Plan.

During 2016, our Board did not make any discretionary awards, or decrease any awards, to any Named Executive Officers in the Short-Term Annual Incentive Plan.

Long-Term Equity Compensation Plan

The potential value of long-term equity-based incentive compensation opportunities comprises a significant portion of the total compensation package for senior executive officers and key employees. The Compensation Committee believes that emphasizing this component of total compensation provides the appropriate long-range focus for senior executive officers and other key employees who are charged with responsibility for managing the Company and achieving success for our shareholders because it links the amount of their compensation to our long-term business and financial performance.

A portion of each senior executive officer's potential compensation consists of awards under the Long-Term Equity Compensation Plan. The types of long-term equity-based compensation the Compensation Committee may award under the Plan include incentive and non-qualified stock options, stock appreciation rights (either alone or in tandem with a related stock option), restricted stock, restricted stock units, performance units and performance shares. In recent years, our long-term equity-based awards have been in the form of performance shares and restricted stock units. These long-term equity-based awards are granted subject to satisfaction of specific performance goals and vesting schedules. For the 2014-2016 performance period, awards under the Long-Term Equity Compensation Plan consisted of 80% performance shares and 20% restricted stock units. For the 2015-2017 and 2016-2018 performance periods, awards under the Long-Term Equity Compensation Plan consisted of 70% performance shares and 30% restricted stock units. The Committee has not awarded stock options since 2002 and has no plans to do so in the foreseeable future, and the Committee has not awarded any stock appreciation rights under the Plan.

We believe awards of performance shares align the interests of our executives with those of shareholders because the value of such awards is tied to our achieving financial and business goals that would be expected to affect the value of our common stock. We believe awards of restricted stock units align the interests of our executives with those of shareholders in that they ensure a long-term view of success, and we believe the three-year vesting schedule aids in retention of executives. Although restricted stock units do not have the same risk of forfeiture for failure to meet performance thresholds associated with performance shares, they have no upside potential for payout above target level.

Performance Share Awards

For several years prior to 2015, the Compensation Committee granted performance share awards that were earned, if at all, over a three-year period measured in three one-year cycles based on comparative Total Shareholder Return ("TSR") and earnings per share growth components. Beginning with grants made in February 2015, however, the three-year periods are measured in a single three-year cycle. Performance share awards based on these components place a portion of executive compensation at risk because executives are compensated pursuant to the awards only when the objectives for TSR and earnings growth are met. Additionally, comparing our TSR to the TSR of a group of other companies reflects our recognition that investors could have invested their funds in other entities and measures how well we performed over time when compared to others in the group.

Performance share awards are denominated in shares of our common stock. The number of target performance shares into which awards are denominated is calculated by multiplying the Named Executive Officer's base salary by a target percentage based on positions cited in the market survey data and dividing the product by a valuation factor applied to our opening stock price on the date of grant. The target percentage is derived from market survey data of the peer companies listed above under "Factors Considered in Setting Senior Executive Officer Compensation — Use of Market Surveys and Peer Group Data." The valuation factor is provided to us by management's compensation consultant and is intended as a means to establish a grant date salary equivalent value that takes into consideration such factors as dividend treatment,

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and potential for maximum performance. Performance share awards may be paid in stock or cash or a combination of stock and cash at the Committee's discretion, but are most frequently paid in cash. In recent years, all payouts have been in cash. Payouts are based on the closing market price of our stock on the last business day of the three-year performance period. Performance share awards accrue dividend equivalents prior to vesting, which are paid at vesting based on the level at which the awards are earned.

2014-2016 Performance Share and Restricted Stock Unit Awards

For the 2014-2016 period, we granted awards under the Long-Term Equity Compensation Plan to each of the Named Executive Officers comprised of a combination of 80% performance shares and 20% restricted stock units.

Components of 2014-2016 Performance Share Awards

For the 2014-2016 period, the components on which we based performance share awards to senior executive officers were as follows: (1) one half to be earned based on our level of achieving TSR relative to the TSR of a peer group of companies; and (2) remaining one half to be earned based on our level of achieving growth in "GAAP-adjusted net earnings per share" targets.[1] TSR over each of the one-year performance periods was equal to the change in our common stock price, plus cash dividends paid on our common stock during the period, divided by the common stock price as of the beginning of the period.

Performance measurement and award determinations for the performance shares for the 2014-2016 period were made on an annual basis with vesting and payment of awards being deferred until after the end of the three-year period. Accordingly, payouts under the 2014-2016 three-year period were earned for each year that performance goals were met during the three-year period, but vesting and payment were deferred until the end of the three-year period and were contingent upon the participant still being employed with us at the end of the three-year period, subject to certain exceptions in the event of retirement, death or disability. Payouts would also have been accelerated in the event of certain change in control events. See " — Potential Payments Upon Termination or Change in Control."

Performance Criteria for the 2014-2016 Performance Share Awards and Earned and Vested Awards for the 2014-2016 Performance Period

For the half of the 2014-2016 performance share awards based on the TSR component, payouts were scaled according to our ranking against a peer group of utilities. Executives could earn threshold payouts (equal to 25% of target award) for each year of the three-year period in which we ranked at the 25th percentile in relation to the peer group's TSR performance for the one-year cycle. Target payouts (equal to 100% of target award) could be earned for each year of the three-year period in which we ranked at the 50th percentile in relation to the peer group's TSR performance for the one-year cycle. Maximum payouts (equal to 175% of target award) could be earned for each year of the three-year period in which our performance ranked at or above the 90th percentile in relation to the peer group's TSR performance for the one-year cycle. Payouts were scaled between 25% and 175% of target based on the actual percentile achieved. No payout could be earned if our performance was less than the 25th percentile, and no payouts could exceed 175% of the target award. Threshold, target and maximum payouts at the 25th, 50th and 90th percentiles were used because these generally matched the levels used by the companies in the market survey data.

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[1] "GAAP-adjusted net earnings per share," and "GAAP-adjusted weather-normalized net earnings per share," as used throughout this proxy statement, are synonymous terms that we have used over time in our periodic reports and external communications to refer to the same non-GAAP financial measure. We believe that this non-GAAP financial measure provides a consistent basis upon which to measure performance from year to year. The measure has historically excluded from earnings such items as the effects arising from abnormal weather, the Company's adoption of new accounting guidance, the favorable settlement of certain litigation, and the effects of sales of certain investments. Management uses this measure when determining earnings guidance and growth projections and uses the measure in part in making budgetary and operational decisions. During 2014, our GAAP-adjusted weather-normalized net earnings per share of $3.58 were lower than our GAAP net earnings per share of $3.79 due to the exclusion of $0.21 ($0.31 pre-tax less a tax effect of $0.10) attributable to the effects of abnormal weather in the Company's electric business. During 2015, our GAAP-adjusted weather-normalized net earnings of $3.73 were lower than our GAAP net earnings per share of $5.22 due to the exclusion of $1.41 ($2.39 pre-tax less a tax effect of $0.98) attributable to the sales of two subsidiaries and $0.08 ($0.12 pre-tax less a tax effect of $0.04) attributable to the effects of abnormal weather in the Company's electric business. During 2016, our GAAP-adjusted weather-normalized net earnings per share of $3.97 were lower than our GAAP net earnings per share of $4.16 due to the exclusion of $0.19 ($0.28 pre-tax less a tax effect of $0.09) attributable to the effects of abnormal weather in the Company's electric business.

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The peer group of utilities with which we compared our TSR for the 2014-2016 period are set forth below:

Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Avista Corporation; CenterPoint Energy Inc.; CMS Energy Corporation; Consolidated Edison, Inc.; Dominion Resources, Inc.; DTE Energy Company; Duke Energy Corporation; Edison International; Entergy Corporation; Exelon Corporation; FirstEnergy Corp.; Great Plains Energy, Inc.; Hawaiian Electric Industries, Inc.; Integrys Energy Group, Inc.; NextEra, Inc.; NiSource Inc.; Northeast Utilities; NorthWestern Corporation; NV Energy; OGE Energy Corp.; Pepco Holdings, Inc.; PG&E Corporation; Pinnacle West Capital Corporation; PNM Resources, Inc.; PPL Corporation; Public Service Enterprise Group, Inc.; Southern Company; TECO Energy, Inc.; UIL Holdings Corporation; UNS Energy Corporation; Vectren Corporation; Westar Energy, Inc.; Wisconsin Energy Corporation; XCEL Energy, Inc.

The number of utilities included in the peer group used for TSR comparisons is larger than the number included in the market survey utility peer group we use for purposes of setting base salary and short- and long-term incentive targets because information about TSR is publicly available for a larger number of utilities. We include only utilities in the TSR peer group because we have assumed that shareholders would measure our performance against performance of other utilities in which they might have invested.

For the first, second and third years of the 2014-2016 performance period, our TSR was at the 61st, 82nd, and 75th percentiles, which resulted in 121% being earned on the TSR component for the first year, 160% being earned for the second year, and 147% for the third year, vesting and payment of which were deferred until the end of the three-year period as discussed above. The overall payout of the TSR portion of the performance shares, which occurred in February 2017, was 142.67%.

For the half of performance shares based on our level of achieving growth in GAAP-adjusted net earnings per share targets, executives could earn threshold payouts (equal to 25% of target award) for each year in the three-year period in which growth in GAAP-adjusted net earnings per share equaled 1%. Executives could earn target payouts (equal to 100% of target award) for each year in which such growth equaled 4.5%, and maximum payouts (equal to 175% of target award) for each year in which such growth equaled or exceeded 8%. Potential payouts were scaled between 25% and 175% based on the actual growth in GAAP-adjusted net earnings per share. No payouts could be earned for any year in which growth in GAAP-adjusted net earnings per share was less than 1%, and no payouts could exceed 175% of target award.

For the first, second and third years of the 2014-2016 period, our growth in GAAP-adjusted net earnings per share was 5.3%,4.2%, and 6.4%, respectively (11.5%, 37.7% and 20.3% respectively, in GAAP net earnings per share (see footnote 1 on page 34 for a reconciliation of our GAAP-adjusted net earnings per share to our GAAP net earnings per share)), which resulted in 117.1%, 93.6%, and 140.7% awards on the earnings per share component being earned for the first, second and third years, respectively, vesting and payment of which were deferred until the end of the three-year period as discussed above. The overall payout of the GAAP-adjusted net earnings per share portion of the performance shares, which occurred in February 2017, was 117.13%.

The overall payout of the total TSR and GAAP-adjusted net earnings per share components of the performance share awards for the 2014-2016 cycle, which occurred in February 2017, was 129.9%, and is reflected in the "2016 Option Exercises and Stock Vested" table on page 45.

2014-2016 Restricted Stock Unit Awards

The 2014-2016 restricted stock unit awards were granted on February 20, 2014, and were based on the fair market value of our common stock on the date of grant. The restricted stock units were subject to a three-year vesting period, and were not performance based. The restricted stock units did not have voting rights prior to vesting, and were subject to forfeiture in the event of termination of employment prior to the end of the vesting period, subject to exceptions for retirement, death, disability, or change in control. The restricted stock units accrue dividend equivalents prior to vesting. Information about vesting of the restricted stock unit award component of the 2014-2016 awards is reflected in the "2016 Option Exercises and Stock Vested" table on page 45. The restricted stock units were paid in cash in February 2017.

2015-2017 Performance Share and Restricted Stock Unit Awards

As discussed above, in 2015 the Compensation Committee recommended, and the Board approved, a number of changes to our long-term incentive compensation practices to better align them with peer companies. These changes included revising long-term equity compensation awards to change the measurement of performance cycles, increase the maximum payout, and change the mix of performance shares and restricted stock units.

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For the 2015-2017 period, we changed the mix of awards granted under the Long-Term Equity Compensation Plan to each of the Named Executive Officers from a combination of 80% performance shares and 20% restricted stock units to a combination of 70% performance shares and 30% restricted stock units.

Components of 2015-2017 Performance Share Awards

The components on which we based the 2015-2017 performance share awards were as follows: (1) one half to be earned based on our level of achieving TSR relative to the TSR of a peer group of companies; and (2) the remaining one half to be earned based on our level of achieving average growth in GAAP-adjusted weather-normalized net earnings per share targets. Using a 20 trading day average prior to the start and end of the performance period, the TSR over the performance period will be equal to the change in our common stock price, plus cash dividends paid on our common stock during the period, divided by the common stock price as of the beginning of the period. Unlike the 2014-2016 performance share awards, performance measurement and award determination for the performance shares for the 2015-2017 period will be made for the entire three-year cycle with vesting and payment of awards after the end of the three-year cycle, instead of performance measurement and award determination being made on an annual basis with vesting and payment of awards being deferred until after the end of the three-year period.

Performance Criteria for the 2015-2017 Performance Share Awards

Payouts based on the TSR component of the 2015-2017 performance share awards will be scaled according to our ranking against the same peer group of utilities used for the 2014-2016 period as discussed above under "Performance Criteria for the 2014-2016 Performance Share Awards and Earned and Vested Awards for the 2014-2016 Performance Period," unless a company could no longer be included due to a merger, dissolution or other similar transaction.

Executives can earn threshold payouts (equal to 25% of target award) if our TSR for the entire three-year period ranks at the 25th percentile in relation to the peer group's TSR performance for the three-year period. Target payouts (equal to 100% of target award) can be earned if our TSR for the entire three-year period ranks at the 50th percentile in relation to the peer group's TSR performance for the three-year period. Maximum payouts (equal to 200% of target award) can be earned if our TSR for the entire three-year period ranks at or above the 90th percentile in relation to the peer group's performance for the three-year period. Payouts will be scaled between 25% and 200% based on the actual percentile achieved for the three-year period. No payout can be earned if our performance over the three-year period is less than the 25th percentile, and no payout can exceed 200% of the target award. Threshold, target and maximum payouts at the 25th, 50th and 90th percentiles were used because these generally matched the levels used by the companies in the market survey data.

For the half of performance shares based on our level of achieving growth in GAAP-adjusted weather-normalized net earnings per share targets, we will determine the growth achieved by calculating GAAP-adjusted weather-normalized net earnings per share for each year in the three-year period and averaging the amounts. Executives can earn threshold payouts (equal to 25% of target award) if for the three-year period, average annual growth in GAAP-adjusted weather-normalized net earnings per share equals 1%. Executives can earn target payouts (equal to 100% of target award) if for the three-year period, such average annual growth equals 4.5%, and maximum payouts (equal to 200% of target award) if for the three-year period, such average annual growth equals or exceeds 8%. Potential payouts will be scaled between 25% and 200% based on the actual average growth in GAAP-adjusted weather-normalized net earnings per share for the entire three-year period. No payouts can be earned if growth in GAAP-adjusted weather-normalized net earnings per share is less than 1% for the three-year period, and no payouts can exceed 200% of target award.

See "Outstanding Equity Awards at 2016 Fiscal Year-End" table on page 44 for information about performance share awards outstanding at the end of 2016.

2015-2017 Restricted Stock Unit Awards

The 2015-2017 restricted stock unit awards were granted on February 19, 2015, and were based on the fair market value of our common stock on the date of grant. The restricted stock units are subject to a three-year vesting period, and are not performance based. The restricted stock units have the same terms as the 2014-2016 restricted stock units as discussed above under "2014-2016 Restricted Stock Unit Awards." Information about the outstanding restricted stock unit awards granted for the 2015-2017 three-year period is provided in the "Outstanding Equity Awards at 2016 Fiscal Year-End" table on page 44.

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2016-2018 Performance Share and Restricted Stock Unit Awards

For the 2016-2018 period, we again granted awards under the Long-Term Equity Compensation Plan to each of the Named Executive Officers comprised of a combination of 70% performance shares and 30% restricted stock units.

Components of 2016-2018 Performance Share Awards

The components on which we based the 2016-2018 performance share awards and the TSR measurement for the 2016-2018 performance share awards are the same as for the 2015-2017 awards. Like the 2015-2017 performance share awards, performance measurement and award determination for the performance shares for the 2016-2018 period will be made for the entire three-year cycle with vesting and payment of awards after the end of the three-year cycle. See "—Components of 2015-2017 Performance Share Awards" on page 36.

Performance Criteria for the 2016-2018 Performance Share Awards

Payouts based on the TSR component of the 2016-2018 performance share awards will be scaled according to our ranking against the same peer group of utilities used for the 2014-2016 and 2015-2017 periods as discussed above under "Performance Criteria for the 2014-2016 Performance Share Awards and Earned and Vested Awards for the 2014-2016 Performance Period," and "Performance Criteria for the 2015-2017 Performance Share Awards," unless a company could no longer be included due to a merger, dissolution or other similar transaction.

For the half of performance shares based on our level of achieving growth in GAAP-adjusted weather-normalized net earnings per share targets, we will determine the growth achieved by calculating GAAP-adjusted weather-normalized net earnings per share for each year in the three-year period and averaging the amounts. Executives can earn threshold payouts (equal to 25% of target award) if for the three-year period, average annual growth in GAAP-adjusted weather-normalized net earnings per share equals 1%. Executives can earn target payouts (equal to 100% of target award) if for the three-year period, such average annual growth equals 5%, and maximum payouts (equal to 200% of target award) if for the three-year period, such average annual growth equals or exceeds 9%. Potential payouts will be scaled between 25% and 200% based on the actual average growth in GAAP-adjusted weather-normalized net earnings per share for the entire three-year period. No payouts can be earned if growth in GAAP-adjusted weather-normalized net earnings per share is less than 1% for the three-year period, and no payouts can exceed 200% of target award.

See the "2016 Grants of Plan-Based Awards" table on page 43 for information about 2016 grants of performance share awards, and "Outstanding Equity Awards at 2016 Fiscal Year-End" table on page 44 for information about performance share awards outstanding at the end of 2016.

2016-2018 Restricted Stock Unit Awards

The 2016-2018 restricted stock unit awards were granted on February 18, 2016, and were based on the fair market value of our common stock on the date of grant. The restricted stock units are subject to a three-year vesting period, and are not performance based. The restricted stock units have the same terms as the 2014-2016 and 2015-2017 restricted stock units as discussed above under "2014-2016 Restricted Stock Unit Awards" and "2015-2017 Restricted Stock Unit Awards." Information about the restricted stock unit awards granted for the 2016-2018 three-year period is provided in the "2016 Grants of Plan-Based Awards" table on page 43. See also the "Outstanding Equity Awards at 2016 Fiscal Year-End" table on page 44.

Other 2017 Compensation Decisions

At its February 2017 meeting, the Board, on recommendation of the Compensation Committee, increased the base salaries of Messrs. Marsh (4%), Addison (4%), Byrne (4%), Kissam (4%), and Lindsay (3%). The salary adjustments will not result in compensation materially different from 2016 compensation.

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Retirement and Other Benefit Plans

We currently sponsor the following retirement benefit plans:

- A tax qualified defined benefit retirement plan (the "Retirement Plan") *(closed to new employees and rehired employees as of December 31, 2013)*;
- A nonqualified defined benefit Supplemental Executive Retirement Plan (the "SERP") *(closed to new employees and rehired employees as of December 31, 2013)*;
- A tax qualified defined contribution plan (the "401(k) Plan" also known as the "SCANA Corporation 401(k) Retirement Savings Plan"); and
- A nonqualified defined contribution Executive Deferred Compensation Plan (the "EDCP").

All employees who have met eligibility requirements may participate in the Retirement Plan and the 401(k) Plan.

The SERP and the EDCP are designed to provide a benefit to senior executive officers who participate in the Retirement Plan or 401(k) Plan (our tax qualified retirement plans) and whose participation in those tax qualified plans at the same percentage of salary as all other employees is otherwise limited by government regulation. The SERP and EDCP participants are provided with the benefits to which they would have been entitled under the Retirement Plan or 401(k) Plan had their participation not been limited. At present, certain senior executive officers, including the Named Executive Officers, are participants in the SERP and/or EDCP. The SERP is described under the caption "Potential Payments Upon Termination or Change in Control — Retirement Benefits — Supplemental Executive Retirement Plan" on page 52 and the EDCP is described under the caption "2016 Nonqualified Deferred Compensation — Executive Deferred Compensation Plan" on page 47. We provide the SERP and the EDCP benefits because they allow our senior executive officers the opportunity to defer the same percentage of their compensation as other employees. We also believe, based on market survey data, that these plans may be necessary to make our senior executive officer retirement benefits competitive.

As of December 31, 2013, the Retirement Plan and the SERP were both closed to new employees and rehired employees. Current participants in the Retirement Plan and the SERP who continue to meet eligibility requirements will continue to earn benefits until December 31, 2023. Effective January 1, 2024, participants will no longer earn any future benefit accruals under these plans except that participants under the cash balance formula will continue to earn interest credits.

We also provide other benefits such as medical, dental, life and disability insurance, which are available to all of our employees. In addition, we provide our executive officers with additional long-term disability insurance and retiree medical and term life insurance.

Termination, Severance and Change in Control Arrangements

Our retirement and benefit plans include provisions that provide for payments to our senior executive officers, including our Named Executive Officers, in the event of a change in control of our Company. These arrangements, including the triggering events for payments and possible payment amounts, are described under the caption "Potential Payments Upon Termination or Change in Control." We believe that these arrangements are not uncommon for executives at the level of our Named Executive Officers and senior executive officer participants, including executives of the companies included in our compensation market survey information. We believe these arrangements are important factors in attracting and retaining our senior executive officers by assuring them financial and employment status protections in the event control of our Company changes. We believe such assurances of financial and employment protections help free executives from personal concerns over their futures, and thereby, can help to align their interests more closely with those of shareholders in negotiating transactions that could result in a change in control.

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Perquisites

We provide limited perquisites to senior executive officers as summarized below.

Company Aircraft

The Company leases two aircraft for the use of officers and managers in their travels to various operations throughout our service areas, as well as to meet with regulatory bodies, industry groups, financial groups, and to conduct other Company business. Our senior executive officers may use the aircraft for business purposes on a non-exclusive basis. The aircraft may also be used to transport directors to and from meetings and committee meetings of the Board of Directors. Spouses or close family members of directors and senior executive officers occasionally accompany a director or senior executive officer on the aircraft when the director or executive officer is flying for our business purposes. On rare occasions, a senior executive officer may use the aircraft for personal use that is not in connection with a business purpose. We impute income to the executive for certain expenses related to such use.

For purposes of determining total 2016 compensation, we valued the aggregate incremental cost of the personal use of our aircraft, if any, using a method that takes into account the variable expenses associated with operating the aircraft, which variable expenses are only incurred if the planes are flying. The following items are included in our aggregate incremental cost: aircraft fuel and oil expenses per hour of flight; maintenance, parts and external labor (inspections and repairs) per hour of flight; landing/parking/flight planning services expenses; crew travel expenses; supplies and food.

Medical Examinations

We offer all employees who participate in our health plans a preventive annual medical examination at no cost. Additionally, in order that we might plan for any executive-level health related retirements or resignations, we also provide each of our senior executive officers the opportunity to have a comprehensive annual medical examination from Lexington Medical Center, or the physician of his or her choice.

Security Systems

We offer installation and monitoring of home security systems for our senior executive officers. Because we operate a nuclear facility and provide essential services to the public, we believe we have a duty to help assure uninterrupted and safe operations by protecting the safety and security of our senior executive officers. We provide such installation and monitoring at more than one home for some senior executive officers.

Other Perquisites

We provide a taxable allowance to our senior executive officers for financial counseling services, including tax preparation and estate planning services. We value this benefit based on the actual charges incurred. We also pay the fees and monthly dues for club memberships for senior executive officers which are used for business purposes. We sometimes invite spouses to accompany directors and senior executive officers to our quarterly Board meetings because we believe social gatherings of directors and senior executive officers in connection with these meetings increases collegiality.

Accounting and Tax Treatment of Compensation and Effect of Financial Restatement on Executive Compensation

Deductibility of Executive Compensation

Section 162(m) of the Internal Revenue Code establishes a limit on the tax deductibility of annual compensation in excess of $1,000,000 for certain senior executive officers, including the Named Executive Officers. Certain performance-based compensation approved by shareholders is not subject to the tax deduction limit. Our Long-Term Equity Compensation Plan is currently qualified so that most performance-based awards under that Plan constitute compensation that is not subject to Section 162(m). Our Short-Term Annual Incentive Plan does not meet Section 162(m) tax deductibility requirements. To maintain flexibility in compensating senior executive officers in a manner designed to promote various corporate goals, the Compensation Committee has not adopted a policy that all compensation must be tax deductible. Because Mr. Marsh's salary exceeds the $1,000,000 threshold, we may not deduct a portion of his compensation for tax purposes. The Compensation Committee considered these tax effects in connection with its deliberations on senior executive compensation.

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Accounting for Stock Based Compensation

We account for stock based compensation in accordance with the requirements of FASB ASC Topic 718. All stock based compensation awards since 2009 have been accounted for as liability awards.

Financial Restatement

Although we have never experienced such a situation, our Board of Directors' policy would be to consider, on a case-by-case basis, a retroactive adjustment to any cash or equity-based incentive compensation paid to our senior executive officers where payment was conditioned on achievement of certain financial results that were subsequently restated or otherwise adjusted in a manner that would reduce the size of a prior award or payment.

Security Ownership Guidelines for Executive Officers

The Board has established minimum stock ownership guidelines for senior executive officers with a title of Senior Vice President and above. The Chief Executive Officer is required to hold a minimum of five times his or her annual base salary in the form of SCANA Corporation common stock and all other senior executive officers are required to hold a minimum of three times their annual base salary in the form of SCANA Corporation common stock. Any newly elected Chief Executive Officer or Senior Vice President will have a period of five years from their election to meet the required minimum ownership requirement. Once a senior executive officer complies with the minimum ownership guidelines, compliance will not be jeopardized by fluctuations in the price of the Company's common stock as long as the senior executive officer has not sold shares of the Company's common stock which were included to meet the minimum ownership requirements. The Compensation Committee of the Board monitors compliance with the policy, and also has the authority to grant a temporary waiver of the minimum share ownership requirement upon demonstration by the senior executive officer that, due to a financial hardship or other good reason, he or she cannot meet the requirement. For purposes of meeting the applicable guidelines, the following will be considered SCANA common stock: (i) shares held directly; (ii) shares held in any defined contribution, employee stock ownership plan or other stock-based plan; (iii) performance shares/units under an incentive or base salary deferral plan; (iv) performance shares/units earned and/or deferred in any long-term incentive plan account; and (v) vested and unvested restricted stock and restricted stock unit awards. The Board directed that the Company institute appropriate policies and administrative processes to ensure the minimums are effectively monitored and communicated with annual reports to the Compensation Committee. As of February 2017, all senior executive officers met the minimum stock ownership guidelines, or, for recent promotions to the senior executive officer level, are on track to meet the share ownership guidelines by their compliance date.

Non-binding Shareholder Advisory Votes on Executive Compensation and Frequency of Votes on Executive Compensation

Pursuant to the requirements of Section 14A of the Securities Exchange Act of 1934 and related Securities and Exchange Commission regulations, at our 2014 Annual Meeting of Shareholders, we submitted to our shareholders a non-binding advisory vote on approval of executive compensation. At its Committee meetings in July and October of 2014, and again at its February 2015 meeting, the Compensation Committee took into consideration that 84% of the shares voting on the non-binding advisory vote on executive compensation had voted in favor of the proposal, and the Committee concluded that no material changes to executive compensation decisions and policies were necessary in 2014. However, the Compensation Committee also considered the fact that the percentage of shares voting in favor of the non-binding advisory vote on executive compensation in 2014 was lower than the percentage of shares voting in favor of the proposal in 2011, and that certain proxy advisory firms and other interested parties had expressed some concerns regarding the designs of the Company's executive compensation plans. Accordingly, the Committee decided, with assistance from its independent compensation consultant, to consider during 2014 a number of changes to its short-term annual incentive compensation practices and long-term equity compensation practices. Ultimately, the Committee concluded that several of these changes would be appropriate and adopted them at its February 2015 meeting. These changes were implemented for the 2015 and 2016 awards under these plans, and are outlined under "Questions and Answers About Executive Compensation — Have Any Changes Been Made to Short-Term and Long-Term Incentive Compensation Practices Since the Last Shareholder Advisory Vote on Executive Compensation?" beginning on page 7.

At the 2017 Annual Meeting, shareholders will again be given the opportunity to vote on a non-binding advisory proposal relating to executive compensation. See “Proposal 2 — Advisory (Non-Binding) Vote to Approve Executive Compensation” beginning on page 60. After the 2017 Annual Meeting, taking into consideration the results of the vote at the 2017 Annual Meeting and such other factors as it deems appropriate, the Board of Directors will make a determination as to the frequency for the next six years of the advisory (non-binding) vote relating to executive compensation, and will determine when the next such vote will be held. We will file a Form 8-K with the Securities and Exchange Commission disclosing the Board’s determination.

At our 2011 Annual Meeting, we submitted to our shareholders a non-binding advisory vote on whether to hold the non-binding advisory vote on executive compensation every year, every two years, or every three years. The Committee took into consideration that, of the shares voting on the non-binding advisory vote on frequency of the vote on executive compensation, more shares voted in favor of a three year frequency than on either of the other frequency alternatives, and, accordingly, has set the current frequency of the non-binding advisory vote on executive compensation at three years. At the 2017 Annual Meeting, shareholders will again be given the opportunity to vote on a non-binding advisory proposal relating to the frequency of the vote on the non-binding vote on executive compensation. See “Proposal 3 — Advisory (Non-Binding) Vote on the Frequency of the Executive Compensation Vote” beginning on page 61. After the 2017 Annual Meeting, the next vote on the frequency of the advisory (non-binding) vote relating to executive compensation will be held at the Annual Meeting in 2023.

Compensation Committee Report

The Compensation Committee has reviewed and discussed with management the “Compensation Discussion and Analysis” included in this proxy statement. Based on that review and discussion, the Compensation Committee recommended to our Board of Directors that the “Compensation Discussion and Analysis” be included in our Annual Report on Form 10-K for the year ended December 31, 2016 for filing with the Securities and Exchange Commission, and included in this proxy statement.

Mr. James A. Bennett, Chairman
Mr. John F. A. V. Cecil
Mrs. Sharon A. Decker
Mr. James M. Micali
Mr. James W. Roquemore
Mr. Maceo K. Sloan

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SUMMARY COMPENSATION TABLE

The following table summarizes information about compensation paid or accrued during 2016, 2015 and 2014 to our Chief Executive Officer, our Chief Financial Officer and our three next most highly compensated executive officers. (As noted in the "Compensation Discussion and Analysis," we refer to these persons as our Named Executive Officers.)

Name and Principal Position (a)	Year (b)	Salary ($)(1) (c)	Bonus ($)(2) (d)	Stock Awards ($)(3) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($)(4) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(5) (h)	All Other Compensation ($)(6) (i)	Total ($) (j)
K. B. Marsh,									
Chief Executive Officer,	2016	$1,216,901	—	$2,902,015	—	$1,432,431	$395,640	$161,817	$6,108,804
President and	2015	$1,202,590	—	$2,763,823	—	$1,364,220	$251,586	$151,039	$5,733,258
Chief Operating Officer	2014	$1,107,287	$200,894	$2,835,756	—	$1,004,469	$418,123	$143,919	$5,710,448
J. E. Addison	2016	$ 631,619	—	$1,054,398	—	$ 619,574	$194,123	$ 81,160	$2,580,874
Executive Vice President and	2015	$ 624,112	—	$1,004,157	—	$ 590,070	$102,816	$ 84,264	$2,405,419
Chief Financial Officer	2014	$ 574,254	$217,055	$1,029,468	—	$ 434,109	$200,323	$ 70,733	$2,525,942
S. A. Byrne	2016	$ 631,619	—	$1,054,398	—	$ 619,574	$199,358	$ 77,192	$2,582,141
Executive Vice President	2015	$ 624,112	—	$1,004,157	—	$ 531,063	$ 85,545	$ 69,161	$2,314,038
	2014	$ 574,254	$ 75,969	$1,029,468	—	$ 379,845	$230,725	$ 75,963	$2,366,224
R. T. Lindsay	2016	$ 452,921	—	$ 560,366	—	$ 354,589	$ 87,243	$ 52,190	$1,507,309
Senior Vice President	2015	$ 456,209	—	$ 544,044	—	$ 344,261	$ 88,881	$ 55,012	$1,488,407
and General Counsel	2014	$ 425,131	$128,552	$ 566,135	—	$ 257,103	$ 81,198	$ 49,613	$1,507,732
W. K. Kissam	2016	$ 384,681	—	$ 403,139	—	$ 276,396	$112,099	$ 43,541	$1,219,856
Senior Vice President	2015	$ 383,739	—	$ 387,644	—	$ 265,767	$ 38,396	$ 45,262	$1,120,808
	2014	$ 355,230	$ 98,464	$ 400,316	—	$ 196,928	$121,884	$ 39,850	$1,212,672

(1) 2016 base salary increases for our Named Executive Officers are discussed under "— Compensation Discussion and Analysis — Base Salaries" beginning on page 29. The Named Executive Officers' salaries may appear lower for 2016 than in 2015 when considering the 2016 base salary increases due to our having one fewer pay period in 2016 than in 2015.

(2) No discretionary bonus awards were granted to any Named Executive Officers in 2016 under the Short-Term Annual Incentive Plan.

(3) Grants of performance share and restricted stock unit awards (liability awards) under the Long-Term Equity Compensation Plan, as discussed under "— Compensation Discussion and Analysis — Long-Term Equity Compensation Plan" beginning on page 33. The amounts in this column represent the aggregate grant date fair value of the awards computed in accordance with FASB ASC Topic 718. The value of performance share awards is based on the probable outcome of performance conditions, consistent with the estimate of aggregate compensation cost to be recognized over the service period determined as of the grant date under FASB ASC Topic 718, excluding the effect of estimated forfeitures. For 2016, the grant date maximum values of the performance shares, assuming the highest levels of performance, would be as follows: Mr. Marsh $3,967,588; Mr. Addison $1,441,554; Mr. Byrne $1,441,554; Mr. Lindsay $766,126; and Mr. Kissam $551,206. The assumptions made in the valuation of stock awards are set forth in Note 9 to our audited financial statements for the year ended December 31, 2016, which are included in our Form 10-K for the year ended December 31, 2016, and with this proxy statement.

(4) Payouts under the Short-Term Annual Incentive Plan were based on the levels at which we achieved growth in earnings per share targets and at which our Named Executive Officers achieved their individual and business unit financial and strategic objectives, as discussed in further detail under " — Compensation Discussion and Analysis — Short-Term Annual Incentive Plan" beginning on page 30.

(5) The aggregate change in the actuarial present value of each Named Executive Officer's accumulated benefits under SCANA's Retirement Plan and Supplemental Executive Retirement Plan from the pension plan measurement date used for financial statement reporting purposes with respect to the audited financial statements for the prior completed fiscal year to the pension plan measurement date used for financial statement reporting purposes with respect to the audited financial statements for the covered fiscal year shown, determined using interest rate and mortality rate assumptions consistent with those used in our financial statements. These plans are discussed under "— Compensation Discussion and Analysis — Retirement and Other Benefit Plans" beginning on page 38, "— Defined Benefit Retirement Plan" beginning on page 46, "— Supplemental Executive Retirement Plan" beginning on page 46, and "— Potential Payments Upon Termination or Change in Control — Retirement Benefits — Supplemental Executive Retirement Plan" beginning on page 52.

(6) Includes all other compensation paid to each Named Executive Officer, including Company contributions to the 401(k) Plan and the Executive Deferred Compensation Plan, imputed income for disability insurance and aircraft use, if any, and life insurance premiums on policies owned by Named Executive Officers. For 2016, the Company contributions to defined contribution plans were as follows: Mr. Marsh $154,464; Mr. Addison $73,092; Mr. Byrne $69,552; Mr. Lindsay $47,739; and Mr. Kissam $38,924. For 2016 perquisites did not exceed an aggregate of $10,000 for any of our Named Executive Officers.

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2016 GRANTS OF PLAN-BASED AWARDS

The following table sets forth information about each grant of an award made to a Named Executive Officer under our compensation plans during 2016.

Name (a)	Grant Date (b)	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards[1] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[2][4] Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#)[3][4] (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards ($)[5] (l)
K. B. Marsh	2-18-2016	$550,935	$1,101,870	$1,652,805							
	2-18-2016				7,634	30,534	61,068		—	—	$1,983,794
	2-18-2016							14,133			$ 918,221
J. E. Addison	2-18-2016	$238,298	$ 476,595	$ 714,893							
	2-18-2016				2,774	11,094	22,188		—	—	$ 720,777
	2-18-2016							5,135			$ 333,621
S. A. Byrne	2-18-2016	$238,298	$ 476,595	$ 714,893							
	2-18-2016				2,774	11,094	22,188		—	—	$ 720,777
	2-18-2016							5,135			$ 333,621
R. T. Lindsay	2-18-2016	$136,380	$ 272,761	$ 409,141							
	2-18-2016				1,474	5,896	11,792		—	—	$ 383,063
	2-18-2016							2,729			$ 177,303
W. K. Kissam	2-18-2016	$106,306	$ 212,612	$ 318,919							
	2-18-2016				1,061	4,242	8,484		—	—	$ 275,603
	2-18-2016							1,963			$ 127,536

(1) The amounts in columns (c), (d) and (e) represent the threshold (50% of target), target (100%) and maximum (150% of target) awards that could have been paid for 2016 under the Short-Term Annual Incentive Plan if performance criteria were met. Awards were based 50% on our achieving earnings per share objectives and 50% on our Named Executive Officers achieving business and individual performance objectives. The 2016 Short-Term Annual Incentive Plan also provided for a formulaic scaling of the total target awards up to 130% of the total target award if our net earnings per share for 2016 exceeded our goals, and for an additional 20% potential discretionary award, for a total potential payout of up to 150% of target award. For 2016, our net earnings per share goal was $4.00 and our actual net earnings per share were $4.16. Since we exceeded our net earnings per share goal and all of the Named Executive Officers met all of their individual and business unit financial and strategic objectives, awards under the 2016 Short-Term Annual Incentive Plan were earned at 130% of target by all Named Executive Officers. No additional discretionary awards were made for 2016. See "—Compensation Discussion and Analysis — Short-Term Annual Incentive Plan" beginning on page 30.

(2) Represents total potential future payouts of the 2016-2018 performance share awards under the Long-Term Equity Compensation Plan. Payout of performance share awards at the end of the 2016-2018 Plan period will be dictated by our performance against pre-determined measures of TSR and average growth in GAAP-adjusted weather-normalized net earnings per share for the three-year period. See — "Compensation Discussion and Analysis — Long-Term Equity Compensation Plan — Components of 2016-2018 Performance Share Awards," and "—Performance Criteria for the 2016-2018 Performance Share Awards" beginning on page 37.

(3) Represents restricted stock unit awards. Restricted stock unit awards are time based and vest after three years if the Named Executive Officer is still employed by us at that date, subject to exceptions for retirement, death, disability, or a change in control. See — "Compensation Discussion and Analysis — Long-Term Equity Compensation Plan — 2016-2018 Restricted Stock Unit Awards" beginning on page 37.

(4) A discussion of the components of the performance share and restricted stock unit awards is included under — "Compensation Discussion and Analysis — Long-Term Equity Compensation Plan — Components of 2016-2018 Performance Share Awards," "— Performance Criteria for the 2016-2018 Performance Share Awards," and "— 2016-2018 Restricted Stock Unit Awards" beginning on page 37.

(5) The grant date fair value of restricted stock unit awards is computed in accordance with FASB ASC Topic 718. The grant date fair value of performance share awards is based on the probable outcome of the performance conditions, consistent with the estimate of aggregate compensation cost to be recognized over the performance period determined as of the grant date under FASB ASC Topic 718, excluding the effect of estimated forfeitures.

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OUTSTANDING EQUITY AWARDS AT 2016 FISCAL YEAR-END

The following table sets forth certain information regarding equity incentive plan awards for each Named Executive Officer outstanding as of December 31, 2016.

		Stock Awards			
Name (a)	Date of Grant	Number of Shares or Units of Stock That Have Not Vested (#)(1) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($)(2) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(3)(4) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(2)(4) (j)
K. B. Marsh	2-18-16			61,068	$4,475,063
	2-18-16	14,133	$1,035,666		
	2-19-15			63,614	$4,661,634
	2-19-15	14,722	$1,078,828		
J. E. Addison	2-18-16			22,188	$1,625,937
	2-18-16	5,135	$ 376,293		
	2-19-15			23,112	$1,693,647
	2-19-15	5,349	$ 391,975		
S. A. Byrne	2-18-16			22,188	$1,625,937
	2-18-16	5,135	$ 376,293		
	2-19-15			23,112	$1,693,647
	2-19-15	5,349	$ 391,975		
R. T. Lindsay	2-18-16			11,792	$ 864,118
	2-18-16	2,729	$ 199,981		
	2-19-15			12,522	$ 917,612
	2-19-15	2,898	$ 212,365		
W. K. Kissam	2-18-16			8,484	$ 621,708
	2-18-16	1,963	$ 143,849		
	2-19-15			8,922	$ 653,804
	2-19-15	2,065	$ 151,323		

(1) The awards granted on February 18, 2016 and February 19, 2015 represent restricted stock units awarded for the 2016-2018 and 2015-2017 performance periods of the Long-Term Equity Compensation Plan that have not vested. The restricted stock units will vest December 31, 2018 and December 31, 2017, respectively, if the Named Executive Officer is still employed by us at that date, subject to exceptions for retirement, death, disability, or change in control. Additionally, each of the Named Executive Officers would also be entitled to dividend equivalents for each share that vests. For the awards granted on February 18, 2016 and February 19, 2015, respectively, assuming cumulative dividend rates as of December 31, 2016, dividend equivalents of $2.30 and $4.48, respectively, would be paid on each vested share and dividend equivalents would continue to accrue during the remaining performance period at the then current dividend rate.

(2) The market value of these awards is based on the closing market price of our common stock on the New York Stock Exchange on December 31, 2016 of $73.28.

(3) The awards granted on February 18, 2016 and February 19, 2015 represent performance shares that have not been earned. Assuming the performance criteria are met and the reported payout levels are sustained, these performance shares will vest on December 31, 2018 and December 31, 2017, respectively, subject to exceptions for retirement, death, disability, or change in control. Additionally, each of the Named Executive Officers would also be entitled to dividend equivalents for each share that vests. For the awards granted on February 18, 2016 and February 19, 2015, respectively, assuming cumulative dividend rates as of December 31, 2016, dividend equivalents of $2.30 and $4.48, respectively, would be paid on each vested share and dividend equivalents would continue to accrue during the remaining performance period at the then current dividend rate.

(4) For the 2016-2018 awards, performance shares tracking against TSR (50% of performance share award) are reflected above at a maximum payout since our TSR for the most recently completed fiscal year was above target. Therefore, the number of shares and payout value shown in columns (i) and (j) are based on the maximum performance measure for the TSR portions of the performance shares. Performance shares tracking against average growth in GAAP-adjusted weather-normalized net earnings per share (50% of performance share award) for the 2016-2018 awards are also reflected at a maximum payout since our GAAP-adjusted weather-normalized net earnings per share for the most recently completed fiscal year were also above target. Therefore, the number of shares and payout value shown in columns (i) and (j) are based on the maximum performance measure for the growth in GAAP-adjusted weather-normalized net earnings per share portion of the performance shares.

For the 2015-2017 awards, performance shares tracking against TSR (50% of performance share award) are reflected above at a maximum payout since our average TSR for the most recently completed fiscal year was above target. Therefore, the number of shares and payout value shown in columns (i) and (j) are based on the maximum performance measure for the TSR portions of the performance shares. Performance shares tracking against average growth in GAAP-adjusted weather-normalized net earnings per share (50% of performance share award) for the 2015-2017 awards are reflected at a maximum payout since our average GAAP-adjusted weather-normalized net earnings per share for the most recently completed fiscal year was above target. Therefore, the number of shares and payout value shown in columns (i) and (j) are based on the maximum performance measure for the growth in GAAP-adjusted weather-normalized net earnings per share portion of the performance shares.

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2016 OPTION EXERCISES AND STOCK VESTED

The following table sets forth information about stock awards that vested for each Named Executive Officer during 2016. None of our employees, including the Named Executive Officers, currently hold stock options.

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#)(1) (d)	Value Realized on Vesting ($)(1) (e)
K. B. Marsh	—	0	61,132	$4,479,753
	—	0	11,530	$ 850,453
J. E. Addison	—	0	22,191	$1,626,156
	—	0	4,186	$ 308,759
S. A. Byrne	—	0	22,191	$1,626,156
	—	0	4,186	$ 308,759
R. T. Lindsay	—	0	12,205	$ 894,382
	—	0	2,302	$ 169,796
W. K. Kissam	—	0	8,628	$ 632,260
	—	0	1,628	$ 120,081

(1)Represents the 2014-2016 performance share awards and restricted stock unit awards that vested at the end of the three-year vesting period. For a discussion of these awards, see “Long-Term Equity Compensation Plan — Performance Criteria for the 2014-2016 Performance Share Awards and Earned and Vested Awards for the 2014-2016 Performance Period” and “— 2014-2016 Restricted Stock Unit Awards.” Dollar amounts in column (e) are calculated by multiplying the number of performance shares shown in column (d) by the closing price of SCANA common stock on the vesting date (December 31, 2016) and by multiplying the number of shares of restricted stock units shown in column (d) by the opening price of SCANA common stock on the vesting date. In addition to the amounts above, on the vesting date, each Named Executive Officer also received dividend equivalents of $6.58 per share on the shares listed above.

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PENSION BENEFITS

The following table sets forth certain information relating to our Retirement Plan and Supplemental Executive Retirement Plan.

Name (a)	Plan Name (b)	Number of Years Credited Service (#)(1) (c)	Present Value of Accumulated Benefit ($)(1)(2) (d)	Payments During Last Fiscal Year ($) (e)
K. B. Marsh	SCANA Retirement Plan	32	$ 943,036	$0
	SCANA Supplemental Executive Retirement Plan	32	$2,048,107	$0
J. E. Addison	SCANA Retirement Plan	25	$ 454,646	$0
	SCANA Supplemental Executive Retirement Plan	25	$ 737,767	$0
S. A. Byrne	SCANA Retirement Plan	21	$ 421,633	$0
	SCANA Supplemental Executive Retirement Plan	21	$ 977,386	$0
R. T. Lindsay	SCANA Retirement Plan	7	$ 182,025	$0
	SCANA Supplemental Executive Retirement Plan	7	$ 307,519	$0
W. K. Kissam	SCANA Retirement Plan	28	$ 422,542	$0
	SCANA Supplemental Executive Retirement Plan	28	$ 205,948	$0

(1) Computed as of December 31, 2016, the plan measurement date used for financial statement reporting purposes with respect to the audited financial statements for the last completed fiscal year. Other than as set forth in disclosures related to our Change of Control Plans, we do not provide extra years of credited service under these plans. See "Potential Payments Upon Termination or Change in Control" beginning on page 49.

(2) Present value calculation determined using current account balances for each Named Executive Officer as of December 31, 2016, based on assumed retirement at normal retirement age (specified as age 65) and other assumptions as to valuation method, interest rate, discount rate and other material factors as set forth in Note 8 to our audited financial statements for the year ended December 31, 2016, which are included in our Form 10-K for the year ended December 31, 2016, and with this Proxy Statement.

The SCANA Retirement Plan (the "Retirement Plan") is a tax qualified defined benefit plan and the Supplemental Executive Retirement Plan (the "SERP") is a nonqualified deferred compensation plan. The plans provide for full vesting after three years of service or after reaching age 65. All Named Executive Officers are fully vested in both plans. As of December 31, 2013, the Retirement Plan and the SERP were both closed to new employees and rehired employees. Current participants in the Retirement Plan and the SERP who continue to meet eligibility requirements will continue to earn benefits until December 31, 2023. Effective January 1, 2024, participants will no longer earn any future benefit accruals under these plans except that participants under the cash balance formula of the Retirement Plan will continue to earn interest credits.

Defined Benefit Retirement Plan

The Retirement Plan uses a mandatory cash balance benefit formula for employees hired on or after January 1, 2000. Effective July 1, 2000, SCANA employees hired prior to January 1, 2000 were given the choice of remaining under the Retirement Plan's final average pay formula or switching to the cash balance formula. All the Named Executive Officers participate under the cash balance formula of the Retirement Plan.

The cash balance formula is expressed in the form of a hypothetical account balance. Account balances are increased monthly by interest and compensation credits. The interest rate used for accumulating account balances is determined annually based on 30-year treasury securities and the applicable segment rates determined under Internal Revenue Code Section 417(c)(3)(D) calculated using the rates for December of the previous calendar year. Compensation credits equal 5% of compensation up to the Social Security wage base and 10% of compensation in excess of the Social Security wage base.

Supplemental Executive Retirement Plan

In addition to the Retirement Plan, we provide the SERP for certain eligible employees hired before December 31, 2013, including the Named Executive Officers. The SERP is an unfunded plan that provides for benefit payments in addition to benefits payable under the qualified Retirement Plan in order to replace benefits lost under the Retirement Plan because of Internal Revenue Code maximum benefit limitations on tax qualified plans. The SERP is discussed under the caption "— Potential Payments Upon Termination or Change in Control — Retirement Benefits" beginning on page 52, and under the caption "— Compensation Discussion and Analysis — Retirement and Other Benefit Plans" beginning on page 38.

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2016 NONQUALIFIED DEFERRED COMPENSATION

The following table sets forth information with respect to the Executive Deferred Compensation Plan:

Name (a)	Executive Contributions in Last FY ($)(1) (b)	Registrant Contributions in Last FY ($)(1) (c)	Aggregate Earnings in Last FY ($)(1) (d)	Aggregate Withdrawals Distributions ($) (e)	Aggregate Balance at Last FYE ($)(1) (f)
K. B. Marsh	$138,833	$138,564	$449,612	—	$3,485,649
J. E. Addison	$238,881	$ 57,192	$135,834	—	$1,590,666
S. A. Byrne	$ 53,791	$ 53,652	$443,140	—	$2,397,879
R. T. Lindsay	$730,921	$ 31,839	$187,821	—	$3,435,101
W. K. Kissam	$ 23,093	$ 23,024	$ 7,057	—	$ 352,036

(1) The amounts reported in columns (b) and (c) are reflected in columns (c) and (i), respectively, of the Summary Compensation Table. No amounts in column (d) are reported, or have been previously reported, in the Summary Compensation Table as there were no above market or preferential earnings credited to any Named Executive Officer's account. The portions of the amounts reported in column (f), that represent Named Executive Officer and Company contributions, were previously reported in columns (c) and (i), respectively, of the 2015 and 2014 Summary Compensation Tables in the following amounts: Mr. Marsh $251,542 for 2015, $244,925 for 2014; Mr. Addison $305,848 for 2015, $95,465 for 2014; Mr. Byrne $94,876 for 2015, $107,041 for 2014; Mr. Lindsay $826,584 for 2015, $483,218 for 2014; and Mr. Kissam $47,917 for 2015 (Mr. Kissam was not a Named Executive Officer in 2014). For prior years, amounts would have been included in the Summary Compensation Table when required by the rules of the Securities and Exchange Commission.

Executive Deferred Compensation Plan

The Executive Deferred Compensation Plan (the "EDCP") is a nonqualified deferred compensation plan in which our senior executive officers, including Named Executive Officers, and our Directors, may participate if they choose to do so. Each employee participant may elect to defer up to 25% of that part of his or her eligible earnings (as defined in the SCANA Corporation 401(k) Retirement Savings Plan, our 401(k) plan), that exceeds the limitation on compensation otherwise required under Internal Revenue Code Section 401(a)(17), without regard to any deferrals or the foregoing of compensation. For 2016, employee participants could defer eligible earnings in excess of $265,000. In addition, an employee participant may elect to defer up to 100% of any performance share award for the year under our Long-Term Equity Compensation Plan. We match the amount of compensation deferred by each employee participant up to 6% of the employee participant's eligible earnings (excluding performance share awards) in excess of the Internal Revenue Code Section 401(a)(17) limit.

In 2014, we amended and restated the EDCP to allow non-employee directors to participate after they have accumulated sufficient shares of our stock to satisfy our minimum share ownership guidelines. A director may defer all or a portion of his or her cash retainer fee amounts for a year under the Director Compensation and Deferral Plan (which is discussed beginning on page 56) or under the EDCP. A director who has not elected to defer all or a portion of his or her stock retainer fee amounts under the Director Compensation and Deferral Plan for a year may also elect to defer under the EDCP 100% (but not less than 100%) of his or her stock retainer fee amounts for a year.

We record the amount of each participant's deferred compensation and the amount we match in a ledger account and credit a rate of return to each participant's ledger account based on hypothetical investment alternatives chosen by the participant. The internal committee that administers the EDCP designates various hypothetical investment alternatives from which the participants may choose. Using the results of the hypothetical investment alternatives chosen, we credit each participant's ledger account with the amount it would have earned if the account amount had been invested in that alternative. If the chosen hypothetical investment alternative loses money, the participant's ledger account is reduced by the corresponding amount. All amounts credited to a participant's ledger accounts continue to be credited or reduced pursuant to the chosen investment alternatives until such amounts are paid in full to the participant or his or her beneficiary. No actual investments are made. The investment alternatives are only used to generate a rate of increase (or decrease) in the ledger accounts, and amounts paid to participants are solely our obligation. All payouts under the EDCP are made in cash. In connection with this Plan, the Board has established a grantor trust (known as the "SCANA Corporation Executive Benefit Plan Trust") for the purpose of accumulating funds to satisfy the obligations we incur under the EDCP. At any time prior to a change in control we may transfer assets to the trust to satisfy all or part of our obligations under the EDCP. Notwithstanding the establishment of the trust, the right of participants to receive future payments is an unsecured claim against us. The trust has been partially funded with respect to ongoing deferrals and Company matching funds since October 2001.

In 2016, the Named Executive Officers' ledger accounts were credited with earnings or losses based on the following hypothetical investment alternatives and rates of returns:

> Wells Fargo Stable Return Fund (1.53%); Vanguard Total Bond Market Index Fund (2.60%); PIMCO Total Return Fund (2.59%); Dodge & Cox Stock Fund (21.28%); Vanguard Institutional Index Fund (11.93%); T Rowe Price Mid Cap Value Fund (24.32%); Vanguard Extended Market Index Fund (16.13%); AMG TimesSquare Mid Cap Growth Fund (7.53%); Victory RS Partners Fund (24.41%); Voya Smallcap Opportunities Fund (12.72%); Janus Research Fund (1.56%); Dodge & Cox International Stock Fund (8.26%); Vanguard Total International Stock Index Fund (4.67%); SCANA Corporation Stock (25.16%); Vanguard Institutional Target Retirement Income Fund (5.29%); Vanguard Institutional Target Retirement 2015 (6.27%); Vanguard Institutional Target Retirement 2020 (7.04%); Vanguard Institutional Target Retirement 2025 (7.56%); Vanguard Institutional Target Retirement 2030 (7.97%); Vanguard Institutional Target Retirement 2035 (8.39%); Vanguard Institutional Target Retirement 2040 (8.81%); Vanguard Institutional Target Retirement 2045 (8.94%); Vanguard Institutional Target Retirement 2050 (8.95%); Vanguard Institutional Target Retirement 2055 (9.00%); Vanguard Institutional Target Retirement 2060 (8.94%).

The measures for calculating interest or other plan earnings are based on the investments chosen by the manager of each investment vehicle, except the SCANA Corporation stock, the earnings of which are based on the value of our common stock.

The hypothetical investment alternatives may be changed at any time on a prospective basis by the participants in accordance with the telephone, electronic, and written procedures and forms adopted by the committee for use by all participants on a consistent basis.

Participants may elect the deferral period for each separate deferral made under the Plan. Employee participants may elect to defer payment of eligible earnings or performance share awards until their separation from service or until a date certain. Any post-2004 deferrals and hypothetical earnings thereon must be payable at the same date certain if the date certain payment alternative is chosen. Notwithstanding a participant's election of a date certain deferral period or any modification thereof as discussed above, deferred amounts will be paid, or begin to be paid as soon as practicable after the earliest to occur of participant's death, separation from service, or, with respect to pre-2005 deferrals and hypothetical earnings thereon, disability. "Separation from service" is defined by the EDCP (i) with respect to an employee, as any termination of the participant's employment relationship with us and any of our affiliates, and, with respect to post-2004 deferrals and hypothetical earnings thereon, the participant's separation from service from us and our affiliates as determined under Internal Revenue Code Section 409A and the guidelines issued thereunder, and (ii) with respect to a non-employee director, any separation from service with us and our affiliates in a manner consistent with Code Section 409A and the guidelines issued thereunder. Directors may elect to defer cash and stock retainer fees only until separation from service as a director.

Participants also elect the manner in which their deferrals and hypothetical earnings thereon will be paid. For amounts earned and vested after January 1, 2005, distribution and withdrawal elections are subject to Internal Revenue Code Section 409A. All amounts payable at a date certain prior to an employee participant's separation from service, death, or, with respect to pre-2005 deferrals and hypothetical earnings thereon, disability, must be paid in the form of a single cash payment. Payments made after separation from service, death, or, with respect to pre-2005 deferrals and hypothetical earnings thereon, disability, will also be paid in the form of a single cash payment. Instead of a single cash payment, a participant may, however, elect to have all amounts payable as a result of separation from service after attainment of age 55, death while employed or serving as a director and after attainment of age 55, or, with respect to pre-2005 deferrals and hypothetical earnings thereon, separation from service due to disability, paid in the form of annual installments over a period not to exceed five years with respect to post-2004 deferrals and hypothetical earnings thereon or 15 years with respect to pre-2005 deferrals and hypothetical earnings thereon.

In accordance with procedures established by the Compensation Committee, with respect to any deferrals to a date certain, an employee participant may request that the Compensation Committee approve an additional deferral period of at least 60 months as to any post-2004 deferrals and hypothetical earnings thereon, or at least 12 months as to any pre-2005 deferrals and hypothetical earnings thereon. The request must be made at least 12 months before the expiration of the date certain deferral period for which an additional deferral period is being sought.

Payments as a result of a separation from service of post-2004 deferrals and hypothetical earnings thereon to persons who are "specified employees" under our procedures adopted in accordance with Internal Revenue Code Section 409A and guidance thereunder (certain officers and executive officers) must be deferred until the earlier of (i) the first day of the seventh month following the participant's separation from service or (ii) the date of the participant's death.

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A participant may request and receive, with the approval of the Compensation Committee, an acceleration of the payment of some or all of the participant's ledger account due to severe financial hardship as the result of certain extraordinary and unforeseeable circumstances arising as a result of events beyond the individual's control. With respect to pre-2005 deferrals and hypothetical earnings thereon, a participant may also obtain a single lump sum payment of any or all of his or her ledger account on an accelerated basis by forfeiting 10% of the amount accelerated, or by making the election, not less than 12 months prior to the date on which the accelerated payment is to be made, to accelerate the payment to a date not earlier than 12 months after the election request is received by the Committee. Additionally, the Plan provides for the acceleration of payments following a change in control of our Company. The change in control provisions are discussed under "— Potential Payments Upon Termination or Change in Control — Change in Control Arrangements."

Potential Payments Upon Termination or Change in Control

Change in Control Arrangements

Effective December 31, 2009, we terminated the SCANA Corporation Key Executive Severance Benefits Plan, which provided for payment of benefits immediately upon a change in control unless the Plan was terminated prior to the change in control. Also as of December 31, 2009, we amended our change in control benefits to eliminate excise tax gross ups.

Triggering Events for Payments under the Supplementary Key Executive Severance Benefits Plan

The SCANA Corporation Supplementary Key Executive Severance Benefits Plan (the "Supplementary Severance Plan") provides for payments to our senior executive officers in connection with a change in control of our Company. The Supplementary Severance Plan provides for payment of benefits if, within 24 months after a change in control, we terminate a senior executive officer's employment without just cause or if the senior executive officer terminates his or her employment for good reason.

Our Supplementary Severance Plan is intended to advance the interests of our Company by providing highly qualified executives and other key personnel with an assurance of equitable treatment in terms of compensation and economic security and to induce continued employment with the Company in the event of certain changes in control. We believe that an assurance of equitable treatment will enable valued executives and key personnel to maintain productivity and focus during a period of significant uncertainty inherent in change in control situations. We also believe that compensation plans of this type aid the Company in attracting and retaining the highly qualified professionals who are essential to our success. The structure of the Plan, and the benefits which might be paid in the event of a change in control, are reviewed as part of the Compensation Committee's annual review of tally sheets for each senior executive officer.

The Supplementary Severance Plan provides that a "change in control" will be deemed to occur under the following circumstances:

- if any person or entity becomes the beneficial owner, directly or indirectly, of 25% or more of the combined voting power of the outstanding shares of our common stock;

- if, during a consecutive two-year period, a majority of our directors cease to be individuals who either (i) were directors on the Board at the beginning of such period, or (ii) became directors after the beginning of such period but whose election by the Board, or nomination for election by our shareholders, was approved by at least two-thirds of the directors then still in office who either were directors at the beginning of such period, or whose election or nomination for election was previously so approved;

- if (i) we consummate a merger or consolidation of our Company with another corporation (except a merger or consolidation in which our outstanding voting shares prior to such transaction continue to represent at least 80% of the combined voting power of the surviving entity's outstanding voting shares after such transaction), or (ii) our shareholders approve a plan of complete liquidation of our Company, or an agreement to sell or dispose of all or substantially all of our assets; or

- if we consummate the sale of the stock of, or our shareholders approve a plan of complete liquidation of, or an agreement for the sale or disposition of substantially all of the assets of any of our subsidiaries that the Board designates to be a material subsidiary. This last provision would constitute a change in control only with respect to participants exclusively assigned to the affected subsidiary.

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As noted above, benefits under the Supplementary Severance Plan would be triggered if, within 24 months after a change in control, we terminated the senior executive officer's employment without just cause or if the senior executive officer terminated his or her employment for good reason. Under the Plan, we would be deemed to have "just cause" for terminating the employment of a senior executive officer if he or she:

- willfully and continually failed to substantially perform his or her duties after we made demand for substantial performance;
- willfully engaged in conduct that is demonstrably and materially injurious to us; or
- were convicted of a felony or certain misdemeanors.

A senior executive officer would be deemed to have "good reason" for terminating his or her employment if, after a change in control, without his or her consent, any one or more of the following occurred:

- a material diminution in his or her base salary;
- a material diminution in his or her authority, duties, or responsibilities;
- a material diminution in the authority, duties, or responsibilities of the supervisor to whom he or she is required to report, including a requirement that he or she report to one of our officers or employees instead of reporting directly to the Board;
- a material diminution in the budget over which he or she retains authority;
- a material change in the geographic location at which he or she must perform services; or
- any other action or inaction that constitutes a material breach by us of the agreement under which he or she provides services.

Potential Benefits Payable under the Supplementary Severance Plan

The benefits we would be required to pay our senior executive officers under the Supplementary Severance Plan immediately upon the occurrence of a triggering event subsequent to a change in control are as follows:

- an amount intended to approximate 2.5 times the sum of: (i) his or her annual base salary (before reduction for certain pre-tax deferrals) in effect as of the change in control, plus (ii) his or her full targeted annual incentive opportunity in effect as of the change in control;
- an amount equal to the participant's full targeted annual incentive opportunity in effect under each existing annual incentive plan or program for the year in which the change in control occurs;
- if the participant's benefit under the SERP is determined using the final average pay formula under the Retirement Plan, an amount equal to the present lump sum value of the actuarial equivalent of his or her accrued benefit under the Retirement Plan and the SERP through the date of the change in control, calculated as though he or she had attained age 65 and completed 35 years of benefit service as of the date of the change in control, and as if his or her final average earnings under the Retirement Plan equaled the amount determined after applying cost-of-living increases to his or her annual base salary from the date of the change in control until the date he or she would reach age 65, and without regard to any early retirement or other actuarial reductions otherwise provided in any such plan (this benefit will be offset by the actuarial equivalent of the participant's benefit provided by the Retirement Plan and the Participant's benefit under the SERP);
- if the participant's benefit under the SERP is determined using the cash balance formula under the Retirement Plan, an amount equal to the present value as of the date of the change in control of his or her accrued benefit, if any, under our SERP, determined prior to any offset for amounts payable under the Retirement Plan, increased by the present value of the additional projected pay credits and periodic interest credits that would otherwise accrue under the Plan (based on the Plan's actuarial assumptions) assuming that he or she remained employed until reaching age 65, and reduced by his or her cash balance account under the Retirement Plan, and further reduced by an amount equal to his or her benefit under the SERP;

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- an amount equal to the value of all amounts credited to each participant's EDCP ledger account as of the date of the change in control, plus interest on the benefits payable under the EDCP at a rate equal to the sum of the prime interest rate as published in the Wall Street Journal on the most recent publication date prior to the date of the change in control plus 3%, calculated through the end of the month preceding the month in which the benefits are distributed, reduced by the value of his or her benefit under the EDCP as of the date of the change in control; and

- an amount equal to the projected cost for medical, long-term disability and certain life insurance coverage for three years following the change in control as though he or she had continued to be our employee.

In addition to the benefits above (unless their agreements with us provide otherwise), our senior executive officers would also be entitled to benefits under our other plans in which they participate as follows:

- a benefit distribution under the Long-Term Equity Compensation Plan equal to 100% of the target awards for all performance periods not completed as of the date of the change in control, if any; and

- any amounts previously earned, but not yet paid, under the terms of any of our other plans or programs.

Calculation of Benefits Potentially Payable to our Named Executive Officers under the Supplementary Severance Plan if a Triggering Event had Occurred as of December 30, 2016

The Supplementary Severance Plan provides that, if (i) we had been subject to a change in control in the past 24 months, and (ii) as of December 30, 2016, either we had terminated the employment of any of our Named Executive Officers without just cause or they had terminated their employment for good reason, such terminated Named Executive Officer would have been immediately entitled to all of the benefits outlined below, together with interest, calculated as outlined above under " — Potential Benefits Payable under the Supplementary Severance Plan," on his or her EDCP account balance. The actual amount of any such additional interest payment would depend upon the date the change in control occurred.

Mr. Marsh would have been entitled to the following: an amount equal to 2.5 times his 2016 base salary and target short-term incentive award — $5,815,425; an amount equal to the excess payable under the SERP as calculated under the assumptions described above — $802,454; an amount equal to insurance continuation benefits for three years — $75,882; an amount equal to the difference between target and actual annual incentive award under the Short-Term Annual Incentive Plan — $0 (for 2016, the Short-Term Annual Incentive Plan paid out above target, resulting in no additional benefit); an amount equal to the value of 100% of his target performance shares under the Long-Term Equity Compensation Plan for all performance periods not completed — $4,568,348; and an amount equal to the value of 100% of his restricted stock units under the Long-Term Equity Compensation Plan — $2,959,413. The total value of these change in control benefits would have been $14,221,522. In addition, Mr. Marsh would have been paid amounts previously earned, but not yet paid, as follows: 2016 actual short-term annual incentive award — $1,432,431; 2016 actual long-term equity award — $5,808,322; EDCP account balance — $3,485,649; SERP and Retirement Plan account balances — $3,014,940; vacation accrual — $37,965; as well as his 401(k) Plan account balance.

Mr. Addison would have been entitled to the following: an amount equal to 2.5 times his 2016 base salary and target short-term incentive award — $2,780,138; an amount equal to the excess payable under the SERP as calculated under the assumptions described above — $656,377; an amount equal to insurance continuation benefits for three years — $86,202; an amount equal to the difference between target and actual annual incentive award under the Short-Term Annual Incentive Plan — $0 (for 2016, the Short-Term Annual Incentive Plan paid out above target, resulting in no additional benefit); an amount equal to the value of 100% of his target performance shares under the Long-Term Equity Compensation Plan for all performance periods not completed — $1,659,792; and an amount equal to the value of 100% of his restricted stock units under the Long-Term Equity Compensation Plan — $1,075,018. The total value of these change in control benefits would have been $6,257,526. In addition, Mr. Addison would have been paid amounts previously earned, but not yet paid, as follows: 2016 actual short-term annual incentive award — $619,574; 2016 actual long-term equity award — $2,108,476; EDCP account balance — $1,590,666; SERP and Retirement Plan account balances — $1,214,880; vacation accrual — $7,943; as well as his 401(k) Plan account balance.

Mr. Byrne would have been entitled to the following: an amount equal to 2.5 times his 2016 base salary and target short-term incentive award — $2,780,138; an amount equal to the excess payable under the SERP as calculated under the assumptions described above — $662,217; an amount equal to insurance continuation benefits for three years — $63,552; an amount equal to the difference between target and actual annual incentive award under the Short-Term

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Annual Incentive Plan — $0 (for 2016, the Short-Term Annual Incentive Plan paid out above target, resulting in no additional benefit); an amount equal to the value of 100% of his target performance shares under the Long-Term Equity Compensation Plan for all performance periods not completed — $1,659,792; and an amount equal to the value of 100% of his restricted stock units under the Long-Term Equity Compensation Plan — $1,075,018. The total value of these change in control benefits would have been $6,240,716. In addition, Mr. Byrne would have been paid amounts previously earned, but not yet paid, as follows: 2016 actual short-term annual incentive award — $619,574; 2016 actual long-term equity award — $2,108,476; EDCP account balance — $2,397,879; SERP and Retirement Plan account balances — $1,422,870; vacation accrual — $2,444; as well as his 401(k) Plan account balance.

Mr. Lindsay would have been entitled to the following: an amount equal to 2.5 times his 2016 base salary and target short-term incentive award — $1,818,405; an amount equal to the excess payable under the SERP as calculated under the assumptions described above — $0 (Mr. Lindsay is 66 and is not entitled to an excess SERP benefit); an amount equal to insurance continuation benefits for three years — $54,303; an amount equal to the difference between target and actual annual incentive award under the Short-Term Annual Incentive Plan — $0 (for 2016, the Short-Term Annual Incentive Plan paid out above target, resulting in no additional benefit); an amount equal to the value of 100% of his target performance shares under the Long-Term Equity Compensation Plan for all performance periods not completed — $890,865; and an amount equal to the value of 100% of his restricted stock units under the Long-Term Equity Compensation Plan — $581,037. The total value of these change in control benefits would have been $3,344,610. In addition, Mr. Lindsay would have been paid amounts previously earned, but not yet paid, as follows: 2016 actual short-term annual incentive award — $354,589; 2016 actual long-term equity award — $1,159,634; EDCP account balance — $3,435,101; SERP and Retirement Plan account balances — $489,544; vacation accrual — $109; as well as his 401(k) Plan account balance.

Mr. Kissam would have been entitled to the following: an amount equal to 2.5 times his 2016 base salary and target short-term incentive award — $1,497,950; an amount equal to the excess payable under the SERP as calculated under the assumptions described above — $316,788; an amount equal to insurance continuation benefits for three years — $80,964; an amount equal to the difference between target and actual annual incentive award under the Short-Term Annual Incentive Plan — $0 (for 2016, the Short-Term Annual Incentive Plan paid out above target, resulting in no additional benefit); an amount equal to the value of 100% of his target performance shares under the Long-Term Equity Compensation Plan for all performance periods not completed — $637,756; and an amount equal to the value of 100% of his restricted stock units under the Long-Term Equity Compensation Plan — $414,472. The total value of these change in control benefits would have been $2,947,930. In addition, Mr. Kissam would have been paid amounts previously earned, but not yet paid, as follows: 2016 actual short-term annual incentive award — $276,396; 2016 actual long-term equity award — $819,825; EDCP account balance — $352,036; SERP and Retirement Plan account balances — $647,702; vacation accrual — $20,815; as well as his 401(k) Plan account balance.

Retirement Benefits

Supplemental Executive Retirement Plan

The Supplemental Executive Retirement Plan (the "SERP") is an unfunded nonqualified defined benefit plan. The SERP was established for the purpose of providing supplemental retirement income to certain of our employees, including the Named Executive Officers, whose benefits under the Retirement Plan are limited in accordance with the limitations imposed by the Internal Revenue Code on the amount of annual retirement benefits payable to employees from qualified pension plans or on the amount of annual compensation that may be taken into account for all qualified plan purposes, or by certain other design limitations on determining compensation under the Retirement Plan. Subject to the terms of the SERP, a participant becomes eligible to receive benefits under the SERP upon termination of his or her employment with us (or at such later date as may be provided in a participant's agreement with us), if the participant has become vested in his or her accrued benefit under the Retirement Plan prior to termination of employment. However, if a participant is involuntarily terminated following or incident to a change in control and prior to becoming fully vested in his or her accrued benefit under the Retirement Plan, the participant will automatically become fully vested in his or her benefit under the SERP and a benefit will be payable under the SERP. The term "change in control" has the same meaning in the SERP as in the Supplementary Severance Plan. See the discussion under "— Change in Control Arrangements."
The amount of any benefit payable to a participant under the SERP will depend upon whether the participant's benefit under the SERP is determined using the final average pay formula under the Retirement Plan or the cash balance pay formula under the Retirement Plan. All of our Named Executive Officers participate under the cash balance pay formula of the Retirement Plan. Unless otherwise provided in a participant agreement, the amount of any SERP benefit payable pursuant to the SERP to a participant whose benefit is determined using the final average pay formula under the

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Retirement Plan will be determined at the time the participant first becomes eligible to receive benefits under the SERP and will be equal to the excess, if any, of:

- the monthly pension amount that would have been payable at normal retirement age or, if applicable, delayed retirement age under the Retirement Plan (as such terms are defined under the Retirement Plan), to the participant determined based on his or her compensation and disregarding the Internal Revenue Code limitations and any reductions due to the participant's deferral of compensation under any of our nonqualified deferred compensation plans (other than the SERP), over

- the monthly pension amount payable to the participant at normal retirement age or, if applicable, delayed retirement age under the Retirement Plan.

The calculation of this benefit assumes that payment is made to the participant at normal retirement age or, if applicable, delayed retirement age under the Retirement Plan, and is calculated using the participant's years of benefit service and final average earnings as of the date of the participant's termination of employment.

Unless otherwise provided in a participant agreement, the amount of any benefit payable pursuant to the SERP as of any determination date to a participant whose SERP benefit is determined using the cash balance formula under the Retirement Plan will be equal to:

- the benefit that otherwise would have been payable under the Retirement Plan as of the determination date, based on his or her compensation and disregarding the Internal Revenue Code limitations, minus

- the Participant's benefit determined under the Retirement Plan as of the determination date.

For purposes of the SERP, "compensation" is defined as determined under the Retirement Plan, without regard to the limitation under Section 401(a)(17) of the Internal Revenue Code, including any amounts of compensation otherwise deferred under any non-qualified deferred compensation plan (excluding the SERP).

The benefit payable to a participant under the SERP will be paid, or commence to be paid, as of the first day of the calendar month following the date the participant first becomes eligible to receive a benefit under the SERP (the "payment date"). The form of payment upon distribution of benefits under the SERP will depend upon whether the benefit constitutes a "grandfathered benefit" or a "non-grandfathered benefit." For purposes of the SERP, "grandfathered benefit" means the vested portion of the benefit payable under the SERP assuming the participant's determination date is December 31, 2004, increased with interest credits (for a participant whose benefit under the SERP is determined using the cash balance formula under the Retirement Plan) and earnings (for a participant whose benefit under the SERP is determined using the final average pay formula under the Retirement Plan) at the rates determined under the Retirement Plan through any later determination date. A participant's grandfathered benefit is governed by the terms of the SERP in effect as of October 3, 2004 and will be determined in a manner consistent with Internal Revenue Code Section 409A and the guidance thereunder. "Non-grandfathered benefit" means the portion of the benefit payable under the SERP that exceeds the grandfathered benefit.

With respect to grandfathered benefits, the participant may elect, in accordance with procedures we establish, to receive a distribution of such grandfathered benefit in either of the following two forms of payment:

- a single sum distribution of the value of the participant's grandfathered benefit under the SERP determined as of the last day of the month preceding the payment date; or

- a lifetime annuity benefit with an additional death benefit payment as follows: a lifetime annuity that is the actuarial equivalent of the participant's single sum amount which provides for a monthly benefit payable for the participant's life, beginning on the payment date. In addition to this life annuity, commencing on the first day of the month following the participant's death, his or her designated beneficiary will receive a benefit of 60% of the amount of the participant's monthly payment continuing for a 15 year period. If, however, the beneficiary dies before the end of the 15 year period, the lump sum value of the remaining monthly payments of the survivor benefit will be paid to the beneficiary's estate. The participant's life annuity will not be reduced to reflect the "cost" of providing the 60% survivor benefit feature. "Actuarial equivalent" is defined by the SERP as equality in value of the benefit provided under the SERP based on actuarial assumptions, methods, factors and tables that would apply under the Retirement Plan under similar circumstances.

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With respect to non-grandfathered benefits, a participant whose benefit under the SERP is determined using the final average pay formula under the Retirement Plan will receive a distribution of his or her benefit under the SERP as a single sum distribution equal to the actuarial equivalent present value (at the date of the participant's termination of employment) of the participant's SERP benefit determined as of normal retirement age, reflecting any terms under the Retirement Plan applicable to early retirement benefits if the participant is eligible for such early retirement benefits.

Except as otherwise provided below, a participant whose benefit under the SERP is determined using the cash balance formula under the Retirement Plan had the opportunity to elect on or before January 1, 2009 to receive a distribution of his non-grandfathered benefit in one of the following forms of payment:

- a single sum distribution of the value of the participant's non-grandfathered benefit determined as of the last day of the month preceding the payment date;
- an annuity for the participant's lifetime that is the actuarial equivalent of the participant's single sum amount, and that commences on the payment date; or
- an annuity that is the actuarial equivalent of the participant's single sum amount, that commences on the payment date, and that provides payments for the life of the participant and, upon his or her death, continues to pay an amount equal to 50%, 75% or 100% (as elected by the participant prior to benefit commencement) of the annuity payment to the contingent annuitant designated by the participant at the time the election is made.

A participant whose benefit under the SERP is determined using the cash balance formula under the Retirement Plan who first became an eligible employee after 2008, and who was not eligible to participate in the EDCP before becoming eligible to participate in the SERP, may elect at any time during the first 30 days following the date he becomes an eligible employee to receive a distribution of his or her non-grandfathered benefit in one of the forms specified above.

Participants whose benefits under the SERP are determined using the cash balance formula under the Retirement Plan will receive distributions under the SERP as follows:

- If a participant has terminated employment before attaining age 55, the participant's non-grandfathered benefit will be paid in the form of a single sum distribution of the value of the participant's non-grandfathered benefit determined as of the last day of the month preceding the payment date.
- If a participant has terminated employment after attaining age 55, and the value of the participant's non-grandfathered benefit does not exceed $100,000 at the time of such termination of employment, such benefit shall be paid in the form of a single sum distribution of the value of the participant's non-grandfathered benefit determined as of the last day of the month preceding the payment date.
- In the absence of an effective election, and assuming that the provisions in the two bullet points immediately above do not apply, non-grandfathered SERP benefits owed to the participant will be paid in the form of an annuity for the participant's lifetime that is the actuarial equivalent of the participant's single sum amount, and that commences on the payment date.

A participant who elects, or is deemed to have elected, either the straight life annuity or the joint and survivor annuity described above may, in accordance with procedures established by the Committee, change his election to the other annuity option at any time prior to the payment date.

Unless otherwise provided in a participant agreement, if a participant dies before the payment date, a single sum distribution equal to the value of the participant's benefit that otherwise would have been payable under the SERP will be paid to the participant's designated beneficiary as soon as administratively practicable following the participant's death. Notwithstanding the foregoing, distribution of any non-grandfathered benefit that is made as a result of a termination of employment for a reason other than death, to persons who are "specified employees" under Internal Revenue Code Section 409A and guidance thereunder (basically, executive officers) must be deferred until the earlier of (i) the first day of the seventh month following the participant's termination of employment or (ii) the date of the participant's death. If a participant is involuntarily terminated following or incident to a change in control, the participant shall automatically become fully vested in his or her benefit under the SERP and such benefits shall become payable.

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Calculation of Benefits Potentially Payable to our Named Executive Officers under the SERP if a Triggering Event had Occurred as of December 30, 2016

The lump sum or annuity amounts that would have been payable under the SERP to each of our Named Executive Officers if they had become eligible for benefits as of December 30, 2016 are set forth below. Also set forth below are the payments that would have been made to each Named Executive Officer's designated beneficiary if the officer had died December 30, 2016.

For Mr. Marsh, the lump sum amount would have been $2,064,401. Alternatively, Mr. Marsh could have elected to receive a lump sum of $1,656,179 as of December 30, 2016 and monthly payments of $2,348 commencing January 1, 2017 for the remainder of his lifetime. In the event Mr. Marsh had been eligible to receive benefits and had elected to receive the aforementioned monthly annuity, his designated beneficiary would have received monthly payments of $1,409 for up to 15 years upon Mr. Marsh's death. If Mr. Marsh had died December 30, 2016 before becoming eligible for benefits, his beneficiary would have been entitled to the full lump sum payment of $2,064,401.

For Mr. Addison, the lump sum amount would have been $751,667. Alternatively, Mr. Addison could have elected to receive a lump sum of $691,163 as of December 30, 2016 and monthly payments of $316 commencing January 1, 2017 for the remainder of his lifetime. In the event Mr. Addison had been eligible to receive benefits and had elected to receive the aforementioned monthly annuity, his designated beneficiary would have received monthly payments of $189 for up to 15 years upon Mr. Addison's death. If Mr. Addison had died December 30, 2016 before becoming eligible for benefits, his beneficiary would have been entitled to the full lump sum payment of $751,667.

For Mr. Byrne, the lump sum amount would have been $994,049. Alternatively, Mr. Byrne could have elected to receive a lump sum of $817,663 as of December 30, 2016 and monthly payments of $934 commencing January 1, 2017 for the remainder of his lifetime. In the event Mr. Byrne had been eligible to receive benefits and had elected to receive the aforementioned monthly annuity, his designated beneficiary would have received monthly payments of $560 for up to 15 years upon Mr. Byrne's death. If Mr. Byrne had died December 30, 2016 before becoming eligible for benefits, his beneficiary would have been entitled to the full lump sum payment of $994,049.

For Mr. Lindsay, the lump sum amount would have been $307,519. Mr. Lindsay was not eligible for the alternative election providing for a reduced lump sum and lifetime monthly payments. If Mr. Lindsay had died December 30, 2016 before becoming eligible for benefits, his beneficiary would have been entitled to the full lump sum payment of $307,519.

For Mr. Kissam, the lump sum amount would have been $212,243. Alternatively, Mr. Kissam could have elected to receive a lump sum of $195,926 as of December 30, 2016 and monthly payments of $79 commencing January 1, 2017 for the remainder of his lifetime. In the event Mr. Kissam had been eligible to receive benefits and had elected to receive the aforementioned monthly annuity, his designated beneficiary would have received monthly payments of $47 for up to 15 years upon Mr. Kissam's death. If Mr. Kissam had died December 30, 2016 before becoming eligible for benefits, his beneficiary would have been entitled to the full lump sum payment of $212,243.

Executive Deferred Compensation Plan

The EDCP is described in the narrative following the 2016 Nonqualified Deferred Compensation table on page 47. As discussed in that section, amounts deferred under the EDCP are required to be paid, or begin to be paid, as soon as practicable following the earliest of a participant's death, separation from service, or with respect to pre-2005 deferrals and hypothetical earnings thereon, disability.

The "Aggregate Balance at Last FYE" column of the 2016 Nonqualified Deferred Compensation table on page 47 shows the amounts that would have been payable under the EDCP to each of our Named Executive Officers, as of December 30, 2016, (i) with respect to amounts payable at a date certain prior to separation from service, death, or, as to pre-2005 deferrals and hypothetical earnings thereon, disability, and (ii) with respect to amounts payable after separation from service, death, or, as to pre-2005 deferrals and hypothetical earnings thereon, disability, if they had been paid using the single sum form of payment. If the Named Executive Officers instead chose payment of the deferrals in annual installments, the annual installment payments over the payment periods selected by the Named Executive Officers are estimated as set forth below: Mr. Marsh — $697,130; Mr. Addison — $318,133; Mr. Byrne — $479,576; Mr. Lindsay — $687,020; Mr. Kissam — $70,407.

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Discussions of Plans are Summaries Only

The discussions of our various compensation plans in this "Executive Compensation" section of the Proxy Statement are merely summaries of the Plans and do not create any rights under any of the Plans and are qualified in their entirety by reference to the Plans themselves.

DIRECTOR COMPENSATION

Board Fees

Our Board reviews director compensation every year with guidance from the Nominating and Governance Committee. In making its recommendations, the Committee is required by our Governance Principles to consider that compensation should fairly pay directors for work required in a company of our size and scope, compensation should align directors' interests with the long-term interests of shareholders, and the compensation structure should be transparent and easy for shareholders to understand. We also consider the risks inherent in board service. Approximately every other year, the Nominating and Governance Committee considers relevant publicly available data and information provided by management's compensation consultant in making compensation recommendations. The Committee may also consider recommendations from our Chairman and Chief Executive Officer. Officers who are also directors do not receive additional compensation for their service as directors.

Effective July 1, 2016, annual director compensation increased from $193,000 to $219,000. Our annual director compensation, taking into account the mid-year adjustment, is structured as follows for non-employee directors:

- $219,000 in annual fees, consisting of a $131,400 stock retainer which is paid in shares of our common stock and an $87,600 cash retainer. The stock retainer and the cash retainer are generally payable on a quarterly basis. However, an additional payment was made in August, 2016, as a result of the mid-year adjustment in compensation.

- Committee Chair and Lead Director annual leadership retainer fees, payable in cash, in the following additional amounts: Lead Director — $25,000 (formerly $18,000), Audit Committee Chair — $15,000 (formerly $14,000), Compensation Committee Chair — $12,000 (formerly $8,000), Nominating and Governance Committee Chair — $10,000 (formerly $8,000), Nuclear Oversight Committee Chair — $12,000 (formerly $8,000). A director may only earn one annual leadership retainer fee in the form of either a Committee Chair retainer fee or the Lead Director retainer fee. Such additional Committee Chair and Lead Director retainer fees are also generally payable on a quarterly basis.

Due to the July 1, 2016 effective date of our director compensation increase, the amounts shown on the 2016 Director Compensation Table on page 59 are less than those outlined above.

All director compensation is pro-rated for any year of partial service. The annual stock retainer and all fees payable in cash may be deferred at the director's election pursuant to the terms of the Director Compensation and Deferral Plan discussed below. Beginning in 2015, non-employee directors are also permitted to choose to defer all or a portion of their annual cash retainer fees and all (but not less than all) of their annual stock retainer fees under the EDCP instead of the Director Compensation and Deferral Plan. See "Executive Compensation – Executive Deferred Compensation Plan" beginning on page 47.

Director Compensation and Deferral Plan

Since January 1, 2001, non-employee directors have had the option to defer annual stock and cash retainer fees pursuant to the terms of the SCANA Director Compensation and Deferral Plan. Amounts deferred by directors in previous years under the SCANA Voluntary Deferral Plan continue to be governed by that Plan.

Under the Director Compensation and Deferral Plan, instead of receiving quarterly payments of the stock retainer, a director may make an annual irrevocable election to defer all or a portion of the stock retainer into an investment in our common stock, with distribution from the Plan to be ultimately payable in shares of our common stock. A director also may elect to defer all or a portion of all other fees into an investment in our common stock or into a growth increment ledger which is credited with growth increments based on the prime interest rate charged from time to time by Wells Fargo Bank, N.A., as determined by us, with distribution from the Plan to be ultimately payable in cash or stock as the Plan may dictate. Amounts

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payable in our common stock accrue earnings during the deferral period at our dividend rate. All dividends attributable to shares of our common stock credited to each director's stock ledger account will be converted to additional credited shares of our common stock as though reinvested as of the next business day after the dividend is paid. These dividends are included in the number of hypothetical shares reflected for each director in footnote 2 to the "Security Ownership of Management" table on page 23. Directors do not have voting rights with respect to shares credited to their accounts under the Plan. A director's growth increment ledger will be credited on the first day of each calendar quarter, with a growth increment computed on the average balance in the director's growth increment ledger during the preceding calendar quarter. The growth increment will be equal to the amount in the director's growth increment ledger multiplied by the average interest rate we select during the preceding calendar quarter times a fraction the numerator of which is the number of days during such quarter and the denominator of which is 365. Growth increments will continue to be credited until all of a director's benefits have been paid out of the Plan.

We establish a ledger account for each director that reflects the amounts deferred on his or her behalf and the deemed investment of such amounts into a stock ledger account or a growth investment ledger account. Each ledger account will separately reflect the pre-2005 and post-2004 deferrals and earnings thereon, and the portion of the post-2004 deferrals and earnings thereon payable at a date certain and the portion payable when the director separates from service from the Board. In this discussion, we refer to pre-2005 deferrals as the "pre-2005 ledger account" and to post-2004 deferrals as the "post-2004 ledger account."

Directors may elect for payment of any post-2004 deferrals to be deferred until the earlier of separation from service from the Board for any reason or a date certain, subject to any limitations we may choose to apply at the time of election. If a participant does not make a payment election with respect to amounts deferred for any deferral period, such deferrals will be paid in a lump sum payment as soon as practicable after the director's separation from service from the Board.

Subject to the acceleration provisions of the Plan and Board approval with respect to pre-2005 deferrals, a director may elect an additional deferral period of at least 60 months with respect to any previously deferred amount credited to his or her post-2004 ledger account that is payable at a date certain, and an additional deferral period of at least 12 months for each separate deferral credited to his or her pre-2005 ledger account. With respect to amounts deferred until separation from service from the Board, directors may also elect a new manner of payment with respect to any previously deferred amounts, provided that, in the case of amounts credited to post-2004 ledger accounts that are payable on separation from service from the Board, payments are delayed for 60 months from the date payments would otherwise have commenced absent the election.

Amounts credited to directors' post-2004 ledger accounts that are scheduled to be paid at a date certain will be paid in the form of a single sum payment as soon as practicable after the date certain. With respect to amounts credited to pre-2005 ledger accounts, and amounts credited to post-2004 ledger accounts that are scheduled to be paid on separation from service from the Board, directors must irrevocably elect (subject to certain permitted changes) to have payment made in accordance with one of the following distribution forms:

- a single sum payment;
- a designated number of installments payable monthly, quarterly or annually, as elected (and in the absence of an election, annually), over a specified period not in excess of 20 years; or
- in the case of a post-2004 ledger account, payments in the form of annual installments with the first installment being a single sum payment of 10% of the post-2004 ledger account determined immediately prior to the date such payment is made and with the balance of the post-2004 ledger account being paid in annual installments over a total specified period not in excess of 20 years.

Such payments will be paid or commence to be paid as soon as practicable after the conclusion of the deferral period elected.

Notwithstanding any payment election made by a director:

- payments will be paid, or begin to be paid, as soon as practicable following the director's separation from service from the Board for any reason except as otherwise provided below;
- if a director dies prior to the payment of all or a portion of the amounts credited to his or her ledger account, the balance of any amount payable will be paid in a cash lump sum to his designated beneficiaries;

- if a director ceases to be a non-employee director but thereafter becomes our employee, all pre-2005 ledger accounts will be paid as soon as practicable after he or she becomes our employee in a single lump sum payment and all post-2004 ledger accounts will be paid as soon as practicable after he or she has incurred a separation from service as a nonemployee director (as determined in accordance with Internal Revenue Code Section 409A);

- if a director's post-2004 ledger account balance is less than $100,000 ($5,000 for pre-2005 ledger accounts) at the time for payment specified, such amount will be paid in a single payment; and

- in the case of any post-2004 ledger accounts that are payable on separation from service from the Board and that are subject to an additional deferral period of 60 months as a result of the modification of the manner of payment, no payment attributable to any post-2004 ledger accounts will be accelerated to a date earlier than the expiration of the 60 month period.

We, at our sole discretion, may alter the timing or manner of payment of deferred amounts if the director establishes, to our satisfaction, an unanticipated and severe financial hardship that is caused by an event beyond the director's control. In such event, we may:

- provide that all, or a portion of, the amount previously deferred by the director immediately be paid in a lump sum cash payment;

- provide that all, or a portion of, the installments payable over a period of time immediately be paid in a lump sum cash payment; or

- provide for such other installment payment schedules as we deem appropriate under the circumstances.

For pre-2005 ledger accounts, severe financial hardship will be deemed to have occurred in the event of the director's or a dependent's sudden, lengthy and serious illness as to which considerable medical expenses are not covered by insurance or relative to which there results a significant loss of family income, or other unanticipated events of similar magnitude. For post-2004 ledger accounts, severe financial hardship will be deemed to have occurred from a sudden or unexpected illness or accident of the director or the director's spouse, beneficiary or dependent, loss of the director's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the director's control.

During 2016, Ms. Miller and Messrs. Micali, Roquemore, Sloan and Stowe elected to defer 100% of their compensation and earnings and Messrs. Aliff, Bennett, Cecil and Hagood deferred a portion of their earnings under either or both of the Director Compensation and Deferral Plan and/or the Executive Deferred Compensation Plan.

As discussed under "Executive Compensation — Executive Deferred Compensation Plan" beginning on page 47, in 2014, we amended the EDCP to allow non-employee directors, who have met our minimum share ownership guidelines and who have not deferred such fees under the Director Deferral and Compensation Plan to defer all or a portion of their annual cash retainer fees and all (but not less than all) of their annual stock retainer fees into the EDCP, with payments ultimately to be paid in cash. Non-employee directors first became eligible to participate in the EDCP in 2015.

Endowment Plan

In July 2013, the Board closed the SCANA Director Endowment Plan to new participants effective January 1, 2013 after considering management's recommendation that such a plan may not be perceived as a best corporate governance practice. However, for eligible participants, the SCANA Director Endowment Plan provides for us to make tax deductible, charitable contributions totaling $500,000 to institutions of higher education designated by the director. The Plan was intended to reinforce our commitment to quality higher education and to enhance our ability to attract and retain qualified directors. A portion is contributed upon retirement of the director and the remainder upon the director's death. As of December 31, 2016, the cash obligation under the Plan was $7,600,000 pre-tax and $4,693,000 after-tax (assuming a 38.25% tax rate). The Plan is funded through insurance policies on the lives of certain of the participating directors. The 2016 premium for such insurance was $34,835. Currently the premium estimate for 2017 is $34,835.

Designated institutions of higher education in South Carolina, North Carolina and Georgia must be approved by our Chief Executive Officer. Institutions in other states must be approved by the Compensation Committee. The designated institutions are reviewed on an annual basis by the Chief Executive Officer to assure compliance with the intent of the Plan.

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Discussions of Plans are Summaries Only

The discussions of our various plans, including the Director Compensation and Deferral Plan and the Director Endowment Plan, are merely summaries of the Plans and do not create any rights under any of the Plans, and are qualified in their entirety by reference to the Plans themselves.

2016 DIRECTOR COMPENSATION TABLE

The following table sets forth the compensation we paid to each of our non-employee directors in 2016.

Name (a)	Fees Earned or Paid in Cash[(1)] ($) (b)	Stock Awards ($)[(2)] (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)[(3)] (f)	All Other Compensation ($) (g)	Total ($) (h)
G. E. Aliff	$ 89,900	$123,600	—	—	—	—	$213,500
J. A. Bennett	$ 88,400	$123,600	—	—	$3,867	—	$215,867
J. F.A.V. Cecil	$ 82,400	$123,600	—	—	—	—	$206,000
S. A. Decker	$ 82,400	$123,600	—	—	—	—	$206,000
D. M. Hagood	$101,900	$123,600	—	—	—	—	$225,500
J. M. Micali	$ 91,400	$123,600	—	—	—	—	$215,000
L. M. Miller	$ 82,400	$123,600	—	—	—	—	$206,000
J. W. Roquemore	$ 92,400	$123,600	—	—	—	—	$216,000
M. K. Sloan	$ 86,400	$123,600	—	—	—	—	$210,000
H. C. Stowe [(4)]	$ 47,600	$ 57,900	—	—	$ 605	—	$106,105
A. Trujillo	$ 82,400	$123,600	—	—	—	—	$206,000

(1) Cash retainer fees greater than $82,400 ($38,600 for Mr. Stowe) represent quarterly leadership fees for directors holding a Committee Chair or Lead Director position.

(2) The annual stock retainer is required to be paid quarterly in shares of our common stock. The quarterly stock retainer shares for the directors were issued on January 14, 2016, at a weighted average purchase price of $60.47, April 14, 2016, at a weighted average purchase price of $69.38, July 14, 2016, at a weighted average purchase price of $73.93, August 19, 2016, at a weighted average purchase price of $71.55 and October 14, 2016, at a weighted average purchase price of $68.37. The August stock retainer represents the mid-year increase to director compensation.

(3) Represents above market earnings on Mr. Bennett's previous cash deferrals into the cash deferral account ($2,956) and into the now closed Voluntary Deferral Plan ($911), and Mr. Stowe's cash deferrals into the cash deferral account ($605).

(4) Mr. Stowe no longer served on the Board of Directors following the 2016 Annual Meeting held on April 28, 2016.

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PROPOSAL 2 — ADVISORY (NON-BINDING) VOTE TO APPROVE EXECUTIVE COMPENSATION

Section 14A of the Securities Exchange Act of 1934 (the "1934 Act") requires that, at least every three years at the annual meeting of shareholders, we must submit a separate resolution subject to a non-binding shareholder advisory vote to approve the compensation of our Named Executive Officers as disclosed in this proxy statement pursuant to Item 402 of Regulation S-K under the 1934 Act.

This proposal gives you as a shareholder the opportunity to vote for, against, or abstain from voting, on the following resolution:

> "RESOLVED, that the compensation paid to the Company's Named Executive Officers, as disclosed pursuant to Item 402 of Regulation S-K, including the 'Compensation Discussion and Analysis,' compensation tables and narrative discussion is hereby APPROVED."

Because your vote is advisory, it will not be binding on our Board and may not be construed as overruling any decision by the Board, nor to create or imply any additional fiduciary duty of the Board. However, the Board will review the voting results, and may, as it did with respect to the results of the vote in 2014, in its sole discretion, take into account the outcome of the vote when considering future Named Executive Officer compensation.

Shareholders are encouraged to review carefully the "Executive Compensation" section of this Proxy Statement for a detailed discussion of our executive compensation program.

Board of Directors' Recommendation

Our overall executive compensation policies and procedures are described in the "Executive Compensation" section, including the tabular disclosure regarding Named Executive Officer compensation (together with the accompanying narrative disclosure) in this Proxy Statement. Our compensation policies and procedures are centered on a pay-for-performance approach that links total rewards to achievement of corporate business unit and individual goals, and are designed to be aligned with the long-term interests of our shareholders, as described in the "Executive Compensation" section. As previously discussed, we have designed our compensation program to reward senior executive officers for their individual and collective performance and for our collective performance in achieving target goals for earnings per share and total shareholder return and other annual and long-term business objectives. We believe our program performs a vital role in keeping executives focused on improving our performance and enhancing shareholder value while rewarding successful individual executive performance in a way that helps to assure retention.

The Compensation Committee, which is comprised entirely of independent directors, oversees our executive compensation program and continually monitors our policies to ensure that they continue to emphasize programs that reward executives for results that are consistent with shareholder interests.

Our Board and our Compensation Committee believe that our commitment to responsible compensation practices justifies a vote by shareholders "FOR" the resolution approving the compensation of our Named Executive Officers as disclosed in this Proxy Statement.

THE BOARD OF DIRECTORS UNANIMOUSLY RECOMMENDS A VOTE "FOR" APPROVAL OF THE RESOLUTION RELATING TO COMPENSATION OF OUR NAMED EXECUTIVE OFFICERS.

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PROPOSAL 3 — ADVISORY (NON-BINDING) VOTE ON THE FREQUENCY OF THE EXECUTIVE COMPENSATION VOTE

Section 14A of the 1934 Act also requires that, at least every six years at the annual meeting of shareholders, we must submit a separate resolution subject to a non-binding shareholder advisory vote to determine whether shareholders believe we should submit the foregoing resolution relating to the compensation of our Named Executive Officers at our annual meeting every year, every two years, or every three years. Shareholders were last given the opportunity to vote on the non-binding resolution on the frequency of the vote on executive compensation in 2011. Accordingly, pursuant to the requirements of Section 14A of the 1934 Act, shareholders are again being given the opportunity to vote on the non-binding resolution on the frequency of the vote on executive compensation at the Annual Meeting. Because your vote is advisory, it will not be binding on our Board and may not be construed as overruling any decision by the Board, nor to create or imply any additional fiduciary duty of the Board. However, the Board may, in its sole discretion, take into account the outcome of the vote in determining the frequency with which it will submit the resolution on executive compensation to shareholders.

We ask for your advisory vote to choose among the following three alternatives on frequency of the executive compensation vote. You may only choose one of the three alternatives: One Year, Two Years, Three Years, or you may abstain from voting.

Board of Directors' Recommendation

At the 2011 Annual Meeting, consistent with the Board of Directors' recommendation of a three-year frequency, more votes were cast in favor of a three-year frequency than either of the other frequency options. The directors took into consideration its reasons for the recommendation of a three-year frequency and the results of the 2011 vote, and set the frequency at every three years. The frequency of the vote has remained at every three years since that time. However, the Board of Directors has over the past six years taken into consideration that the prevailing practice among most large corporations is to provide for a non-binding advisory vote on executive compensation every year. The Board also took into consideration that in the 2011 vote, the three year option received the most votes by a small margin and the votes were closely divided between the one and three year options. We are committed to good corporate governance practices, and recognize that proxy advisory firms and certain of our largest institutional investors generally recommend annual say-on-pay votes. Therefore, our Board is recommending a say-on-pay frequency of one year.

THE BOARD OF DIRECTORS RECOMMENDS THAT YOU CHOOSE A FREQUENCY OF ONE YEAR FOR THE SHAREHOLDER ADVISORY VOTE ON APPROVAL OF THE COMPANY'S EXECUTIVE COMPENSATION.

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AUDIT COMMITTEE REPORT

In connection with the December 31, 2016 financial statements, the Audit Committee (i) reviewed and discussed the audited financial statements with management; (ii) discussed with the independent public accountants those matters required to be discussed by Auditing Standard No. 16, as adopted by the Public Company Accounting Oversight Board; (iii) received the written disclosures and the letter from the independent accountants required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communications with the Audit Committee concerning independence; and (iv) discussed with the independent accountant the independent accountant's independence. Based upon these reviews and discussions, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016 for filing with the Securities and Exchange Commission.

Mr. Gregory E. Aliff (Chairman)
Mr. James A. Bennett
Mr. John F. A. V. Cecil
Mr. James M. Micali
Ms. Lynne M. Miller

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PROPOSAL 4 — APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Deloitte & Touche LLP served as our independent registered public accounting firm for the year ended December 31, 2016, and the Audit Committee has appointed Deloitte & Touche LLP to serve as our independent registered public accounting firm to audit our 2017 financial statements. Shareholders are being asked to approve this appointment at the Annual Meeting.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" APPROVAL OF DELOITTE & TOUCHE LLP'S 2017 APPOINTMENT.

Unless you indicate to the contrary, the persons identified as proxies on the accompanying proxy card intend to vote the shares represented by your proxy to approve the appointment of Deloitte & Touche LLP as the independent registered public accounting firm to audit our 2017 financial statements.

Representatives of Deloitte & Touche LLP are expected to be present at the Annual Meeting and available to make such statements as they may desire and to respond to appropriate questions from shareholders.

Pre-Approval of Auditing Services and Permitted Non-Audit Services

Our Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered public accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee for approval at its next scheduled meeting.

Independent Registered Public Accounting Firm's Fees

The following table sets forth the aggregate fees billed to SCANA and its subsidiaries for the fiscal years ended December 31, 2016 and 2015 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu and their respective affiliates.

	2016	2015
Audit Fees(1)	$2,857,000	$2,670,000
Audit Related Fees(2)	$ 171,710	$ 139,945
Tax Fees	$ —	$ —
All Other Fees	$ —	$ —
Total Fees	$3,028,710	$2,809,945

(1) Fees for Audit Services billed for 2016 and 2015 consisted of audits of annual financial statements, comfort letters for securities underwriters, statutory and regulatory audits, consents and other services related to Securities and Exchange Commission filings, and accounting research.

(2) Fees primarily for employee benefit plan audits and, in 2015, for non-statutory audit services.

In 2016 and 2015, all of the Audit Fees and Audit Related Fees were approved by the Audit Committee.

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PROPOSAL 5 — APPROVAL OF BOARD-PROPOSED AMENDMENTS TO ARTICLE 8 OF OUR ARTICLES OF INCORPORATION TO DECLASSIFY THE BOARD OF DIRECTORS AND PROVIDE FOR THE ANNUAL ELECTION OF ALL DIRECTORS

Background of the Proposal

Our Articles of Incorporation currently provide for a classified Board of Directors divided into three classes, with each class being elected for a three-year term. In 2012 and 2013, we received shareholder proposals recommending the declassification of our Board of Directors. In 2012, 38% of our outstanding shares voted in favor of the proposal, and in 2013, 44% of our outstanding shares voted in favor of the proposal. We also received a shareholder proposal for our 2014 Annual Meeting seeking a shareholder vote on declassification. In light of the apparent growing shareholder support for declassification, the Board proposed amendments to our Articles of Incorporation to effect declassification and recommended that our shareholders approve such amendments at the 2014 Annual Meeting. Based on our agreement to submit a Board proposal on declassification to shareholders, the shareholder proposal for the 2014 Annual Meeting was withdrawn. We resubmitted a Board declassification proposal at each of the 2015 and 2016 Annual Meetings.

At the 2014, 2015 and 2016 Annual Meetings, 62%, 63% and 64%, respectively, of our outstanding shares voted in favor of the proposal, but shareholder support is still significantly less than the 80% affirmative vote of outstanding shares required to adopt the amendment.

Our Board is committed to strong corporate governance practices. In considering the results of the shareholder votes on the 2012 – 2016 proposals, as well as the support of institutional investor groups for annual election of directors, the Board again took into account the advantages and disadvantages of a classified Board. In favor of retaining the classified board structure, the Board noted that: a classified board structure provides valuable stability and continuity of leadership; a classified board structure enables us to recruit high quality directors who are willing to invest the time and energy necessary to understand our business, technology, competitive environment and strategic goals; and a classified board structure helps protect shareholder value in case of an unsolicited takeover proposal at an unfair price. In favor of declassification, the Board noted that declassification would allow our shareholders to evaluate all directors annually and would be consistent with a view that a declassified board is a corporate governance best practice. The Board also considered that many U.S. public companies have eliminated their classified board structures in recent years based on the perception of a growing number of investors that annual election of directors is the primary means for shareholders to influence corporate governance policies and to increase board accountability.

In February 2017, the Board decided to again propose amendments to Article 8 of our Articles of Incorporation to declassify the Board and provide for the annual election of all directors, and to recommend that our shareholders vote in favor of the amendments.

Proposed Amendments to Article 8 of the Articles of Incorporation

Under the proposed amendments, the annual election of directors would be phased in gradually to assure a smooth transition. If the amendments are adopted, they would become effective upon our filing of Articles of Amendment with the South Carolina Secretary of State following the Annual Meeting. Accordingly, directors elected at the 2018 annual meeting and thereafter would be elected to one-year terms. Consistent with our Articles of Incorporation as in effect for the 2017 Annual Meeting, directors to be elected at the 2017 Annual Meeting will be elected to serve three-year terms, expiring at the 2020 annual meeting. Directors who were elected at the 2016 annual meeting will continue to serve their current terms until the 2019 annual meeting, and directors who were elected at the 2015 annual meeting will continue to serve their current terms until the 2018 annual meeting. Article 8 of our Articles of Incorporation would also be amended to delete other references to classification of the Board and to provide that a director elected to fill a newly created directorship or vacancy would serve until the next annual meeting of shareholders.

If the proposed amendments to Article 8 of our Articles of Incorporation are not adopted by shareholders, the Board of Directors will remain classified.

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Text of the Proposed Amendments

The text of the proposed amendments to our Articles of Incorporation is as follows:

8.A. The number of directors of the corporation that shall constitute the entire Board of Directors shall be fixed from time to time by or pursuant to the provisions of the By-laws of the corporation. Any such provision shall continue in effect unless and until changed by the Board of Directors, but no such changes shall affect the term of any director then in office. Upon the adoption of this Section 8.A., Directors elected prior to the 2018 annual meeting of shareholders shall continue to be, and are, divided into three classes (I, II and III), as nearly equal in number as possible, and shall hold office for a term expiring at the annual meeting of shareholders held in the third year following the year of their respective elections and until their respective successors are elected and qualified. Directors elected at each annual meeting of shareholders commencing with the annual meeting of shareholders in 2018 shall hold office for a term of one year expiring at the next annual meeting of shareholders and until their respective successors are duly elected and qualified. No person who is not a salaried employee of the corporation who would attain the age of 70 or older during his term of service as a director shall be eligible to be elected a director. No person who is a salaried employee of the corporation who is age 65 or older shall be eligible to be elected a director, and the term of office of any director who is a salaried employee of the corporation shall expire upon such director attaining the age of 65 or upon retirement from active service with the corporation, whichever is earlier; provided, however, a person who is the Chief Executive Officer shall be eligible for election as a director even if such person is age 65 or older or has retired from active service with the corporation, and such person's term shall not expire as a result of attaining age 65 or prior retirement from active service with the corporation.

B. Newly created directorships resulting from any increase in the authorized number of directors or any vacancies in the Board of Directors resulting from death, resignation, retirement, disqualification, removal from office or any other cause shall be filled only by the Board of Directors then in office, although less than a quorum. Directors elected to fill a newly created directorship or other vacancies shall hold office until the next annual meeting of shareholders and until such director's successor has been elected and has qualified.

C. No changes to Article 8.C.

D. Notwithstanding the foregoing, if at any time the holders of any one or more classes or series of preferred stock issued by the corporation shall have the right, voting separately by class or series, to elect directors at an annual or special meeting of stockholders, the election, term of office, filling of vacancies and other features of such directorships shall be governed by the terms of these Restated Articles of Incorporation applicable thereto.

Required Vote and Board Recommendation

Our Articles of Incorporation require that, to be adopted, the proposed amendments must be approved by the affirmative vote of at least 80% of all outstanding shares of our common stock. If approved, the amendments will become effective upon filing of Articles of Amendment with the Secretary of State of South Carolina.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" APPROVAL OF THE AMENDMENTS TO ARTICLE 8 OF OUR ARTICLES OF INCORPORATION TO DECLASSIFY THE BOARD OF DIRECTORS AND PROVIDE FOR THE ANNUAL ELECTION OF ALL DIRECTORS.

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OTHER INFORMATION

Section 16(a) Beneficial Ownership Reporting Compliance

The rules of the Securities and Exchange Commission require that we disclose late filings of reports of beneficial ownership and changes in beneficial ownership of our common stock by our directors, executive officers and greater than 10% beneficial owners. To our knowledge, based solely on a review of Forms 3, 4 and 5 and amendments to such forms furnished to us and written representations made to us, all filings on behalf of such persons were made on a timely basis in 2016.

Shareholder Proposals and Nominations

In order to be considered for inclusion in our Proxy Statement and Proxy Card for the 2018 Annual Meeting of Shareholders, a shareholder proposal must be received by us at SCANA Corporation, c/o Corporate Secretary, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033, no later than November 24, 2017. Securities and Exchange Commission rules contain standards for determining whether a shareholder proposal is required to be included in a proxy statement.

Under our bylaws, any shareholder who intends to present a proposal or nominate an individual to serve as a director at the 2018 Annual Meeting must notify us no later than November 24, 2017 of the intention to present the proposal or make the nomination. The shareholder also must comply with the other requirements in the bylaws. Any shareholder may request a copy of the relevant bylaw provision by writing to the Office of the Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033.

Expenses of Solicitation

This solicitation of proxies is being made by our Board of Directors. We pay the cost of preparing, assembling and mailing this proxy soliciting material, including certain expenses of brokers and nominees who mail proxy material to their customers or principals. We have retained Georgeson, Inc., 480 Washington Boulevard, Jersey City, NJ 07310, to assist in the solicitation of proxies for the Annual Meeting and to provide ongoing governance advice and consultation at a fee of $18,000 plus associated costs and expenses.

In addition to the use of the mail, proxies may be solicited personally, by telephone, by email or other electronic means by our officers and employees without additional compensation.

View Proxy Statement and Annual Report Information through the Internet

IMPORTANT NOTICE REGARDING AVAILABILITY OF PROXY MATERIALS FOR SHAREHOLDER MEETING TO BE HELD ON APRIL 27, 2017:

The Proxy Statement, Notice of 2017 Annual Meeting, Annual Financial Statements, and Management's Discussion and Analysis and Related Annual Report Information are available through the Internet at www.scana.com under the caption "Investors — Financial Reports — Most Recent Reports."

SCANA shareholders may view proxy statements and annual report information at this website. If you choose to view proxy materials through the Internet, you may incur costs, such as telephone and Internet access charges, for which you will be responsible.

Availability of Form 10-K

We have filed with the Securities and Exchange Commission our Annual Report on Form 10-K for the fiscal year ended December 31, 2016. **A copy of the Form 10-K, including the financial statements and financial statement schedule and a list of exhibits, will be provided without charge to each shareholder to whom this proxy statement is delivered upon our receipt of a written request from such shareholder.** The exhibits to the Form 10-K also will be provided upon request and payment of copying charges. Requests for a copy of the Form 10-K should be directed to: **Bryant Potter, Manager-Investor Relations, SCANA Corporation, 220 Operation Way, Mail Code C103, Cayce, South Carolina 29033.**

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Incorporation by Reference

We file various documents with the Securities and Exchange Commission, some of which incorporate information by reference. This means that information we have previously filed with the Securities and Exchange Commission should be considered as part of the filing.

Neither the Compensation Committee Report nor the Audit Committee Report shall be deemed to be filed with the Securities and Exchange Commission or incorporated by reference into any of our filings under the Securities Exchange Act of 1934 or the Securities Act of 1933, unless specifically incorporated by reference therein.

References to Our Website Address

References to our website address throughout this Proxy Statement and the accompanying materials are for informational purposes only or to fulfill specific disclosure requirements of the Securities and Exchange Commission’s rules or the New York Stock Exchange Listing Standards. These references are not intended to, and do not, incorporate the contents of our website by reference into this Proxy Statement or the accompanying materials.

Directions to the Annual Meeting

From Charlotte: Take I-77 South to Exit 9-A (Garners Ferry Road). Follow the exit onto Garners Ferry Road under I-77. East Exchange Place is the first right turn off Garners Ferry Road immediately before Quality Inn & Suites. Follow to Leaside at the end of East Exchange Place. The parking lot is located in front of the building.

From Charleston: Take I-26 to I-77 North toward Charlotte. Take Exit 9-A and turn right at traffic light onto Garners Ferry Road. East Exchange Place is the first right turn off Garners Ferry Road immediately before Quality Inn & Suites. Follow to Leaside at the end of East Exchange Place. The parking lot is located in front of the building.

From Greenville: Take I-26 East toward Columbia/Charleston. Take Exit 116 onto I-77 North toward Charlotte. Take Exit 9-A and turn right at traffic light onto Garners Ferry Road. East Exchange Place is the first right turn off Garners Ferry Road immediately before Quality Inn & Suites. Follow to Leaside at the end of East Exchange Place. The parking lot is located in front of the building.

From Downtown (Columbia): Take US 378/76 East (Devine Street/Garners Ferry Road) past the Veterans Administration Hospital (also known as Dorn VA Medical Center) and under the I-77 overpass. East Exchange Place is the first right turn off Garners Ferry Road immediately before Quality Inn & Suites. Follow to Leaside at the end of East Exchange Place. The parking lot is located in front of the building.

Tickets to the Annual Meeting

An admission ticket or proof of share ownership as of the record date, March 1, 2017, is required to attend the Annual Meeting. If you plan to use the admission ticket, please remember to detach it from your proxy card before mailing your proxy card. If you forget to bring the admission ticket, you will be admitted to the meeting only if you are listed as a shareholder of record as of the close of business on March 1, 2017 and bring proof of identification. If you hold your shares through a stockbroker or other nominee, you must provide proof of ownership by bringing either a copy of the voting instruction card provided by your broker or nominee or a brokerage statement showing your share ownership on March 1, 2017.

If you are a shareholder of record and your shares are owned jointly and you need an additional ticket, you should contact the Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033, or call 803-217-7568.

SCANA CORPORATION

Gina Champion
Vice President
Corporate Secretary
Deputy General Counsel
March 24, 2017

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FINANCIAL APPENDIX

Index to Annual Financial Statements, Management's Discussion and Analysis and Related Annual Report Information:

Table of Contets

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Financial Appendix (or elsewhere herein) which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;
(2) legislative and regulatory actions, particularly changes related to electric and gas services, rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;
(3) current and future litigation;
(4) changes in the economy, especially in areas served by subsidiaries of SCANA;
(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;
(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;
(7) the loss of sales to distributed generation, such as solar photovoltaic systems or energy storage systems;
(8) growth opportunities for SCANA's regulated and other subsidiaries;
(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;
(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA's subsidiaries;
(11) changes in SCANA's or its subsidiaries' accounting rules and accounting policies;
(12) payment and performance by counterparties and customers as contracted and when due;
(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission, including nuclear generating facilities;
(14) the results of efforts to operate the Company's electric and gas systems and assets in accordance with acceptable performance standards, including the impact of additional distributed generation and nuclear generation;
(15) maintaining creditworthy joint owners for SCE&G's new nuclear generation project;
(16) the creditworthiness and/or financial stability of contractors for SCE&G's new nuclear generation project, particularly in light of adverse financial developments disclosed by Toshiba;
(17) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon quality and prices, for our construction program, operations and maintenance;
(18) the results of efforts to ensure the physical and cyber security of key assets and processes;
(19) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;
(20) the availability of skilled, licensed and experienced human resources to properly manage, operate, and grow the Company's businesses;
(21) labor disputes;
(22) performance of SCANA's pension plan assets and the effect(s) of associated discount rates;
(23) changes in tax laws and realization of tax benefits and credits, including production tax credits for new nuclear units, and the ability or inability to realize credits and deductions;
(24) inflation or deflation;
(25) changes in interest rates;
(26) compliance with regulations;
(27) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and
(28) the other risks and uncertainties described from time to time in the reports filed by SCANA or its subsidiaries with the SEC.

SCANA disclaims any obligation to update any forward-looking statements.

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DEFINITIONS

Abbreviations used in this Financial Appendix have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CB&I	Chicago Bridge & Iron Company N.V.
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CGT	Carolina Gas Transmission Corporation
CO_2	Carbon Dioxide
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of WEC and Stone and Webster
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker (decoupling mechanism)
CWA	Clean Water Act
DCGT	Dominion Carolina Gas Transmission LLC
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DRB	Dispute Resolution Board
DSM Programs	Demand Side Management Programs
ELG Rule	Federal effluent limitation guidelines for steam electric generating units
EMANI	European Mutual Association for Nuclear Insurance
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fluor	Fluor Corporation
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRC	Internal Revenue Code
IRS	United States Internal Revenue Service
kWh	Killowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities

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TERM	**MEANING**
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NASDAQ	The NASDAQ Stock Market, Inc.
NAV	Net Asset Value
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NO_X	Nitrogen Oxide
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
ROE	Return on Common Equity
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	SCANA Energy Marketing, Inc.
SCE&G	South Carolina Electric & Gas Company
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Spirit Communications	SCTG, LLC and its wholly-owned subsidiary SCTG Communications, Inc.
Stone & Webster	Prior to December 31, 2015, CB&I Stone & Webster, a subsidiary of CB&I. Effective December 31, 2015, Stone & Webster, a subsidiary of WECTEC, LLC, a wholly-owned subsidiary of WEC
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Toshiba	Toshiba Corporation, parent company of WEC
TSR	Total Shareholder Return
Unit 1	Nuclear Unit 1 at Summer Station
WEC	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

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SELECTED FINANCIAL AND OTHER STATISTICAL DATA

As of or for the Year Ended December 31,	2016	2015	2014	2013	2012
	(Millions of dollars, except statistics and per share amounts)				
Statement of Income Data					
Operating Revenues	$ 4,227	$ 4,380	$ 4,951	$ 4,495	$ 4,176
Operating Income	$ 1,153	$ 1,308	$ 1,007	$ 910	$ 859
Net Income	$ 595	$ 746	$ 538	$ 471	$ 420
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.9	142.9	141.9	138.7	131.1
Basic Earnings Per Share	$ 4.16	$ 5.22	$ 3.79	$ 3.40	$ 3.20
Diluted Earnings Per Share	$ 4.16	$ 5.22	$ 3.79	$ 3.39	$ 3.15
Dividends Declared Per Share of Common Stock	$ 2.30	$ 2.18	$ 2.10	$ 2.03	$ 1.98
Balance Sheet Data					
Utility Plant, Net	$ 14,324	$ 13,145	$ 12,232	$ 11,643	$ 10,896
Total Assets	$ 18,707	$ 17,146	$ 16,818	$ 15,127	$ 14,568
Total Equity	$ 5,725	$ 5,443	$ 4,987	$ 4,664	$ 4,154
Short-term and Long-term Debt	$ 7,431	$ 6,529	$ 6,581	$ 5,788	$ 5,707
Other Statistics					
Electric:					
Customers (Year-End)	709,418	698,372	687,800	678,273	669,966
Total sales (Million kWh)	23,458	23,102	23,319	22,313	23,879
Generating capability-Net MW (Year-End)	5,233	5,234	5,237	5,237	5,533
Territorial peak demand-Net MW	4,807	4,970	4,853	4,574	4,761
Regulated Gas:					
Customers, excluding transportation (Year-End)	906,883	881,295	859,186	837,232	818,983
Sales, excluding transportation (Thousand Therms)	890,113	875,218	973,907	921,533	798,978
Transportation customers (Year-End)	632	627	656	667	663
Transportation volumes (Thousand Therms)	674,999	791,402	1,786,897	1,729,399	1,559,542

For information on the impact of certain dispositions on selected financial data, see Note 1 to the consolidated financial statements.

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SCANA'S BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees of 5,910 as of February 20, 2017 and 5,829 as of February 19, 2016. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries described below, each of which is incorporated in South Carolina.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 709,000 customers and the purchase, sale and transportation of natural gas to approximately 358,000 customers (each as of December 31, 2016). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a unit power sales agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 550,000 residential, commercial and industrial customers (as of December 31, 2016). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

Nonregulated Businesses

SCANA Energy markets natural gas in the southeast and provides energy-related services. A division of SCANA Energy sells natural gas to approximately 450,000 customers (as of December 31, 2016) in Georgia's deregulated natural gas market.

SCANA Services, Inc. provides administrative and management services to SCANA's other subsidiaries.

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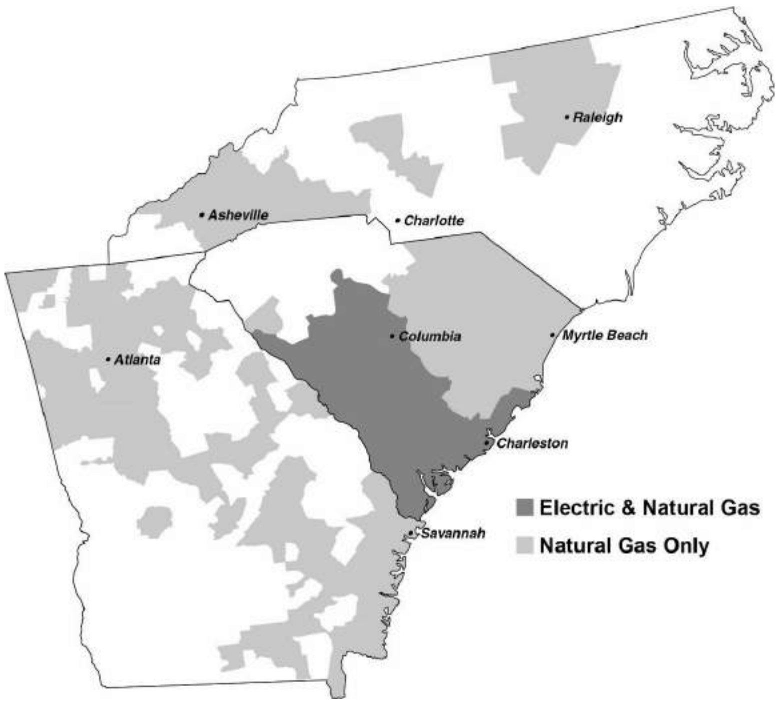
OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

The following map indicates areas where the Company's significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect amounts attributable to the Company's regulated and nonregulated operations and other nonregulated (including the holding company and the services company).

	2016	2015	2014
Net Income			
Regulated	98 %	72 %	98 %
Nonregulated operations	5 %	4 %	7 %
Other nonregulated	(3)%	24 %	(5)%
Assets			
Regulated	97 %	97 %	95 %
Nonregulated operations	1 %	1 %	2 %
Other nonregulated	2 %	2 %	3 %

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In the first quarter of 2015, SCANA closed on the sales of its interstate natural gas pipeline and telecommunications subsidiaries. Gains from these sales are included within Other. See Dispositions in Note 1 to the consolidated financial statements.

Key Earnings Drivers and Outlook

In 2016, companies announced plans to invest over $1.8 billion, with the expectation of creating approximately 7,000 jobs in the Company's South Carolina and North Carolina service territories. At December 31, 2016, South Carolina's unemployment rate was 4.3%, which is approximately 1.2% lower than the prior year. In addition, each of the Company's regulated businesses experienced positive customer growth year over year.

Over the next five years, key earnings drivers for the Company are expected to be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business and the level of growth of operation and maintenance, interest and other expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generate electricity and provide for its transmission, distribution and sale to approximately 709,000 customers (as of December 31, 2016) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity compared to other energy sources.

Embedded in the rates charged to customers is an allowed regulatory ROE. SCE&G's allowed ROE in 2016 was 10.25% for non-BLRA rate base and 10.5% for BLRA-related rate base. For BLRA-related rate base existing prior to 2016, SCE&G's allowed ROE was 11.0%.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and SCE&G has agreed to acquire an additional 5% ownership from Santee Cooper in increments beginning with the commercial operation date of Unit 2.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding certain disputes, and the EPC Contract was amended. The October 2015 Amendment became effective on December 31, 2015, and among other things, it resolved by settlement and release substantially all then-outstanding disputes between SCE&G and the Consortium. The October 2015 Amendment also provided SCE&G and Santee Cooper an option, subject to regulatory approvals, to fix the total amount to be paid to the Consortium for its entire scope of work on the project after June 30, 2015, subject to certain exceptions. In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units developed as a result of the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively, although recent communications from WEC indicate substantial completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits. However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to meet forecasted productivity and work force efficiency levels.

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The approved capital cost schedule includes incremental capital costs. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under any of several arrangements with other contractors or, were it determined to be prudent, halting the project, leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA. Any significant delay in the timing of construction or any determination by the SCPSC to disallow the recovery of costs would adversely impact results of operations, cash flows and financial condition.

The information summarized above, as well as additional information regarding uncertainties concerning WEC's ability to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project and other related matters, is further discussed in Note 2 and Note 10 to the consolidated financial statements.

Environmental

The results of recent elections may affect the pace at which federal environmental laws and regulations are enacted or how stringently their provisions are interpreted in the future. However, public sentiment surrounding air quality and water quality remains strong and is expected to continue unabated.

Over several years, SCE&G has made significant investments in constructing non-emitting generation (the New Units previously mentioned) and retiring certain coal-fired plants or converting them to burn natural gas. In addition, SCE&G expects to add the renewable energy from six new solar generating facilities at locations throughout its electric service territory over the next few years. The impact of these investments is expected to result in a significant shift toward non-emitting sources of fuel used to generate electricity in the future.

Generation Type	**2016 Actual**	**2021 Projected**
Nuclear	24.7 %	56.7 %
Hydro	3.3 %	3.4 %
Solar	— %	2.2 %
Total Non-emitting	**28.0 %**	**62.3 %**
Biomass	1.7 %	— %
Natural Gas	33.5 %	17.9 %
Coal	36.8 %	19.8 %
Total Generation	100.0 %	100.0 %

In addition, SCE&G and GENCO have made significant investments to install pollution control equipment at their remaining coal-fired plants. These investments, together with investments in non-emitting generation, have reduced their air emissions and are expected to result in additional reductions in the future.

Emissions, measured in thousands of tons

Year	**NO_X**	**SO_2**	**CO_2**
2005	27.0	107.9	18,778.7
2013	7.0	19.3	12,507.9
2014	7.6	16.8	13,984.6
2015	5.7	5.1	12,891.8
2016	5.4	2.7	11,567.4
2021*	3.2	1.2	7,062.5
% decrease from 2005 to 2021*	**88.1 %**	**98.9 %**	**62.4 %**

* Projected

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The status of significant environmental laws and regulations and certain initiatives undertaken to ensure compliance with them are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. In addition, uncertainties with respect to the New Units are described in Note 10 to the consolidated financial statements.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 907,000 retail customers (as of December 31, 2016) in portions of South Carolina and North Carolina in areas covering approximately 35,000 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory ROE for SCE&G of 10.25% and for PSNC Energy of 10.60% through October 31, 2016 and 9.7% thereafter.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company’s ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at generally low levels for several years. The supply of natural gas from the Marcellus shale basin has prompted companies unaffiliated with SCANA to propose a 550-mile pipeline that would bring natural gas from West Virginia to Virginia and North Carolina. This pipeline is expected to be completed in late 2019 and, if successful, it may drive economic development along its path, including areas within PSNC Energy’s service territory, and may serve to assist in keeping natural gas competitively priced in the region.

Gas Marketing

SCANA Energy markets natural gas in the southeast and provides energy-related services to customers, including, notably, retail customers in Georgia. Operating results for energy marketing are influenced by customer demand for natural gas and the ability to control costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, the availability of certain pipeline capacity to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the Georgia retail market. SCANA Energy sells natural gas to approximately 450,000 customers (as of December 31, 2016) throughout Georgia. This market is mature, resulting in lower margins and stiff competition. Competitors include affiliates of large energy companies as well as electric membership cooperatives, among others. SCANA Energy’s ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy’s operating results are sensitive to weather.

RESULTS OF OPERATIONS

Earnings and Dividends

Earnings and dividends were as follows:

	2016	2015	2014
Earnings per share	$ 4.16	$ 5.22	$ 3.79
Cash dividends declared per share	$ 2.30	$ 2.18	$ 2.10

On February 16, 2017, SCANA declared a quarterly cash dividend on its common stock of $0.6125 per share.

2016 vs 2015

Earnings per share decreased primarily due to the sales of CGT and SCI in 2015, higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense. These decreases were

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partially offset by higher electric and gas distribution margins, higher other income net of other expenses and higher energy marketing net income, as further described below.

2015 vs 2014

Earnings per share increased due to the sales of CGT and SCI in 2015, higher electric margins, lower operation and maintenance expenses and lower depreciation expense. These increases were partially offset by lower gas margins, higher property taxes, lower other income, higher interest expense, a higher effective tax rate and dilution from additional shares outstanding, as further described below.

The sales of CGT and SCI were closed in the first quarter of 2015. These subsidiaries operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. Therefore, CGT and SCI were not a part of the Company's core business. See Note 12 to the consolidated financial statements.

Electric Operations

Electric Operations for the Company is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric Operations operating income (including transactions with affiliates) was as follows:

Millions of dollars	2016	2015	2014
Operating revenues	$2,619.4	$2,557.1	$2,629.4
Fuel used in electric generation	576.1	660.6	799.3
Purchased power	63.7	52.1	80.7
Margin	1,979.6	1,844.4	1,749.4
Other operation and maintenance	526.1	497.1	494.8
Depreciation and amortization	286.5	277.3	300.3
Other taxes	210.4	194.5	186.7
Operating Income	$ 956.6	$ 875.5	$ 767.6

Electric operations can be significantly impacted by the effects of weather. SCE&G estimates the effects on its electric business of actual temperatures in its service territory as compared to historical averages to develop an estimate of electric margin revenue attributable to the effects of abnormal weather. Results in 2016 reflect warmer than normal weather in the second and third quarters and milder than normal weather in the first and fourth quarters. Results in 2015 reflect colder than normal weather in the first quarter, warmer than normal weather in the second and third quarters and milder than normal weather in the fourth quarter. Results in 2014 reflect colder than normal weather in the first quarter, hotter than normal weather in the second and third quarters and milder than normal weather in the fourth quarter.

2016 vs 2015

- Margin increased due to base rate increases under the BLRA of $60.7 million, the effects of weather of $22.1 million, residential and commercial customer growth of $22.1 million, higher industrial margin of $7.6 million and higher collections under the rate rider for pension costs of $13.5 million. These margin increases were partially offset by lower residential and commercial average use. The higher pension rider collections had no effect on net income as they were fully offset by the recognition, within other operation and maintenance expenses, of higher pension costs. Margin also increased due to downward revenue adjustments in 2015, pursuant to orders from the SCPSC, to apply $14.5 million as an offset to fuel cost recovery upon the adoption of new (lower) electric depreciation rates and by $5.2 million related to DSM Programs. These adjustments had no effect on net income in 2015 as they were fully offset by the recognition of $14.5 million of lower depreciation expense and by the recognition, within other income, of $5.2 million of gains realized upon the settlement of certain interest rate contracts.

- Other operation and maintenance expenses increased due to higher labor costs of $25.4 million, primarily due to increased pension cost associated with the higher pension rider collections and higher incentive compensation costs. Other operation and maintenance expenses also increased due to higher amortization of DSM program costs of $2.0 million.

- Depreciation and amortization increased primarily due to net plant additions.

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- Other taxes increased primarily due to higher property taxes on net plant additions.

2015 vs 2014

- Margin increased due to downward adjustments of $69.0 million in 2014, compared to downward adjustments of $19.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and DSM Programs. These adjustments had no effect on net income as they were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts, lower depreciation expense upon the adoption and implementation of revised depreciation rates as a result of an updated depreciation study and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve. Margin also increased due to base rate increases under the BLRA of $65.7 million and residential and commercial customer growth of $21.4 million. These increases were partially offset by $25.6 million due to the effects of weather, lower industrial margins of $14.6 million primarily due to variable price contracts, and lower collections under the rate rider for pension costs of $3.0 million. See Note 2 to the consolidated financial statements.

- Other operation and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider collections.

- Depreciation and amortization decreased by $28.7 million in 2015 due to the implementation of the above mentioned revised depreciation rates, $14.5 million of which was offset by downward revenue adjustments. This decrease in depreciation expense was partially offset by increases associated with net plant additions.

- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric operations margin above, by class, were as follows:

Classification	2016	2015	2014
Residential	8,140	7,978	8,156
Commercial	7,506	7,386	7,371
Industrial	6,265	6,201	6,234
Other	600	595	600
Total retail sales	22,511	22,160	22,361
Wholesale	947	942	958
Total Sales	23,458	23,102	23,319

2016 vs 2015

Retail sales volumes increased primarily due to the effects of weather and customer growth.

2015 vs 2014

Retail sales volumes decreased primarily due to the effects of weather, partially offset by customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas Distribution operating income (including transactions with affiliates) was as follows:

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Millions of dollars	2016	2015	2014
Operating revenues	$ 789.8	$ 811.7	$ 1,014.0
Gas purchased for resale	345.9	383.7	592.5
Margin	443.9	428.0	421.5
Other operation and maintenance	172.7	161.4	154.8
Depreciation and amortization	82.0	77.5	72.4
Other taxes	41.5	37.5	34.8
Operating Income	$ 147.7	$ 151.6	$ 159.5

The effect of abnormal weather conditions on gas distribution margin is mitigated by the WNA at SCE&G and the CUT at PSNC Energy as further described in Revenue Recognition in Note 1 of the consolidated financial statements. The WNA and CUT affect margins but not sales volumes.

2016 vs 2015

- Margin increased $11.5 million due to residential and commercial customer growth, $5.0 million due to an NCUC-approved rate increase effective November 2016 at PSNC Energy, and $1.1 million due to an SCPSC-approved increase in base rates under the RSA effective November 2016 at SCE&G. These increases were partially offset by lower average use of $4.1 million at SCE&G.

- Other operation and maintenance expenses increased due to higher labor costs of $6.7 million due primarily to higher incentive compensation costs.

- Depreciation and amortization increased due to net plant additions, partially offset by the implementation of SCPSC-approved revised (lower) depreciation rates at SCE&G of $1.1 million.

- Other taxes increased due to net plant additions.

2015 vs 2014

- Margin increased due to residential and commercial customer growth of $7.8 million partially offset by a decrease of $3.1 million due to an SCPSC-approved decrease in base rates at SCE&G under the RSA effective November 2014.

- Other operation and maintenance expenses increased due to higher labor costs, primarily due to incentive compensation.

- Depreciation and amortization increased due to net plant additions.

- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in MMBTU) related to gas distribution margin by class, including transportation, were as follows:

Classification (in thousands)	2016	2015	2014
Residential	40,142	39,090	46,207
Commercial	29,078	28,064	30,701
Industrial	19,364	20,101	20,343
Transportation gas	49,769	49,297	45,506
Total	138,353	136,552	142,757

2016 vs 2015

Residential and commercial firm sales volumes increased primarily due to customer growth. Commercial and industrial interruptible volumes decreased, and firm volumes increased, due to customers switching from interruptible to firm service at SCE&G. Industrial volumes decreased and transportation volumes increased due to customers switching to transportation only service.

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2015 vs 2014

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use, partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to a shift to transportation service from system supply and the impact of curtailments, partially offset by lower curtailments at PSNC Energy. Transportation volumes increased due to customers shifting to transportation-only service at SCE&G and increased sales for natural gas fired electric generation in PSNC Energy's territory.

Gas Marketing

Gas Marketing is comprised of the Company's nonregulated marketing operation, SCANA Energy, which operates in the southeast and includes Georgia's retail natural gas market. Gas Marketing operating revenues and net income were as follows:

Millions of dollars	2016	2015	2014
Operating revenues	$ 936.7	$ 1,146.7	$ 1,496.4
Net Income	29.8	27.6	31.0

2016 vs 2015

Operating revenues decreased due to the lower market price of natural gas and lower industrial sales volume. Net income increased primarily due to a weather-related increase in demand.

2015 vs 2014

Operating revenues decreased due to the lower market price of natural gas, weather-related changes in demand, lower industrial sales volume and lower market prices. Net income decreased primarily due to weather-related changes in demand, partially offset by lower cost of gas and lower costs of transportation to serve customers.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2016	2015	2014
Other operation and maintenance	$ 755.6	$ 715.3	$ 728.3
Depreciation and amortization	370.9	357.5	383.7
Other taxes	253.9	234.2	228.8

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in those discussions. Additional information is provided below.

2016 vs 2015

In addition to factors discussed in the electric operations and gas distribution segments, overall increases in other operating expenses were partially offset by the Company's sale of CGT in early 2015, which resulted in decreases in other operation and maintenance expenses of $2.2 million, depreciation and amortization of $0.7 million and other taxes of $0.5 million.

2015 vs 2014

In addition to factors discussed in the electric operations and gas distribution segments, the Company's sale of CGT in early 2015 resulted in decreases in other operation and maintenance expenses of $24.2 million, depreciation and amortization of $7.8 million and other taxes of $8 million.

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Net Periodic Benefit Cost

Other operation and maintenance expense includes net periodic benefit cost, which was recorded on the income statements and balance sheets as follows:

Millions of dollars	2016	2015	2014
Income Statement Impact:			
Employee benefit costs	$ 19.2	$ 5.3	$ 5.0
Other expense	0.9	1.1	0.2
Balance Sheet Impact:			
Increase in capital expenditures	5.3	3.9	0.5
Component of amount receivable from Summer Station co-owner	2.1	1.5	0.1
Increase (decrease) in regulatory assets	(4.6)	6.2	(3.2)
Net periodic benefit cost	$ 22.9	$ 18.0	$ 2.6

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were $2.0 million for retail electric operations and $1.0 million for gas operations for each period presented.

Other Income (Expense)

Other income (expense) includes the results of certain incidental non-utility activities of regulated subsidiaries, the activities of certain of the Company's non-regulated subsidiaries, and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. An equity portion of AFC is included in nonoperating income and a debt portion of AFC is included in interest charges (credits), both of which have the effect of increasing reported net income. Components of other income (expense) and AFC were as follows:

Millions of dollars	2016	2015	2014
Other income	$ 64.4	$ 74.5	$ 121.8
Other expense	(38.5)	(60.1)	(64.3)
Gain on sale of SCI, net of transaction costs	—	106.6	—
AFC - equity funds	29.4	27.0	32.7

2016 vs 2015

Other income decreased by $3.5 million due to lower gains on the sale of land and due to the recognition in 2015 of $5.2 million of gains realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). Other income also decreased by $3.9 million and other expenses decreased by $2.3 million due to the sale of SCI, and other income and other expenses decreased by $10.5 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. Other expenses decreased by $5.2 million due to lower contribution expenses. In 2015, other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC increased due to construction activity.

2015 vs 2014

Other income decreased due primarily to the recognition of $64.0 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). Other income also decreased by $18.3 million and other expenses decreased by $10.9 million due to the sale of SCI, and other income and other expenses increased by $12.7 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. In 2015, other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC decreased due to lower AFC rates.

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Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2016	2015	2014
Interest on long-term debt, net	$ 330.3	$ 311.3	$ 306.7
Other interest expense	12.0	6.5	5.7
Total	$ 342.3	$ 317.8	$ 312.4

Interest expense increased in each year primarily due to increased borrowings.

Income Taxes

Income tax expense decreased from 2015 to 2016 primarily due to lower income before taxes. Income tax expense increased from 2014 to 2015 primarily due to higher income before taxes. Income before taxes, income taxes and the effective tax rate were all higher in 2015 primarily due to the sales of CGT and SCI.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to meet contractual cash obligations in 2017 through internally generated funds and additional short- and long-term borrowings. The Company may also meet such obligations through the sale of equity securities. The Company expects that, barring a future impairment of the capital markets or its access to such markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

Due primarily to the availability of proceeds from the sale of two subsidiaries in the first quarter of 2015, the Company began using open market purchases for its stock plans at the end of January 2015. Prior to the use of open market purchases, SCANA common stock was acquired on behalf of participants in SCANA's Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares. This provided additional equity of approximately $14 million in 2015.

Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of the Company's or its rated operating companies' commonly monitored financial credit metrics and adverse developments with respect to nuclear construction could negatively affect the Company's debt ratings. This could cause the Company to pay higher interest rates on its long- and short-term indebtedness, and could limit the Company's access to capital markets and liquidity.

Cash provided from operating activities in 2015 reflects lower tax payments arising from Congress' extension of bonus deprecation provisions in 2014. Cash provided from operating activities in 2016 reflects significant tax benefits (reductions in income tax payments) arising from the deduction under Section 174 of the IRC of certain expenditures related to the design and construction of the New Units and the related claim of credits under Section 41 of the IRC. Similar tax benefits are expected to be claimed in the next several years as design and construction continues, and these cash flows are expected to continue to supplant portions of financing which would otherwise be obtained in the capital markets.

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Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.6 billion in 2016. Estimates of capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2017	2018	2019
SCE&G - Normal			
Generation	$ 138	$ 124	$ 148
Transmission & Distribution	180	205	207
Other	10	16	26
Gas	74	85	76
Common	4	3	9
Total SCE&G - Normal	406	433	466
PSNC Energy	332	242	182
Other	31	21	28
Total Normal	769	696	676
New Nuclear (including transmission) - SCE&G*	1,222	1,165	501
Cash Requirements for Construction*	1,991	1,861	1,177
Nuclear Fuel - SCE&G	80	89	111
Total Estimated Capital Expenditures*	$2,071	$1,950	$1,288

* Excludes the impact of the updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. See Note 10 to the consolidated financial statements.

Contractual cash obligations as of December 31, 2016 are summarized as follows:

Contractual Cash Obligations	Payments due by periods				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long- and short-term debt, including interest	$ 13,976	$ 1,292	$ 2,002	$ 1,257	$ 9,425
Capital leases	26	5	14	2	5
Operating leases	116	30	59	6	21
Purchase obligations	3,869	2,387	1,481	1	—
Other commercial commitments	3,639	899	1,532	613	595
Total	$ 21,626	$ 4,613	$ 5,088	$ 1,879	$ 10,046

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent. SCE&G has agreed to acquire an additional 5% ownership in the New Units and has included $850 million for this purpose in other commercial commitments. See also New Nuclear Construction in Note 10 to the consolidated financial statements.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

Unrecognized tax benefits of approximately $219 million have been excluded from the table above due to uncertainty as to the timing of future payments. For additional information, see Note 5 to the consolidated financial statements.

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In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $11.1 million in 2016, and such annual payments are expected to be the same or increase to as much as $15.9 million in the future.

The Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. The Company is also party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash collateral. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at Quantitative and Qualitative Disclosures About Market Risk and Note 6 to the consolidated financial statements. As of December 31, 2016, the Company had posted $29.0 million in cash collateral related to interest rate derivative contracts.

The Company has a legal obligation associated with the decommissioning and dismantling of Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

Financing Limits and Related Matters

Issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018.

At December 31, 2016 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $400 million, $1.2 billion, of which $500 million relates to Fuel Company, and $200 million, respectively, which expire in December 2020. In addition, at December 31, 2016 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2016, the Company had no outstanding borrowings under its credit facilities, had approximately $941 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC-supported letters of credit, and held approximately $208 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. The Company's average short-term borrowings outstanding during 2016 were approximately $857 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2016, the Company's long-term debt portfolio has a weighted average maturity of approximately 20 years and bears an average cost of 5.8%. Substantially all long-term debt bears fixed interest rates or is swapped to fixed.

The Company's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy's note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

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The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016, approximately $79.0 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2016, the Bond Ratio was 5.12.

Financing Activities

During 2016, net cash inflows related to financing activities totaled approximately $560 million, primarily associated with the proceeds from the issuance of long-term debt and short-term borrowings, partially offset by the payment of dividends.

On November 1, 2016, Consolidated SCE&G paid at maturity $100 million related to a nuclear fuel financing which had an imputed interest rate of 0.78%.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of the $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from this sale were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.70% junior subordinated notes at their face value.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $113 million in 2016, $253 million, net, in 2015 and approximately $95 million in 2014.

For additional information, see Note 4 to the consolidated financial statements.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2016, were as follows:

December 31,	2016	2015	2014	2013	2012
	3.38	4.40	3.39	3.22	2.93

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The Company's ratio for 2015 reflects the impact of gains recorded upon the sale of certain subsidiaries. See Note 1 to the consolidated financial statements.

NEW NUCLEAR CONSTRUCTION MATTERS

For a discussion of developments related to new nuclear construction, see Note 2 and Note 10 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

The operations of the Company are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on financial condition, results of operations and cash flows. In addition, the conditions or requirements that will be imposed by regulatory or legislative proposals often cannot be predicted. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, recovery of such expenditures and costs are expected through existing ratemaking provisions.

For the three years ended December 31, 2016, capital expenditures for environmental control equipment at fossil fuel generating stations totaled $39.5 million. During this same period, expenditures were made for the construction and retirement of landfills and ash ponds, net of disposal proceeds, of approximately $32.8 million. In addition, expenditures were made to operate and maintain environmental control equipment at fossil plants of $9.5 million in 2016, $8.7 million in 2015 and $9.1 million in 2014, which are included in other operation and maintenance expense, and expenditures were made to handle waste ash, net of disposal proceeds, of $2.4 million in 2016, $1.3 million in 2015 and $1.6 million in 2014, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2016, 2015 and 2014 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $38.3 million for 2017 and $120 million for the four-year period 2018-2021. These expenditures are included in the Estimated Capital Expenditures table, discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted "major modifications" which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to the Company's electric and gas systems, as well as impacts on employees and customers, the supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow for the protection of assets and the return of systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

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REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC, under Dodd-Frank, concerning recordkeeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCANA and any of its subsidiaries engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and other matters, including accounting; the DOE under the Federal Power Act as to use of emergency authority and coordination of all applicable federal authorizations and related environmental reviews to site an electric transmission facility; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings); the FERC as to issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters; and the DOE under the Federal Power Act as to use of emergency authority.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.
SCE&G and PSNC Energy	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively. The ORS and the NCUC are responsible for enforcement of federal and state pipeline safety requirements in South Carolina (SCE&G) and North Carolina (PSNC Energy), respectively.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system and certain facilities related to generation and distribution are subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

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Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Accounting for Rate Regulated Operations

Regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the criteria of accounting for rate-regulated utilities may no longer be met, and the write off of regulatory assets and liabilities could be required. Such an event could have a material effect on the results of operations, liquidity or financial position of the Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the regulatory assets and liabilities.

Generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write down in those assets could be required. It is not possible to predict whether any write-downs would be necessary and, if they were, the extent to which they would affect results of operations in the period in which they would be recorded. As of December 31, 2016, net investments in fossil/hydro and nuclear generation assets were approximately $2.2 billion and $5.0 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, estimates are recorded for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. The Company's accounts receivable included unbilled revenues of $178.9 million at December 31, 2016 and $129.1 million at December 31, 2015, compared to total revenues of $4.2 billion in 2016 and $4.4 billion in 2015.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

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Under SCE&G's method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates, less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Asset Retirement Obligations

AROs are accrued for legal obligations associated with the retirement of long-lived tangible assets that result from acquisition, construction, development and normal operation in accordance with applicable accounting guidance. These obligations are recognized at present value in the period in which they are incurred, and associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2016, the Company has recorded AROs of $199 million for nuclear plant decommissioning (as discussed above) and AROs of $359 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of precision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $22.9 million recorded in 2016 reflects the use of a 4.68% discount rate derived using a cash flow matching technique, and an assumed 7.50% long-term rate of return on plan assets. The Company believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2016 would have increased the Company's pension cost by $1.6 million and increased the pension obligation by $23.2 million. Further, had the assumed long-term rate of return on assets been 7.25%, the Company's pension cost for 2016 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2016, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.3%, 4.6%, 7.2% and 8.7%, respectively. The 2016 expected long-term rate of return of 7.50% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2017, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.1%, 5.4%, 6.9% and 8.2%, respectively. For 2017, it is anticipated that the long-term expected rate of return will be 7.25%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's and PSNC Energy's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after 2023. As a result, the significance of pension costs and the criticality of the related estimates will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future based on current market conditions and assumptions.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial

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determination of net expense. The Company used a discount rate of 4.78%, derived using a cash flow matching technique, and recorded a net cost for 2016 of $17.3 million. Had the selected discount rate been 4.53% (25 basis points lower than the discount rate referenced above), the expense for 2016 would have been $0.7 million higher and increased the obligation by $8.3 million. Because the plan provisions include "caps" on company per capita costs, and because employees hired after 2010 are responsible for the full cost of retiree medical benefits elected by them, health care cost inflation rate assumptions do not materially impact the net expense recorded.

Uncertain Income Tax Positions

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. See also Note 5 to the consolidated financial statements.

These income tax deductions and credits are considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, such estimated unrecognized tax benefits totaled $350 million ($219 million net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). The estimates of unrecognized tax benefits were computed with consideration as to whether the claims are (or are not) more likely than not to be sustained and with consideration of analyses of cumulative probabilities regarding potential outcomes. Such estimates involve significant management judgment and varying levels of precision. Changes in such estimates are required to be recorded as circumstances change and additional information regarding the claims and potential outcomes becomes available, and these changes could be significant.

However, as these uncertain tax positions primarily involve the timing of recognition of tax deductions rather than permanent tax attributes, the estimates regarding their recognition do not significantly impact the Company's effective tax rate. Further, the permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to the unrecognized tax benefits, have been deferred within regulatory assets. As such, the impacts of these significant accounting estimates, and changes therein, are primarily reflected on the balance sheet rather than in results of operations.

Upon resolution of the uncertainties, the Company will be required to re-pay any tax benefits claimed which are ultimately disallowed, along with interest on those amounts. In certain circumstances, which the Company considers to be remote, penalties for underpayment of income taxes could also be assessed. Such amounts could be significant and adversely affect cash flow and financial condition.

OTHER MATTERS

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. The Company does not engage in significant off-balance sheet financing or similar transactions, although it is party to various operating leases in the normal course of business for land, office space, furniture, vehicles, equipment, rail cars, a purchase power agreement, and airplanes.

Claims and Litigation

For a description of claims and litigation, see Note 10 to the consolidated financial statements.

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Other

As Georgia's regulated provider, SCANA Energy provides service to customers considered to be low-income or that are otherwise unable to obtain natural gas service from other marketers. SCANA Energy provides this service at rates approved by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA's natural gas distribution and gas marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or placed under contract.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provide information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2016	Expected Maturity Date							
Millions of dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	12.5	721.7	11.1	360.2	489.0	4,789.7	6,384.3	7,040.6
Average Fixed Interest Rate (%)	4.21	6.01	4.40	6.33	4.64	5.73	5.70	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	125.0	147.0	142.7
Average Variable Interest Rate (%)	1.63	1.63	1.63	1.63	1.63	1.16	1.23	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	554.4	704.4	4.4	4.4	4.4	128.6	1,400.6	12.3
Average Pay Interest Rate (%)	2.91	2.22	6.17	6.17	6.17	4.57	2.74	—
Average Receive Interest Rate (%)	1.00	1.00	1.63	1.63	1.63	1.08	1.02	—

December 31, 2015	Expected Maturity Date							
Millions of dollars	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	111.5	10.6	719.8	9.1	358.3	4,673.0	5,882.3	6,336.2
Average Fixed Interest Rate (%)	1.16	4.42	6.02	4.73	6.35	5.63	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	129.4	151.4	145.5
Average Variable Interest Rate (%)	1.11	1.11	1.11	1.11	1.11	0.55	0.63	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	654.4	554.4	4.4	4.4	4.4	133.0	1,355.0	(72.1)
Average Pay Interest Rate (%)	2.89	2.91	6.17	6.17	6.17	4.62	3.10	—
Average Receive Interest Rate (%)	0.62	0.62	1.11	1.11	1.11	0.52	0.61	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of long-term debt and interest rate derivatives, see the Liquidity and Capital Resources section in Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes 4 and 6 to the consolidated financial statements.

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Commodity Price Risk

The following table provides information about the Company's financial instruments, which are limited to financial positions of Energy Marketing and PSNC Energy, that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	2017	2018	2019
Futures – Long			
Settlement Price (a)	3.65	3.43	—
Contract Amount (b)	92.6	15.4	—
Fair Value (b)	102.3	16.5	—
Futures - Short			
Settlement Price (a)	3.65	3.43	—
Contract Amount (b)	49.7	8.0	—
Fair Value (b)	51.6	8.3	—
Options - Purchased Call (Long)			
Strike Price (a)	1.95	—	—
Contract Amount (b)	13.7	—	—
Fair Value (b)	2.6	—	—
Swaps - Commodity			
Pay fixed/receive variable (b)	13.9	8.0	1.0
Average pay rate (a)	3.4075	3.4326	2.9667
Average received rate (a)	3.6240	3.2042	3.0954
Fair Value (b)	14.8	7.5	1.1
Pay variable/receive fixed (b)	30.4	11.3	0.8
Average pay rate (a)	3.6234	3.2431	3.1277
Average received rate (a)	3.2387	3.3488	2.9851
Fair Value (b)	27.1	11.7	0.8
Swaps - Basis			
Pay variable/receive variable (b)	1.5	0.8	0.3
Average pay rate (a)	3.7218	3.4697	3.1904
Average received rate (a)	3.6529	3.4218	3.1234
Fair Value (b)	1.5	0.8	0.3

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2016. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Charlotte, North Carolina
February 24, 2017

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SCANA Corporation and Subsidiaries
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2016	2015
Assets		
Utility Plant In Service	$ 13,444	$ 12,883
Accumulated Depreciation and Amortization	(4,446)	(4,307)
Construction Work in Progress	4,845	4,051
Nuclear Fuel, Net of Accumulated Amortization	271	308
Goodwill	210	210
Utility Plant, Net	14,324	13,145
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $138 and $124	276	280
Assets held in trust, net-nuclear decommissioning	123	115
Other investments	76	71
Nonutility Property and Investments, Net	475	466
Current Assets:		
Cash and cash equivalents	208	176
Receivables:		
Customer, net of allowance for uncollectible accounts of $6 and $5	616	505
Income taxes	142	—
Other	127	227
Inventories:		
Fuel	136	164
Materials and supplies	155	148
Prepayments	105	115
Other current assets	17	43
Total Current Assets	1,506	1,378
Deferred Debits and Other Assets:		
Regulatory assets	2,130	1,937
Other	272	220
Total Deferred Debits and Other Assets	2,402	2,157
Total	$ 18,707	$ 17,146

See Notes to Consolidated Financial Statements.

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December 31, (Millions of dollars)	2016	2015
Capitalization and Liabilities		
Common Stock - no par value, 142.9 million shares outstanding for all periods presented	$ 2,390	$ 2,390
Retained Earnings	3,384	3,118
Accumulated Other Comprehensive Loss	(49)	(65)
Total Common Equity	5,725	5,443
Long-Term Debt, Net	6,473	5,882
Total Capitalization	12,198	11,325
Current Liabilities:		
Short-term borrowings	941	531
Current portion of long-term debt	17	116
Accounts payable	404	590
Customer deposits and customer prepayments	168	137
Taxes accrued	201	242
Interest accrued	84	83
Dividends declared	80	76
Derivative financial instruments	35	50
Other	135	127
Total Current Liabilities	2,065	1,952
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	2,159	1,907
Asset retirement obligations	558	520
Pension and postretirement benefits	373	315
Unrecognized tax benefits	219	44
Regulatory liabilities	930	855
Other	205	228
Total Deferred Credits and Other Liabilities	4,444	3,869
Commitments and Contingencies (Note 10)	—	—
Total	$ 18,707	$ 17,146

See Notes to Consolidated Financial Statements.

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SCANA Corporation and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31, (Millions of dollars, except per share amounts)	**2016**	**2015**	**2014**
Operating Revenues:			
Electric	$ 2,614	$ 2,551	$ 2,622
Gas-regulated	788	811	1,028
Gas-nonregulated	825	1,018	1,301
Total Operating Revenues	4,227	4,380	4,951
Operating Expenses:			
Fuel used in electric generation	576	660	793
Purchased power	64	52	81
Gas purchased for resale	1,054	1,287	1,729
Other operation and maintenance	755	715	728
Depreciation and amortization	371	358	384
Other taxes	254	234	229
Total Operating Expenses	3,074	3,306	3,944
Gain on sale of CGT, net of transaction costs	—	234	—
Operating Income	1,153	1,308	1,007
Other Income (Expense):			
Other income	64	75	122
Other expense	(38)	(60)	(64)
Gain on sale of SCI, net of transaction costs	—	107	—
Interest charges, net of allowance for borrowed funds used during construction of $19, $15 and $16	(342)	(318)	(312)
Allowance for equity funds used during construction	29	27	33
Total Other Expense	(287)	(169)	(221)
Income Before Income Tax Expense	866	1,139	786
Income Tax Expense	271	393	248
Net Income	$ 595	$ 746	$ 538
Earnings Per Share of Common Stock	$ 4.16	$ 5.22	$ 3.79
Weighted Average Common Shares Outstanding (millions)	142.9	142.9	141.9
Dividends Declared Per Share of Common Stock	$ 2.30	$ 2.18	$ 2.10

See Notes to Consolidated Financial Statements.

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SCANA Corporation and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (Millions of dollars)	**2016**	**2015**	**2014**
Net Income	$ 595	$ 746	$ 538
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $2, $(7) and $(9)	4	(12)	(14)
Cash flow hedging activities reclassified to interest expense, net of tax of $4, $4 and $4	7	7	7
Cash flow hedging activities reclassified to gas purchased for resale, net of tax of $4, $9 and $(2)	6	15	(4)
Net unrealized gains (losses) on cash flow hedging activities	17	10	(11)
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $-, $- and $(3)	—	—	(5)
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	(1)	—	1
Net deferred costs of employee benefit plans	(1)	—	(4)
Other Comprehensive Income (Loss)	16	10	(15)
Total Comprehensive Income	$ 611	$ 756	$ 523

See Notes to Consolidated Financial Statements.

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SCANA Corporation and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2016	2015	2014
Cash Flows From Operating Activities:			
Net Income	$ 595	$ 746	$ 538
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain on sale of subsidiaries	—	(355)	—
Deferred income taxes, net	242	(31)	235
Depreciation and amortization	389	368	403
Amortization of nuclear fuel	57	46	45
Allowance for equity funds used during construction	(29)	(27)	(33)
Carrying cost recovery	(17)	(12)	(9)
Changes in certain assets and liabilities:			
Receivables	(112)	188	(33)
Income tax receivable	(142)	—	—
Inventories	(43)	(16)	(62)
Prepayments	11	211	(235)
Regulatory assets	(114)	(31)	(138)
Regulatory liabilities	(2)	(1)	(104)
Accounts payable	44	(78)	36
Unrecognized tax benefits	175	31	10
Taxes accrued	(41)	61	(24)
Pension and other postretirement benefits	51	(6)	133
Derivative financial instruments	(9)	(9)	18
Other assets	(44)	(3)	(35)
Other liabilities	81	(23)	(15)
Net Cash Provided From Operating Activities	1,092	1,059	730
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,579)	(1,153)	(1,092)
Proceeds from sale of subsidiaries	—	647	—
Proceeds from investments (including derivative collateral returned)	860	1,117	347
Purchase of investments (including derivative collateral posted)	(788)	(1,018)	(475)
Payments upon interest rate derivative contract settlement	(113)	(263)	(95)
Proceeds from interest rate derivative contract settlement	—	10	—
Net Cash Used For Investing Activities	(1,620)	(660)	(1,315)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	—	14	98
Proceeds from issuance of long-term debt	592	491	294
Repayments of long-term debt	(117)	(166)	(54)
Dividends	(325)	(309)	(294)
Short-term borrowings, net	410	(387)	542
Deferred financing costs	—	(3)	—
Net Cash Provided From (Used For) Financing Activities	560	(360)	586
Net Increase in Cash and Cash Equivalents	32	39	1
Cash and Cash Equivalents, January 1	176	137	136
Cash and Cash Equivalents, December 31	$ 208	$ 176	$ 137
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $19, $15 and $16)	$ 328	$ 306	$ 301
—Income taxes paid	229	184	299
—Income taxes received	166	—	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	109	244	180
Capital leases	15	6	5

See Notes to Consolidated Financial Statements.

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SCANA Corporation and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON EQUITY

	Common Stock				Accumulated Other Comprehensive Income (Loss)			
Millions	Shares	Outstanding Amount	Treasury Amount	Retained Earnings	Gains (Losses) Cash Flow Hedges	Deferred Employee Benefit Plans	Total AOCI	Total
Balance as of January 1, 2014	141	$ 2,289	$ (9)	$ 2,444	$ (52)	$ (8)	$ (60)	$ 4,664
Net Income				538				538
Other Comprehensive Income (Loss)								
Losses arising during the period					(14)	(5)	(19)	(19)
Losses/amortization reclassified from AOCI					3	1	4	4
Total Comprehensive Income (Loss)				538	(11)	(4)	(15)	523
Issuance of Common Stock	2	99	(1)					98
Dividends Declared				(298)				(298)
Balance as of December 31, 2014	143	$ 2,388	(10)	2,684	(63)	(12)	(75)	4,987
Net Income				746				746
Other Comprehensive Income (Loss)								
Losses arising during the period					(12)	—	(12)	(12)
Losses/amortization reclassified from AOCI					22	—	22	22
Total Comprehensive Income				746	10	—	10	756
Issuance of Common Stock	—	14	(2)					12
Dividends Declared				(312)				(312)
Balance as of December 31, 2015	143	$ 2,402	(12)	3,118	(53)	(12)	(65)	5,443
Net Income				595				595
Other Comprehensive Income (Loss)								
Losses arising during the period					4	(1)	3	3
Losses/amortization reclassified from AOCI					13	—	13	13
Total Comprehensive Income (Loss)				595	17	(1)	16	611
Issuance of Common Stock	—	—	—					—
Dividends Declared				(329)				(329)
Balance as of December 31, 2016	143	$ 2,402	$ (12)	$ 3,384	$ (36)	$ (13)	$ (49)	$ 5,725

Dividends declared per share of common stock were $2.30, $2.18 and $2.10 for 2016, 2015 and 2014, respectively.

See Notes to Consolidated Financial Statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina, the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia and conducts other energy-related business.

The accompanying consolidated financial statements reflect the accounts of SCANA, the following wholly-owned subsidiaries, and subsidiaries that formerly were wholly-owned during the periods presented.

Regulated businesses	**Nonregulated businesses**
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	ServiceCare, Inc.
South Carolina Generating Company, Inc.	SCANA Services, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Corporate Security Services, Inc.
	SCANA Communications Holdings, Inc.

SCANA reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance.

Dispositions

In the first quarter of 2015, SCANA sold CGT and SCI. CGT was an interstate natural gas pipeline regulated by FERC that transported natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provided fiber optic communications and other services and built, managed and leased communications towers in several southeastern states, and it was sold to Spirit Communications. These sales resulted in recognition of pre-tax gains totaling approximately $342 million. The pre-tax gain from the sale of CGT is included within Operating Income and the pre-tax gain from the sale of SCI is included within Other Income (Expense) on the consolidated statement of income.

CGT and SCI operated principally in wholesale markets, whereas the Company’s primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment and were included within All Other in Note 12. The sales of CGT and SCI did not represent a strategic shift that had a major effect on operations; therefore, these sales did not meet the criteria for classification as discontinued operations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current presentation, as follows:

Statements of Cash Flows - Non-cash changes in fair value of interest rate swaps were reclassified as an offset to the changes in certain assets and liabilities section within the reconciliations of Net Income to Net Cash Provided From Operating Activities as follows:

	December 31,	
Millions of dollars	**2015**	**2014**
Derivative financial instruments	$ (174)	$ 207
Regulatory assets	179	(234)
Regulatory liabilities	4	(29)
Other assets	(15)	32
Other liabilities	6	24

In addition, due to insignificance, the caption for Losses from equity method investments has been eliminated, and the amounts have been reclassified and included within the caption of Changes in Other assets.

The reclassifications above had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the consolidated statements of cash flows.

Segment of Business Information Disclosure - The Gas Marketing segment includes the information formerly reported in two separate marketing segments. See Note 12 for the required disclosures.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company's regulated subsidiaries calculated AFC using average composite rates of 5.3% for 2016, 6.1% for 2015, and 7.2% for 2014. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. In addition, CGT was sold in the first quarter of 2015 (see Dispositions herein) and excluded from the 2015 calculation of composite weighted average depreciation rates. The composite weighted average depreciation rates for utility plant assets were as follows:

	2016	**2015**	**2014**
SCE&G	2.56 %	2.55 %	2.85 %
GENCO	2.66 %	2.66 %	2.66 %
CGT	—	—	2.11 %
PSNC Energy	2.90 %	2.94 %	2.98 %
Weighted average of above	2.61 %	2.61 %	2.84 %

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SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in Fuel used in electric generation and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2016		2015	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.3 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 634.4 million	—	$620.4 million	—
Construction work in progress	$ 167.7 million	$ 4.2 billion	$214.6 million	$ 3.4 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Unit 1 and the New Units. These amounts totaled $76.2 million at December 31, 2016 and $178.8 million at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2016, and 2015, SCE&G incurred $23.8 million and $16.5 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, SCE&G accrues $17.2 million annually for its portion of the nuclear refueling outages scheduled from the spring of 2014 through the spring of 2020. Refueling outage costs incurred for which SCE&G was responsible totaled $26.8 million for the Fall 2015 outage and $1.8 million in 2016 in preparation for the Spring 2017 outage.

Goodwill

The Company considers certain amounts categorized by FERC as acquisition adjustments to be goodwill. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. Accounting guidance adopted by the Company gives it the option to perform a qualitative assessment of impairment ("step zero"). Based on this qualitative assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with a two-step quantitative assessment. If the quantitative assessment becomes necessary, step one requires estimation of the fair value of the reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Should a write-down be required, such a charge would be treated as an operating expense.

For each period presented, assets with a carrying value of $210 million for PSNC Energy (Gas Distribution segment), net of a writedown of $230 million taken in 2002, were classified as goodwill. The Company utilized the step zero qualitative assessment in its evaluation as of January 1, 2017 and was not required to use the two-step quantitative assessment. In evaluations for preceding periods, the Company's step one assessment utilized the assistance of an independent appraisal in determining its estimate of fair value. In such evaluations, step one indicated no impairment, and no impairment charges were recorded.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Temporary cash investments having original maturities of three months or less at time of purchase are considered to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable.

PSNC Energy utilizes an asset management and supply service agreement with a counterparty for certain natural gas storage facilities. The counterparty held, through an agency relationship, 40% and 46% of PSNC Energy's natural gas inventory at December 31, 2016 and December 31, 2015, respectively, with a carrying value of $9.8 million and $17.7 million, respectively. Under the terms of this agreement, PSNC Energy receives storage asset management fees of which 75% are credited to rate payers. PSNC Energy expects to replace this agreement when it expires on March 31, 2017.

Income Taxes

SCANA files consolidated federal income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities record costs that have been or are expected to be allowed in the ratemaking process in periods different from the periods in which the costs would be charged to expense, or record revenues in periods different from the periods in which the revenues would be recorded, by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations for refunds to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as Receivables - Customer or Customer deposits and customer prepayments, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Premiums, discounts and debt issuance costs are presented within long-term debt and are amortized as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

Revenues and expenses arising from regulated businesses and retail natural gas marketing businesses (including those activities of segments described in Note 12) are presented within Operating Income, and all other activities are presented within Other Income (Expense). Consistent with this presentation, the Company presents the 2015 gain on the sale of CGT within Operating Income and the 2015 gain on the sale of SCI within Other Income (Expense).

Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $178.9 million at December 31, 2016 and $129.1 million at December 31, 2015.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy's PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

Basic earnings per share are computed by dividing net income by the weighted average number of common shares outstanding for the period. When applicable, diluted earnings per share are computed using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method.

New Accounting Matters

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most earlier revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Company expects to adopt this guidance when required in the first quarter of 2018. The guidance permits adoption using a retrospective method, with options to elect certain practical expedients, or recognition of a cumulative effect in the year of initial adoption. The Company has not determined which method of adoption will be employed or what practical expedients may be elected. The Company has not determined the impact this guidance will have on its financial statements. However, the identification of implementation project team members and the analysis of contracts with customers to which the guidance might be applicable, particularly large customer contracts, have begun. In addition, activities of the FASB's Transition Resource Group for Revenue Recognition are being monitored, particularly as they relate to the required treatment under the standard of contributions in aid of construction, alternative revenue programs and the collectibility of revenue of utilities subject to rate regulation.

In May 2015, the FASB issued accounting guidance removing the requirement to categorize within the fair value hierarchy investments for which fair values are estimated using the NAV practical expedient. Disclosures about investments in certain entities that calculate NAV per share are limited under this guidance to those investments for which the entity has elected to estimate the fair value using the NAV practical expedient. The Company elected to adopt this guidance on a retrospective basis. The adoption resulted in the reclassification of fair value related to the pension plan's investment in the common collective trust, joint venture interest, and limited partnership as of December 31, 2015. See Note 8.

In July 2015, the FASB issued accounting guidance intended to simplify the measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. The Company expects to adopt this guidance in the first quarter of 2017 and does not expect it to have a significant impact on the Company's financial statements.

In January 2016, the FASB issued accounting guidance that will change how entities measure certain equity investments and financial liabilities, among other things. The Company expects to adopt this guidance when required in the first quarter of 2018 and has determined adoption of this guidance will not have a significant impact on the Company's financial statements.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over 12 months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily on the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for years beginning in 2019. The Company has not determined what impact this guidance will have on its financial statements. However, the identification of implementation project team members and the initial identification and analysis of leasing and related contracts to which the guidance might be applicable have begun. In addition, the Company has begun evaluating certain third party software tools that may assist with this implementation and ongoing compliance.

In March 2016, the FASB issued accounting guidance changing how companies account for certain aspects of share-based payments to employees. Entities are required to recognize the income tax effects of awards in the income statement when the awards vest or are settled. The Company adopted this guidance in the fourth quarter of 2016 and, based on the nature of its share-based awards practices, the adoption had no impact on the Company's financial statements.

In June 2016, the FASB issued accounting guidance requiring the use of a current expected credit loss impairment model for certain financial instruments. The new model is applicable to trade receivables and most debt instruments, among other financial instruments, and is intended to result in certain impairment losses being recognized earlier than under current guidance. The Company must adopt this guidance beginning in 2020, including interim periods, though the guidance may be adopted in 2019. The Company has not determined when this guidance will be adopted or what impact it will have on the Company's financial statements.

In August 2016, the FASB issued accounting guidance to reduce diversity in cash flow classification related to certain transactions. The Company expects to adopt this guidance when required in the first quarter of 2018 and does not anticipate that its adoption will impact the Company's financial statements.

In October 2016, the FASB issued accounting guidance related to the tax effects of intra-entity asset transfers of assets other than inventory. An entity will be required to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The Company expects to adopt this guidance in the first quarter 2017 and it is not expected to have a material impact on the Company's financial statements.

In November 2016, the FASB issued accounting guidance related to the presentation of restricted cash on the statement of cash flows. The guidance is effective for years beginning in 2018 and the Company expects no impact on its financial statements.

In January 2017, the FASB issued accounting guidance to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test. The same one-step impairment test will be applied to goodwill at all reporting units, even those with zero or negative carrying amounts. The guidance is effective for years beginning in

2020, though early adoption after January 1, 2017 is allowed. The Company has not determined when this guidance will be adopted but does not anticipate that adoption will have a material impact on the Company's financial statements.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments were fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G, ORS, and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million ($.12 per share) in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million ($.06 per share) with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

By order dated April 29, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties to decrease the total fuel cost component of retail electric rates. SCE&G reduced the total fuel cost component of retail electric rates to reflect lower projected fuel costs and to eliminate over-collected balances of approximately $61 million for base fuel and environmental costs over a 12-month period beginning with the first billing cycle of May 2016. SCE&G also began to recover projected DER program costs of approximately $6.9 million beginning with the first billing cycle of May 2016.

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In October 2016, the SCPSC initiated its 2017 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 6, 2017.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G removes from rate base certain deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G's weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $14.0 million and $9.5 million during 2016 and 2015, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these deferred income tax assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2016	First billing cycle of May	$ 37.6 million
2015	First billing cycle of May	$ 32.0 million
2014	First billing cycle of May	$ 15.4 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G's request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider is designed to allow SCE&G to recover projected pension costs, including under-collections, over a 12-month period, beginning with the first billing cycle in May 2016.

In January 2017, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved the filing would allow recovery of $37.0 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric – BLRA

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed ROE. The SCPSC has approved recovery of the following amounts.

Year	Increase	Effective for bills rendered on and after	Amount	Allowed ROE	
2016	2.7%	November 27	$64.4 million	10.50%	*
2015	2.6%	October 30	$64.5 million	11.00%	
2014	2.8%	October 30	$66.2 million	11.00%	

* Applied prospectively for purposes of calculating revised rates under the BLRA on and after January 1, 2016.

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In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time. See also New Nuclear Construction in Note 10.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued.

Gas - SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2016	1.2% Increase	$ 4.1 million
2015	No change	—
2014	0.6% Decrease	$ 2.6 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2016, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Gas - PSNC Energy

PSNC Energy's Rider D rate mechanism allows it to recover from customers all prudently incurred gas costs and certain related uncollectible expenses as well as losses on negotiated gas and transportation sales.

PSNC Energy establishes rates using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

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On October 28, 2016, the NCUC granted PSNC Energy a net annual increase of approximately $19.1 million, or 4.39%, in rates and charges to customers, and set PSNC Energy's authorized ROE at 9.7%. In addition, PSNC Energy was authorized to implement a tracker that provides for biannual rate adjustments to recover the revenue requirement associated with integrity management plant investment and associated costs resulting from prevailing federal standards for pipeline integrity and safety that are not otherwise included in current base rates. The new rates are effective for services rendered on or after November 1, 2016.

In November 2016, in connection with PSNC Energy's 2016 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2016.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, the Company has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2016**	**2015**
Regulatory Assets:		
Accumulated deferred income taxes	$ 316	$ 298
AROs and related funding	425	405
Deferred employee benefit plan costs	342	325
Deferred losses on interest rate derivatives	620	535
Unrecovered plant	117	127
Environmental remediation costs	32	42
DSM Programs	59	61
Pipeline integrity management costs	33	19
Carrying costs on deferred tax assets related to nuclear construction	32	18
Deferred storm damage costs	20	—
Deferred costs related to uncertain tax position	15	—
Other	119	107
Total Regulatory Assets	$ 2,130	$ 1,937
Regulatory Liabilities:		
Asset removal costs	$ 755	$ 732
Deferred gains on interest rate derivatives	151	96
Other	24	27
Total Regulatory Liabilities	$ 930	$ 855

Accumulated deferred income tax liabilities that arise from utility operations that have not been included in customer rates are recorded as a regulatory asset. A substantial portion of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 11 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G or PSNC Energy, and are expected to be recovered over periods of up to approximately 18 years.

DSM Programs represent SCE&G's deferred costs associated with such programs, and such deferred costs are currently being recovered over approximately five years through an approved rate rider.

Pipeline integrity management costs represent costs incurred to comply with regulatory requirements related to natural gas pipelines located near moderate to high density populations. PSNC Energy will recover costs totaling $20.3 million over a five-year period beginning November 2016, and remaining costs of $7.0 million have been deferred pending future approval of rate recovery. SCE&G began amortizing $1.9 million of such costs annually in November 2015.

Carrying costs on deferred tax assets related to nuclear construction are calculated on accumulated deferred income tax assets associated with the New Units which are not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs will be amortized over ten years beginning in approximately 2020.

Deferred storm damage costs represent costs incurred in excess of amounts previously collected through SCE&G's SCPSC-approved storm damage reserve, and for which SCE&G expects to receive future recovery through customer rates.

Deferred costs related to uncertain tax position primarily represent the estimated amounts of domestic production activities deductions foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest expense and other costs arising from this uncertain tax position. SCE&G's current customer rates reflect the availability of domestic production activities deductions. These net deferred costs are expected to be recovered through utility rates following ultimate resolution of the claims. See also Note 5.

Various other regulatory assets are expected to be recovered through rates over periods up to 2047.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's financial statements in the period the write-off would be recorded.

3. COMMON EQUITY

SCANA's articles of incorporation do not limit the dividends that may be paid on its common stock, and the articles of incorporation of each of SCANA's subsidiaries contain no such limitations on their respective common stock. However, SCE&G's bond indenture and PSNC Energy's note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016 and 2015, retained earnings of approximately $79.0 million and $72.4 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

Authorized shares of common stock were 200 million as of December 31, 2016 and 2015.

SCANA issued no common stock during the year ended December 31, 2016. SCANA issued common stock valued at $14.3 million (when issued) during the year ended December 31, 2015, to satisfy the requirements of deferred compensation and dividend reinvestment plans.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

December 31,		2016		2015	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42 %	$ 800	5.42 %
SCANA Senior Notes (unsecured) (a)	2017 - 2034	79	1.63 %	84	1.11 %
SCE&G First Mortgage Bonds (secured)	2018 - 2065	4,840	5.79 %	4,340	5.78 %
GENCO Notes (secured)	2017 - 2024	213	5.93 %	220	5.92 %
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.51 %	122	3.51 %
PSNC Energy Senior Debentures and Notes	2020 - 2046	450	5.53 %	350	5.93 %
Nuclear Fuel Financing	2016	—	— %	100	0.78 %
Other	2017 - 2027	27	2.76 %	18	2.72 %
Total debt		6,531		6,034	
Current maturities of long-term debt		(17)		(116)	
Unamortized discount, net		(1)		—	
Unamortized debt issuance costs		(40)		(36)	
Total long-term debt, net		$ 6,473		$ 5,882	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%).
(b) Includes variable rate debt of $67.8 million at December 31, 2016 (rate of 0.76%) and 2015 (rate of 0.03%) which are hedged by fixed swaps.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5%

first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from this sale were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

The Company's long-term debt maturities will be $17 million in 2017, $726 million in 2018, $15 million in 2019, $365 million in 2020 and $493 million in 2021.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2016, the Bond Ratio was 5.12.

Lines of Credit and Short-Term Borrowings

At December 31, 2016 and 2015, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

	December 31, 2016			
Millions of dollars	**Total**	**SCANA**	**SCE&G**	**PSNC Energy**
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 940.5	$ 64.4	$ 804.3	$ 71.8
Weighted average interest rate		1.43 %	1.04 %	1.07 %
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,056.2	$ 332.6	$ 595.4	$ 128.2

	December 31, 2015			
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 531.4	$ 37.4	$ 420.2	$ 73.8
Weighted average interest rate		1.19 %	0.74 %	0.77 %
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,465.4	$ 359.6	$ 979.6	$ 126.2

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to credit agreements in the amounts and for the terms described above. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	**2016**	**2015**	**2014**
Current taxes:			
Federal	$ 36	$ 382	$ 38
State	13	57	(4)
Total current taxes	49	439	34
Deferred tax (benefit) expense, net:			
Federal	203	(36)	184
State	21	(7)	34
Total deferred taxes	224	(43)	218
Investment tax credits:			
Amortization of amounts deferred-state	—	(1)	(1)
Amortization of amounts deferred-federal	(2)	(2)	(3)
Total investment tax credits	(2)	(3)	(4)
Total income tax expense	$ 271	$ 393	$ 248

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2016	2015	2014
Net income	$ 595	$ 746	$ 538
Income tax expense	271	393	248
Total pre-tax income	$ 866	$ 1,139	$ 786
Income taxes on above at statutory federal income tax rate	$ 303	$ 399	$ 275
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	27	38	24
State investment tax credits (less federal income tax effect)	(5)	(6)	(5)
Allowance for equity funds used during construction	(10)	(9)	(11)
Deductible dividends—401(k) Retirement Savings Plan	(10)	(10)	(10)
Amortization of federal investment tax credits	(2)	(2)	(3)
Section 41 tax credits	—	1	(3)
Section 45 tax credits	(8)	(9)	(9)
Domestic production activities deduction	(23)	(18)	(7)
Realization of basis differences upon sale of subsidiaries	—	7	—
Other differences, net	(1)	2	(3)
Total income tax expense	$ 271	$ 393	$ 248

The tax effects of significant temporary differences comprising net deferred tax liability are as follows:

Millions of dollars	2016	2015
Deferred tax assets:		
Nondeductible accruals	$ 148	$ 135
Asset retirement obligation, including nuclear decommissioning	213	199
Financial instruments	22	35
Unamortized investment tax credits	15	16
Deferred fuel costs	17	8
Other	10	5
Total deferred tax assets	425	398
Deferred tax liabilities:		
Property, plant and equipment	2,159	1,906
Deferred employee benefit plan costs	105	96
Regulatory asset, asset retirement obligation	143	135
Regulatory asset, unrecovered plant	45	49
Demand side management costs	23	23
Prepayments	32	31
Other	77	65
Total deferred tax liabilities	2,584	2,305
Net deferred tax liability	$ 2,159	$ 1,907

The State of North Carolina lowered its corporate income tax rate from 6.9% to 6.0% in 2014, 5.0% in 2015, 4% in 2016 and 3% effective January 1, 2017. In connection with these changes in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The changes in income tax rates did not and are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

The Company files consolidated federal income tax returns, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company's federal returns through 2004, and the Company's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2015 as a result of claims discussed below in Changes in Unrecognized

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Tax Benefits. With few exceptions, the Company is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes in Unrecognized Tax Benefits

Millions of dollars	2016	2015	2014
Unrecognized tax benefits, January 1	$ 49	$ 16	$ 3
Gross increases—uncertain tax positions in prior period	94	33	—
Gross decreases—uncertain tax positions in prior period	—	(2)	—
Gross increases—current period uncertain tax positions	207	2	13
Unrecognized tax benefits, December 31	$ 350	$ 49	$ 16

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models.

The IRS examined the claims in the amended returns, and as the examination progressed without resolution, the Company evaluated and recorded adjustments to unrecognized tax benefits; however, none of these changes materially affected the Company's effective tax rate. In October 2016, the examination of the amended tax returns progressed to the IRS Office of Appeals. In addition, the IRS has begun an examination of SCANA's 2013 through 2015 income tax returns.

These income tax deductions and credits are considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, the Company has recorded an unrecognized tax benefit of $350 million ($219 million, net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). If recognized, $17 million of the tax benefit would affect the Company's effective tax rate (see discussion below regarding deferral of benefits related to 2015 forward). It is reasonably possible that these unrecognized tax benefits may increase by an additional $292 million within the next 12 months as additional expenditures giving rise to pilot model tax benefits are incurred. It is also reasonably possible that these unrecognized tax benefits may decrease by $49 million within the next 12 months if the claims on the amended returns which are currently in appeals are resolved and that resolution were also applied to the 2013 and 2014 returns. No other material changes in the status of the Company's tax positions have occurred through December 31, 2016.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 income tax returns and the expectation of similar claims to be made in determining 2016's taxable income, the Company has recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, and expects that such (net) deferred costs, along with any interest (see below) and other related deferred costs, will be recoverable through customer rates in future years. SCE&G's current customer rates reflect the availability of domestic production activities deductions (see Note 2).

Estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 income tax returns has been deferred as a regulatory asset and is expected to be recoverable through customer rates in future years. See also Note 2. Otherwise, the Company recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. In 2016, the amount recorded for such interest income is $1.8 million and interest expense is $0.9 million. Such amounts were not significant in 2015 or 2014. No amounts have been recorded for tax penalties for any periods presented.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Derivative instruments are recognized either as assets or liabilities in the statement of financial position and are measured at fair value. Changes in the fair value of derivative instruments are recognized either in earnings, as a component of other comprehensive income (loss) or, for regulated operations, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures, and in some cases risk limits, are established to control the level of market, credit, liquidity and operational and administrative risks. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Risk Management Officer and other senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statements of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and NYMEX futures and options. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the under- or over-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SCANA Energy, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

Interest rate swaps may be used to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which swaps designated as cash flow hedges are used to synthetically convert variable rate debt to fixed rate debt, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

Forward starting swap agreements that are designated as cash flow hedges may be used in anticipation of the issuance of debt. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For SCANA and its nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts related to them are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be amortized to interest expense or may be applied as otherwise directed by the SCPSC.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)		
Hedge designation	**Gas Distribution**	**Gas Marketing**	**Total**
As of December 31, 2016			
Commodity	4,510,000	11,947,000	16,457,000
Energy Management (a)	—	67,447,223	67,447,223
Total (a)	4,510,000	79,394,223	83,904,223
As of December 31, 2015			
Commodity	7,530,000	11,842,500	19,372,500
Energy Management (a)	—	38,857,480	38,857,480
Total (a)	7,530,000	50,699,980	58,229,980

(a) Includes amounts related to basis swap contracts totaling 730,721 MMBTU in 2016 and 1,842,048 MMBTU in 2015.

The aggregate notional amounts of the interest rate swaps were as follows:

Millions of dollars	**December 31, 2016**	**December 31, 2015**
Designated as hedging instruments	$ 115.6	$ 120.0
Not designated as hedging instruments	1,285.0	1,235.0

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The following table shows the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the consolidated balance sheet, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Millions of dollars	Fair Values of Derivative Instruments		
	Balance Sheet Location	Asset	Liability
As of December 31, 2016			
Designated as hedging instruments			
Interest rate contracts			
	Derivative financial instruments		$ 4
	Other deferred credits and other liabilities		24
Commodity contracts			
	Prepayments	$ 5	
	Other current assets	1	
Total		$ 6	$ 28
Not designated as hedging instruments			
Interest rate contracts			
	Other deferred debits and other assets	$ 71	
	Derivative financial instruments		$ 27
	Other deferred credits and other liabilities		3
Commodity contracts			
	Other current assets	3	
Energy management contracts			
	Prepayments	6	2
	Other current assets	2	1
	Other deferred debits and other assets	2	
	Derivative financial instruments		4
	Other deferred credits and other liabilities		2
Total		$ 84	$ 39
As of December 31, 2015			
Designated as hedging instruments			
Interest rate contracts			
	Derivative financial instruments		$ 4
	Other deferred credits and other liabilities		28
Commodity contracts			
	Other current assets		1
	Derivative financial instruments		4
Total		—	$ 37
Not designated as hedging instruments			
Interest rate contracts			
	Other current assets	$ 10	
	Other deferred debits and other assets	5	
	Derivative financial instruments		$ 33
	Other deferred credits and other liabilities		22
Commodity contracts			
	Other current assets	1	
Energy management contracts			
	Other current assets	11	2
	Other deferred debits and other assets	3	
	Derivative financial instruments		9
	Other deferred credits and other liabilities		3
Total		$ 30	$ 69

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

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Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

Millions of dollars	Loss Deferred in Regulatory Accounts (Effective Portion)	Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount
Year Ended December 31, 2016			
Interest rate contracts	—	Interest expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)

Millions of dollars	Gain or (Loss) Recognized in OCI, net of tax (Effective Portion)	Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion) Location	Amount
Year Ended December 31, 2016			
Interest rate contracts	$ (1)	Interest expense	$ (7)
Commodity contracts	5	Gas purchased for resale	(6)
Total	$ 4		$ (13)
Year Ended December 31, 2015			
Interest rate contracts	$ (2)	Interest expense	$ (7)
Commodity contracts	(10)	Gas purchased for resale	(15)
Total	$ (12)		$ (22)
Year Ended December 31, 2014			
Interest rate contracts	$ (6)	Interest expense	$ (7)
Commodity contracts	(8)	Gas purchased for resale	4
Total	$ (14)		$ (3)

As of December 31, 2016, the Company expects that during the next 12 months reclassifications from AOCI to earnings arising from cash flow hedges will include approximately $5.4 million as a decrease to gas cost, assuming natural gas markets remain at their current levels, and approximately $7.2 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2016, all of the Company's commodity cash flow hedges settle by their terms before the end of the second quarter of 2019.

As of December 31, 2016, the Company expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.8 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Ineffectiveness on interest rate hedges designated as cash flow hedges was insignificant for all periods presented.

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Derivatives Not Designated as Hedging Instruments

Millions of dollars	Loss Deferred in Regulatory Accounts	Gain (Loss) Reclassified from Deferred Accounts into Income: Location	Amount
Year Ended December 31, 2016			
Interest rate contracts	$ (34)	Interest Expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2016, the Company expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $2.4 million as an increase to interest expense.

Credit Risk Considerations

Certain derivative contracts contain contingent credit features. These features may include (i) material adverse change clauses or payment acceleration clauses that could result in immediate payments or (ii) the posting of letters of credit or termination of the derivative contract before maturity if specific events occur, such as a credit rating downgrade below investment grade or failure to post collateral.

Derivative Contracts with Credit Contingent Features

Millions of dollars	December 31, 2016	December 31, 2015
in Net Liability Position		
Aggregate fair value of derivatives in net liability position	$ 50.3	$ 95.2
Fair value of collateral already posted	29.2	50.4
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	21.1	44.8
in Net Asset Position		
Aggregate fair value of derivatives in net asset position	$ 62.9	$ 7.3
Fair value of collateral already posted	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	62.9	7.3

In addition, for fixed price supply contracts offered to certain of SCANA Energy’s customers, the Company could have called on letters of credit in the amount of $1.5 million related to $9.0 million in commodity derivatives that are in a net asset position at December 31, 2016, compared to letters of credit of $3.0 million related to derivatives of $14.0 million at December 31, 2015, if all the contingent features underlying these instruments had been fully triggered.

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Information related to the offsetting derivative assets follows:

Derivative Assets

Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total
As of December 31, 2016				
Gross Amounts of Recognized Assets	$ 71	$ 9	$ 10	$ 90
Gross Amounts Offset in Statement of Financial Position			(4)	(4)
Net Amounts Presented in Statement of Financial Position	71	9	6	86
Gross Amounts Not Offset - Financial Instruments	(9)			(9)
Gross Amounts Not Offset - Cash Collateral Received				
Net Amount	$ 62	$ 9	$ 6	$ 77
Balance sheet location				
Prepayments				$ 9
Other current assets				5
Other deferred debits and other assets				72
Total				$ 86
As of December 31, 2015				
Gross Amounts of Recognized Assets	$ 15	$ 1	$ 15	$ 31
Gross Amounts Offset in Statement of Financial Position			(1)	(1)
Net Amounts Presented in Statement of Financial Position	15	1	14	30
Gross Amounts Not Offset - Financial Instruments	(8)			(8)
Gross Amounts Not Offset - Cash Collateral Received				
Net Amount	$ 7	$ 1	$ 14	$ 22
Balance sheet location				
Other current assets				$ 22
Other deferred debits and other assets				8
Total				$ 30

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Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities

Millions of dollars	**Interest Rate Contracts**	**Commodity Contracts**	**Energy Management Contracts**	**Total**
As of December 31, 2016				
Gross Amounts of Recognized Liabilities	$ 58		$ 9	$ 67
Gross Amounts Offset in Statement of Financial Position			(3)	(3)
Net Amounts Presented in Statement of Financial Position	58	—	6	64
Gross Amounts Not Offset - Financial Instruments	(9)			(9)
Gross Amounts Not Offset - Cash Collateral Posted	(29)			(29)
Net Amount	$ 20	—	$ 6	$ 26
Balance sheet location				
Derivative financial instruments				$ 35
Other deferred credits and other liabilities				29
Total				$ 64
As of December 31, 2015				
Gross Amounts of Recognized Liabilities	$ 87	$ 5	$ 15	$ 107
Gross Amounts Offset in Statement of Financial Position			(1)	(1)
Net Amounts Presented in Statement of Financial Position	87	5	14	106
Gross Amounts Not Offset - Financial Instruments	(8)			(8)
Gross Amounts Not Offset - Cash Collateral Posted	(36)	(5)	(9)	(50)
Net Amount	$ 43	$ —	$ 5	$ 48
Balance sheet location				
Other current assets				$ 3
Derivative financial instruments				50
Other deferred credits and other liabilities				53
Total				$ 106

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Available for sale securities are valued using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	As of December 31, 2016 Level 1	As of December 31, 2016 Level 2	As of December 31, 2015 Level 1	As of December 31, 2015 Level 2
Assets:				
Available for sale securities	$ 14	—	$ 11	—
Held to maturity securities	—	$ 7	—	—
Interest rate contracts	—	71	—	$ 15
Commodity contracts	8	1	1	—
Energy management contracts	6	4	—	14
Liabilities:				
Interest rate contracts	—	58	—	87
Commodity contracts	—	—	1	4
Energy management contracts	2	10	4	12

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2016 and December 31, 2015 were as follows:

Millions of dollars	As of December 31, 2016 Carrying Amount	As of December 31, 2016 Estimated Fair Value	As of December 31, 2015 Carrying Amount	As of December 31, 2015 Estimated Fair Value
The Company	$6,489.8	$7,183.3	$5,997.6	$6,445.7

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them.

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The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2016**	**2015**	**2016**	**2015**
Benefit obligation, January 1	$855.4	$919.5	$253.6	$268.2
Service cost	20.7	24.1	4.4	5.3
Interest cost	39.4	38.2	12.1	11.4
Plan participants' contributions	—	—	1.7	2.4
Actuarial (gain) loss	45.0	(62.4)	14.0	(21.2)
Benefits paid	(56.2)	(64.0)	(11.1)	(12.5)
Benefit obligation, December 31	$904.3	$855.4	$274.7	$253.6

In 2015, based on an evaluation of the mortality experience of the pension plan, a custom mortality table was adopted for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $21.5 million and $2.4 million, respectively.

The accumulated benefit obligation for pension benefits was $874.3 million at the end of 2016 and $829.3 million at the end of 2015. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	**2015**	**2016**	**2015**
Annual discount rate used to determine benefit obligation	4.22 %	4.68 %	4.30 %	4.78 %
Assumed annual rate of future salary increases for projected benefit obligation	3.00 %	3.00 %	3.00 %	3.00 %

A 6.6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.8 million at December 31, 2016 and by $0.8 million at December 31, 2015. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.7 million at December 31, 2016 and by $0.7 million at December 31, 2015.

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Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Fair value of plan assets	$ 793.6	$ 781.7	—	—
Benefit obligation	904.3	855.4	$ 274.7	$ 253.6
Funded status	$ (110.7)	$ (73.7)	$ (274.7)	$ (253.6)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Current liability	—	—	$ (12.6)	$ (11.9)
Noncurrent liability	$ (110.7)	$ (73.7)	(262.1)	(241.7)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Net actuarial loss	$ 10.4	$ 10.4	$ 2.5	$ 1.7
Prior service cost	0.1	0.2	—	—
Total	$ 10.5	$ 10.6	$ 2.5	$ 1.7

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Net actuarial loss	$ 236.1	$ 219.4	$ 34.7	$ 24.0
Prior service cost	2.5	5.9	—	0.3
Total	$ 238.6	$ 225.3	$ 34.7	$ 24.3

In connection with the joint ownership of Summer Station, pension costs attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $23.4 million and $20.3 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $15.8 million and $13.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

Millions of dollars	Pension Benefits 2016	Pension Benefits 2015
Fair value of plan assets, January 1	$ 781.7	$ 861.8
Actual return (loss) on plan assets	68.1	(16.1)
Benefits paid	(56.2)	(64.0)
Fair value of plan assets, December 31	$ 793.6	$ 781.7

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. SCANA uses a dynamic investment strategy for the management of the pension plan assets. This strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2016 and 2015 and the target allocation for 2017 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2017**	**2016**	**2015**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	32%
Hedge Funds	9%	11%	11%

For 2017, the expected long-term rate of return on assets will be 7.25%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active and passive returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

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Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2016 and 2015, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	**2016**	**2015**
Investments with fair value measure at Level 2:		
Mutual funds	$ 125	$ 125
Short-term investment vehicles	16	14
US Treasury securities	18	22
Corporate debt securities	82	78
Municipals	14	14
Total assets in the fair value hierarchy	255	253
Investments at net asset value:		
Common collective trust	453	413
Joint venture interests	86	83
Limited partnership	—	33
Total investments at fair value	$ 794	$ 782

For all periods presented, assets with fair value measurements classified as Level 1 were insignificant, and there were no assets with fair value measurements classified as Level 3. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2016 or 2015. In addition, in 2015 the fair value of pension plan assets totaling $413 million were previously depicted as mutual funds but have been reclassified as Common collective trust for the current presentation.

Mutual funds held by the plan are open-ended mutual funds registered with the SEC. The price of the mutual funds' shares is based on its NAV, which is determined by dividing the total value of portfolio investments, less any liabilities, by the total number of shares outstanding. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. US Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Common collective trust assets and limited partnerships are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds' net assets at fair value by the units outstanding at each valuation date. Joint venture interests assets are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and not traded on a daily basis. The valuation of such multi-strategy hedge fund of funds is estimated based on the NAV of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may influence their fair value.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

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Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2017	$ 63.1	$ 12.9
2018	65.1	13.7
2019	64.5	14.5
2020	64.7	15.3
2021	67.1	15.9
2022-2026	324.4	86.0

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals at the end of 2023, no significant contributions to the pension plan are expected to be made for the foreseeable future based on current market conditions and assumptions.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2016	2015	2014	2016	2015	2014
Service cost	$ 20.7	$ 24.1	$ 20.0	$ 4.4	$ 5.3	$ 4.6
Interest cost	39.4	38.2	40.4	12.1	11.4	12.0
Expected return on assets	(55.9)	(62.0)	(66.7)	n/a	n/a	n/a
Prior service cost amortization	3.9	4.1	4.1	0.3	0.4	0.3
Amortization of actuarial losses	14.8	13.6	4.8	0.5	2.1	—
Net periodic benefit cost	$ 22.9	$ 18.0	$ 2.6	$ 17.3	$ 19.2	$ 16.9

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2016	2015	2014	2016	2015	2014
Current year actuarial (gain) loss	$ 0.6	$ 2.7	$ 3.1	$ 0.8	$ (1.2)	$ 1.3
Amortization of actuarial losses	(0.6)	(0.4)	(0.2)	—	(0.1)	—
Amortization of prior service cost	(0.1)	(0.1)	(0.2)	—	(0.1)	—
Total recognized in OCI	$ (0.1)	$ 2.2	$ 2.7	$ 0.8	$ (1.4)	$ 1.3

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Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2016	2015	2014	2016	2015	2014
Current year actuarial (gain) loss	$ 29.4	$ 9.2	$ 101.3	$ 11.1	$ (18.0)	$ 19.4
Amortization of actuarial losses	(12.7)	(11.9)	(4.0)	(0.4)	(1.8)	—
Amortization of prior service cost	(3.4)	(3.7)	(3.2)	(0.3)	(0.3)	(0.3)
Total recognized in regulatory assets	$ 13.3	$ (6.4)	$ 94.1	$ 10.4	$ (20.1)	$ 19.1

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2016	2015	2014	2016	2015	2014
Discount rate	4.68 %	4.20 %	5.03 %	4.78 %	4.30 %	5.19 %
Expected return on plan assets	7.50 %	7.50 %	8.00 %	n/a	n/a	n/a
Rate of compensation increase	3.00 %	3.00 %	3.00 %	3.00 %	3.00 %	3.75 %
Health care cost trend rate	n/a	n/a	n/a	7.00 %	7.00 %	7.40 %
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00 %	5.00 %	5.00 %
Year achieved	n/a	n/a	n/a	2021	2020	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 0.6	$ 0.1
Prior service cost	0.1	—
Total	$ 0.7	$ 0.1

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2017 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 13.6	$ 1.2
Prior service cost	1.4	—
Total	$ 15.0	$ 1.2

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCANA sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Contributions are matched 100% up to 6% of an employee's eligible earnings. Such matching contributions totaled $27.5 million in 2016, $26.2 million in 2015 and $25.8 million in 2014. Employee deferrals, matching contributions, and earnings on all contributions are fully vested and non-forfeitable at all times.

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9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2014-2016 performance cycle provides for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 and 2016-2018 awards are based on performance over a single three-year cycle. In the performance cycle for the 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash, and 80% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For each of the 2015-2017 and 2016-2018 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. At the Company's discretion, awards under the 2014-2016 performance cycle were paid in cash in February 2017 totaling $28.0 million. Cash-settled liabilities related to earlier performance cycles totaled approximately $18.4 million in 2016, $20.8 million in 2015 and $11.8 million in 2014.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $25.6 million in 2016, $18.0 million in 2015 and $20.3 million in 2014. Such fair value adjustments also resulted in capitalized compensation costs of $3.3 million in 2016, $2.3 million in 2015 and $3.1 million in 2014. At December 31, 2016, unrecognized compensation cost, which is expected to be recognized over a weighted-average period of 18 months, was $23.4 million.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at SCE&G's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin and up to $2.33 billion resulting from an event of a non-nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of total coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $45.8 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Unit 1 for property damage and outage costs up to $415 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $1.8 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on the Company's results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium in 2008 for the design and construction of the New Units. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Estimated operating costs, including the depreciation of the utility plant costs, are then to be recovered through rates beginning when the construction of each New Unit is completed and placed into service. The BLRA also provides that, in the event of abandonment prior to plant completion, construction work in progress costs incurred, including AFC, and a return on those costs may be recoverable through rates, so long as SCE&G demonstrates by a preponderance of the evidence that its decision to abandon the New Unit(s) was prudent. As of December 31, 2016, SCE&G's investment in the New Units, including related transmission, totaled $4.5 billion, for which the financing costs on $3.8 billion have been reflected in rates under the BLRA. See Note 2 for a description of rate changes which have occurred under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. The Consortium has experienced delays throughout much of the project to date, and forecasted work crew efficiency and productivity metrics have not been met. In response, in November 2012, and again in September 2015 and November 2016 (see discussion below), the SCPSC approved SCE&G's requested updates to the milestone schedule, revised contractual substantial completion dates, and increases in capital and other costs. Some of these increased costs were the result of the schedule delays and were the subject of dispute.

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October 2015 Amendment and WEC's Engagement of Fluor

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor as a subcontracted construction manager.

Among other things, the October 2015 Amendment provided SCE&G and Santee Cooper an irrevocable option to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G's 55% portion being approximately $3.345 billion). This total amount to be paid would be reduced by amounts paid since June 30, 2015. SCE&G, on behalf of itself and as agent for Santee Cooper, executed the fixed price option, subject to SCPSC approval, on July 1, 2016.

The October 2015 Amendment:

(i) resolved by settlement and release most outstanding disputes between SCE&G and the Consortium,

(ii) revised the contractual guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), resulting in escalating liquidated damages that are capped at an aggregate of $338 million per New Unit (SCE&G's 55% portion being approximately $186 million per New Unit),

(iv) provided for payment to the Consortium of a completion bonus of $150 million per New Unit (SCE&G's 55% portion being approximately $83 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provided for development of a revised construction milestone payment schedule,

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project,

(vii) provided for an explicit definition of Change in Law designed to reduce the likelihood of certain future commercial disputes, with the Consortium also acknowledging and agreeing that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19, and

(viii) eliminated the requirement or ability of any party to bring suit regarding disputes before substantial completion of the project.

As part of its responsibility as a subcontracted construction manager, Fluor has reviewed and assisted in the development of an updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within the SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits (see below). However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to achieve forecasted productivity and work force efficiency levels.

November 2016 SCPSC Order

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. See also Note 2.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued.

Construction Milestone Payment Schedule and Related DRB Activity

The October 2015 Amendment established a DRB process for resolving certain commercial claims and disputes. The DRB is comprised of three members chosen by the parties, and amounts in dispute of less than $5 million will be resolved by the DRB without recourse. Amounts in dispute greater than $5 million will be resolved by the DRB for the remainder of the construction of the New Units, with a reserved right to further arbitrate or to litigate such issues at the conclusion of construction.

On December 2, 2016 the DRB issued an order establishing a construction milestone payment schedule (see (v) in October 2015 Amendment above) on which SCE&G and WEC had been unable to agree subsequent to the October 2015 Amendment. The dispute related only to the timing of payments; the total amount to be paid was not in dispute. The DRB order provides that certain subcontractor and other supplier-related costs incurred by the Consortium will be reimbursed by the owners regardless of payment-milestone completion, but that other payments will be made only upon documented achievement of the agreed-upon payment-milestones. Such subcontractor and other supplier-related costs comprised approximately $873 million of the $3.345 billion of fixed option payments that were the subject of the DRB order.

Payment and Performance Obligations and Certain Related Uncertainties

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba, WEC's parent company, reaffirmed its guaranty of WEC's payment obligations. Additionally, the EPC Contract provides the owners the right, exercisable upon certain conditions, to obtain payment and performance bonds from WEC equal to 15% of the highest projected three months billings during the applicable year, and their aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bonds.

In late 2015, Toshiba's credit ratings declined to below investment grade following disclosures regarding its operating and financial performance and near-term liquidity. As a result, pursuant to the above-described terms of the EPC Contract, SCE&G has obtained standby letters of credit in lieu of payment and performance bonds from WEC totaling $45 million (or approximately $25 million for SCE&G's 55% share). These standby letters of credit expire annually in February, and they automatically renew for successive one-year periods until their final expiration date of August 31, 2020, unless the issuer provides a minimum 60-day notice that it will not renew. If the issuer provides notice that it will not renew, SCE&G may draw upon the standby letter of credit prior to its expiration. In the event that WEC would be unable to meet its payment and performance obligations under the EPC Contract, it is anticipated this funding would provide a source of liquidity to assist in an orderly transition. In addition, the EPC Contract provides that upon the request of SCE&G, and at owners' cost, the Consortium must escrow certain intellectual property and software for the owners' benefit to assist in completion of the New Units. An escrow arrangement has been established, and certain intellectual property and software have been deposited. Additional deposits are anticipated.

In December 2016 through February 2017, Toshiba and WEC announced further deterioration in their financial position and liquidity related to write-downs arising from WEC's acquisition of Stone and Webster from CB&I (discussed above). The announcements noted that WEC and Toshiba have determined that significant losses will be incurred under the EPC Contract for the New Units and under a similar engineering, procurement and construction agreement for other units currently being constructed in the United States. This determination has impacted their allocation of the CB&I purchase price, resulting in recognition of a large amount of goodwill which has in turn been determined to be impaired. Preliminary recognition of this impairment loss (in excess of $6 billion) has left Toshiba with negative shareholders' equity and threatened its liquidity. In January 2017, Toshiba's credit ratings were further reduced. In response, Toshiba has indicated its interest in monetizing portions of its business as it attempts to restructure and restore its financial position. Toshiba has also indicated that it will withdraw from the nuclear construction business prospectively and that it will significantly alter its risk management oversight of its nuclear power business. WEC has told the Company that it and Toshiba are committed to completing the New Units. Toshiba has acknowledged its parental guaranty to the project, but it has informed the Company that no specific commitment regarding completion of the New Units has been agreed to by it so far.

Toshiba also announced that it had requested (and successfully received) a one-month extension of the deadline for submitting its securities report to Japanese securities regulators for the quarter ended December 31, 2016 to allow an internal investigation into the adequacy of internal controls relating to the purchase price allocation process for WEC's acquisition of Stone & Webster and concerns that senior management at WEC may have exerted inappropriate pressure in order to advance the purchase price allocation process. As part of the announcement, it was stated that Toshiba's audit committee was concerned that an invalidation of internal controls (or even the possibility thereof) might affect Toshiba's quarterly financial statements, and that two law firms had been separately retained by the audit committee and WEC to assist with this investigation.

Although progress on the project was seen in December 2016 and January 2017, including the placement of the first of Unit 2's two steam generators, significant risks and uncertainties remain concerning WEC's ability to improve work force efficiency and productivity performance and to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project. In particular, there can be no assurance that their creditors will continue to provide support or that other sources of liquidity will emerge or continue to be available. In the event that WEC were to fail to complete the project in breach of its obligations under the EPC Contract, its payment obligations for damages would increase substantially above the amount of the liquidated damages described above, but would still be subject to limitations.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under possible arrangements with other contractors or, were it determined to be prudent, halting the project and leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA.

Also, in response to these developments and in light of the DRB-established construction milestone payment schedule, in February 2017, SCE&G initiated its solicitation for increased levels of standby letters of credit in lieu of payment and performance bonds referred to above. However, it is uncertain whether such additional levels of standby letters of credit will be available at reasonable cost or whether any letters of credit will continue to be renewed by their issuers.

Finally, additional claims by the Consortium or SCE&G involving the project schedule, budget and performance may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues, and SCE&G expects to resolve disputes through those means. SCE&G expects to seek recovery through rates of any project costs that arise through such dispute resolution processes, as well as other project costs identified from time to time; however, any such request would be subject to the provisions of the November 2016 SCPSC order discussed above. There can be no assurance that recovery would be granted.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction is subject to customary closing conditions, including receipt of necessary regulatory approvals. This transaction will not affect the payment obligations between the parties during construction of the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. SCE&G's current projected cost for the additional 5% interest being acquired from Santee Cooper is approximately $850 million.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the IRC to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on current tax law and the contractual guaranteed substantial completion dates (and the recently revised forecasted dates of completion) provided above, both New Units would be operational and would qualify for the nuclear production tax credits; however, any further delays in the schedule or changes in tax law could adversely impact these conclusions. See also the Payment and Performance Obligations and Certain Related Uncertainties discussion above. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan remains under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company is monitoring the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives each state from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. The Company expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual SO_2 emissions and annual and ozone season NO_X emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for SO_2 and NO_X and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. The State of South Carolina has chosen to remain in the CSAPR program, even though recent court rulings exempted the state. This allows the state to remain compliant with regional haze standards. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any costs incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The MATS rule has been the subject of ongoing litigation even while it remains in effect. Rulings on this litigation are not expected to have an impact on SCE&G or GENCO due to plant retirements, conversions, and enhancements. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. The Company expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications to ensure compliance with this rule. Any costs incurred to comply with this rule are expected to be recoverable through rates.

The EPA's final rule for CCR became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities.

SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. The Company does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2016, the federal government has not accepted any spent fuel from Unit 1, and it remains unclear when the repository may become available. SCE&G has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2018 and will cost an additional $10.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2016, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $25.7 million and are included in regulatory assets.

Claims and Litigation

The Company is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on the Company’s results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company is obligated under various operating leases for land, office space, furniture, vehicles, equipment, rail cars, a purchase power agreement, and airplanes. Leases expire at various dates through 2057.

	Rent Expense			Future Minimum Rental Payments					
Millions of dollars	**2016**	**2015**	**2014**	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**
The Company	$ 10.2	$ 11.1	$ 12.3	$ 31	$ 29	$ 28	$ 3	$ 3	$ 23

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2016, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.7 billion.

Asset Retirement Obligations

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2016, SCE&G has recorded AROs of approximately $199 million for nuclear plant decommissioning (see Note 1). In addition, the Company has recorded AROs of approximately $359 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	2016	2015
Beginning balance	$520	$563
Liabilities incurred	—	—
Liabilities settled	(11)	(16)
Accretion expense	23	25
Revisions in estimated cash flows	26	(52)
Ending balance	$558	$520

Revisions in estimated cash flows in 2016 primarily related to changes in projected costs, based on a nuclear decommissioning cost study. Such revisions in 2015 related to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study.

11. AFFILIATED TRANSACTIONS

The Company received cash distributions from equity-method investees of $3.7 million in 2016, $4.0 million in 2015 and $7.8 million in 2014. The Company made investments in equity-method investees of $5.5 million in 2016, $4.1 million in 2015 and $5.7 million in 2014.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. Total purchases from this affiliate were $161.8 million in 2016, $233.2 million in 2015 and $260.3 million in 2014. Total sales to this affiliate were $160.8 million in 2016, $232.0 million in 2015 and $259.0 million in 2014. The net of the total purchases and total sales are recorded in Other expenses on the consolidated statements of income. The Company's payable to this affiliate was $16.1 million at December 31, 2016 and $12.9 million at December 31, 2015. The Company's receivable from this affiliate was $16.0 million at December 31, 2016 and $12.8 million at December 31, 2015.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein. Intersegment sales and transfers of electricity and gas are recorded based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively. Gas Marketing is comprised of the marketing operations of SCANA Energy, which markets natural gas to retail customers in Georgia and to industrial and large commercial customers and municipalities in the Southeast.

All Other includes the parent company, a services company and other nonreportable segments that were insignificant for all periods presented. In addition, All Other includes gains from the sales of CGT and SCI (see Note 1) and their operating results and assets prior to their sale in the first quarter of 2015. CGT and SCI were nonreportable segments during all periods presented. External revenue and intersegment revenue for All Other related to CGT and SCI were not significant during any period presented.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. Gas Marketing operates in a deregulated environment.

Management uses operating income to measure segment profitability for its regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, no allocation is made to segments for interest charges, income tax expense or assets other than utility plant. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Interest income is not reported by segment and is not material. Deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the amounts that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs, and totals not allocated to other segments. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Reportable segments have changed from what was reported as of December 31, 2015 to combine the former Retail Gas Marketing and Energy Marketing segments into a single Gas Marketing segment. This change in reportable segments occurred due to changes in the structure of the Company's internal organization which included the integration of strategic planning and reporting for these business units and the related integration of the chief operating decision maker's assessment of performance and resource allocation. Corresponding amounts in prior periods have been revised to conform to the current presentation.

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Disclosure of Reportable Segments

Millions of dollars	Electric Operations	Gas Distribution	Gas Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2016						
External Revenue	$ 2,614	$ 788	$ 825	—	—	$ 4,227
Intersegment Revenue	5	2	111	$ 414	$ (532)	—
Operating Income	957	148	n/a	—	48	1,153
Interest Expense	17	25	1	—	299	342
Depreciation and Amortization	287	82	2	16	(16)	371
Income Tax Expense	8	32	19	—	212	271
Net Income (Loss)	n/a	n/a	30	(18)	583	595
Segment Assets	11,929	2,892	230	1,124	2,532	18,707
Expenditures for Assets	1,275	276	2	11	15	1,579
Deferred Tax Assets	9	32	11	—	(52)	—
2015						
External Revenue	$ 2,551	$ 810	$ 1,018	$ 5	$ (4)	$ 4,380
Intersegment Revenue	6	2	128	413	(549)	—
Operating Income	876	152	n/a	236	44	1,308
Interest Expense	17	23	1	1	276	318
Depreciation and Amortization	277	77	2	16	(14)	358
Income Tax Expense	9	32	18	1	333	393
Net Income	n/a	n/a	28	185	533	746
Segment Assets	10,883	2,606	201	998	2,458	17,146
Expenditures for Assets	1,087	203	2	15	(154)	1,153
Deferred Tax Assets	5	29	15	—	(49)	—
2014						
External Revenue	$ 2,622	$ 1,012	$ 1,301	$ 37	$ (21)	$ 4,951
Intersegment Revenue	7	2	196	437	(642)	—
Operating Income	768	159	n/a	27	53	1,007
Interest Expense	19	22	1	5	265	312
Depreciation and Amortization	300	72	2	24	(14)	384
Income Tax Expense	7	33	19	12	177	248
Net Income (Loss)	n/a	n/a	31	(6)	513	538
Segment Assets	10,182	2,487	290	1,474	2,385	16,818
Expenditures for Assets	936	200	2	52	(98)	1,092
Deferred Tax Assets	11	29	20	15	(75)	—

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13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2016					
Total operating revenues	$1,172	$ 905	$1,093	$1,057	$4,227
Operating income	331	221	348	253	1,153
Net income	176	105	189	125	595
Earnings per share	1.23	.74	1.32	.87	4.16
2015					
Total operating revenues	$1,389	$ 967	$1,068	$ 956	$4,380
Operating income	586	216	292	214	1,308
Net income	400	99	149	98	746
Earnings per share	2.80	.69	1.04	.69	5.22

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA's internal control system was designed by or under the supervision of SCANA's management, including its CEO and CFO, to provide reasonable assurance to SCANA's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA's management assessed the effectiveness of SCANA's internal control over financial reporting as of December 31, 2016. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA's management believes that, as of December 31, 2016, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on SCANA's internal control over financial reporting. This report follows.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016, of the Company and our report dated February 24, 2017, expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Charlotte, North Carolina
February 24, 2017

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MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Common Stock Information

Price Range (NYSE Composite Listing):

	2016				2015			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 74.94	$ 76.41	$ 75.67	$ 70.35	$ 61.95	$ 57.73	$ 56.26	$ 65.57
Low	$ 67.31	$ 69.04	$ 66.02	$ 59.46	$ 54.84	$ 50.17	$ 47.77	$ 52.03

SCANA common stock trades on the NYSE using the ticker symbol SCG. At February 21, 2017 there were 142,916,917 shares of SCANA common stock outstanding which were held by approximately 25,000 shareholders of record. On February 21, 2017 the closing price of SCANA common stock was $66.96.

Dividends Per Share

SCANA declared quarterly dividends on its common stock of $0.575 per share in 2016 and $0.545 per share in 2015.

For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

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PERFORMANCE GRAPH

The line graph that follows compares the cumulative TSR on our common stock over a five year period, assuming reinvestment of dividends, with the S&P Utilities Index, the S&P 500 Index and a group of peer utility industry issuers. We include the peer group index in the performance graph because we measure our TSR against this peer group index to determine whether certain performance share goals under the Long-Term Equity Compensation Plan have been met. The returns for each issuer in the peer group are weighted according to the respective issuer's stock market capitalization at the beginning of each period.

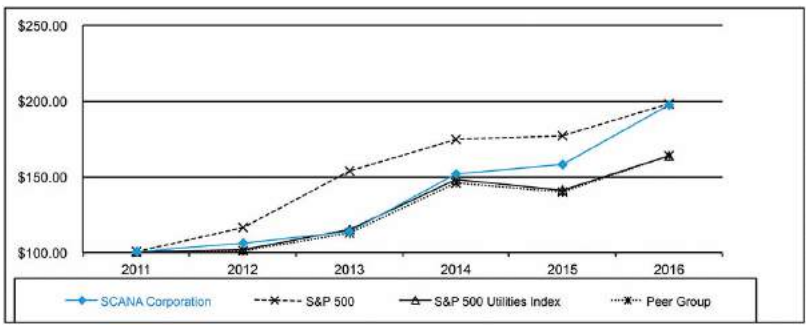
The companies in the 2016 peer group index, with the exception of those few companies that may have merged or otherwise ceased to exist over the five-year period depicted, are listed in the Proxy Statement for the 2017 Annual Meeting under the caption "Compensation Discussion and Analysis — Long-Term Equity Compensation Plan — Performance Criteria for the 2014-2016 Performance Share Awards and Earned and Vested Awards for the 2014-2016 Performance Period" on page 34.

We periodically review and update our peer groups, which are provided to us by management's compensation consultant, and the peer groups may differ from one period to the next because certain companies may no longer meet the compensation consultant's requirements for inclusion (for example a change in revenues may cause a company to no longer qualify for inclusion or a company may merge or otherwise cease to exist). In addition, we may also request that management's compensation consultant include or exclude a particular company if we have information that such a change would be appropriate.

The information set forth in this Performance Graph Section shall not be deemed to be filed with the SEC or incorporated by reference into any of our filings under the Securities Exchange Act of 1934 or the Securities Act of 1933, unless specifically incorporated by reference therein.

Comparison of 5-year Cumulative Total Shareholder Return

December 31, 2011 through December 31, 2016



Five-Year Cumulative Total Shareholder Return
December 31, 2011 - December 31, 2016

	Dec-11	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16
SCANA Corporation	$100.00	$105.64	$113.27	$151.59	$157.88	$197.38
S&P 500 Index	$100.00	$116.00	$153.57	$174.60	$177.01	$198.18
S&P 500 Utilities Index	$100.00	$101.29	$114.67	$147.91	$140.74	$163.66
Index of Peer Companies	$100.00	$100.56	$112.38	$145.64	$139.63	$163.71

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EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all wholly-owned subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	61	Chairman of the Board and Chief Executive Officer President and Chief Operating Officer-SCANA	*-present *-present
Jimmy E. Addison	56	Executive Vice President-SCANA Chief Financial Officer President and Chief Operating Officer-SCANA Energy	*-present *-present 2014-present
Jeffrey B. Archie	59	Senior Vice President and Chief Nuclear Officer-SCE&G Senior Vice President-SCANA	*-present *-present
Sarena D. Burch	59	Senior Vice President-Risk Management and Corporate Compliance Senior Vice President-Fuel Procurement and Asset Management-SCANA, SCE&G and PSNC Energy	2016-present *-2015
Stephen A. Byrne	57	President-Generation and Transmission and Chief Operating Officer-SCE&G Executive Vice President-SCANA	*-present *-present
		Executive Vice President-SCANA	
D. Russell Harris	52	President-Gas Operations-SCE&G President and Chief Operating Officer-PSNC Energy Senior Vice President-Gas Distribution-SCANA Senior Vice President-SCANA	2013-present *-present 2013-present 2012-2013
Kenneth R. Jackson	60	Senior Vice President-Economic Development, Governmental and Regulatory Affairs Vice President-Rates and Regulatory Services	2014-present *-2014
W. Keller Kissam	50	President-Retail Operations-SCE&G Senior Vice President-SCANA	*-present *-present
Ronald T. Lindsay	66	Senior Vice President, General Counsel and Assistant Secretary	*-present
Randal M. Senn	60	Senior Vice President-Administration-SCANA Vice President and Chief Information Officer Chief Information Officer	2016-present 2016 *-2016

* Indicates positions held at least since February 24, 2012.

Director biographical information can be found at pages 9-13 of the Proxy Statement for the Annual Meeting of Shareholders at the forepart of this document.

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SCANA Corporation
220 Operation Way
Cayce, SC 29033
www.scana.com

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SCANA.
POWER FOR LIVING

IMPORTANT ANNUAL MEETING INFORMATION 000004

ENDORSEMENT_LINE______________ SACKPACK______________

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DESIGNATION (IF ANY)
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Admission Ticket

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Electronic Voting Instructions

You can vote by Internet or telephone
24 hours a day, 7 days a week

Instead of mailing your proxy, you may choose one of the two voting methods outlined below to vote your proxy.

VALIDATION DETAILS ARE LOCATED IN THE SHADED BAR BELOW.

Proxies submitted via Internet or telephone must be received by 5:00 p.m., Eastern Daylight Time, on April 26, 2017.

Vote by Internet
- Go to **http://proxy.georgeson.com/**
- Follow the steps outlined on the secure website.

Vote by telephone
- Call toll free 1-877-456-7915 within the USA, US territories & Canada any time on a touch tone telephone. There is **NO CHARGE** to you for the call.
- Follow the instructions provided by the recorded message.

Using a **black ink** pen, mark your votes with an **X** as shown in this example. Please do not write outside the designated areas. X

Annual Meeting Proxy Card 1234 5678 9012 345

▼ **IF YOU HAVE NOT VOTED VIA INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE.** ▼

A Proposals — The Board of Directors recommends a vote FOR all nominees:

1. Election of Class III Director Nominees – Term Expires 2020:

01 - John F.A.V. Cecil 02 - D. Maybank Hagood 03 - Alfredo Trujillo

☐ For All Nominees ☐ Withhold Authority for All Nominees ☐ For All Nominees Except the Following: Write number(s) of nominee(s)

To vote for all nominees, mark the "For All Nominees" box. To withhold voting for all nominees, mark the "Withhold Authority for All Nominees" box. To withhold voting for a particular nominee, mark the "For All Nominees Except the Following" box and enter the number(s) corresponding with the exception(s) in the space provided. Your shares will be voted for the remaining nominees.

The Board of Directors recommends a vote FOR Proposal 2:

	For	Against	Abstain
2. Advisory (non-binding) vote to approve executive compensation.	☐	☐	☐

The Board of Directors recommends a vote of ONE YEAR on Proposal 3:

	1 Year	2 Years	3 Years	Abstain
3. Advisory (non-binding) vote on the frequency of the executive compensation vote.	☐	☐	☐	☐

The Board of Directors recommends a vote FOR Proposals 4 and 5:

	For	Against	Abstain
4. Approval of the appointment of the independent registered public accounting firm.	☐	☐	☐
5. Approval of board-proposed amendments to article 8 of our articles of incorporation to declassify the board of directors and provide for the annual election of all directors.	☐	☐	☐

B Authorized Signatures — THIS SECTION MUST BE COMPLETED FOR YOUR VOTE TO BE COUNTED. DATE AND SIGN BELOW.

Please sign exactly as name(s) appear(s) hereon. Joint owners should each sign. When signing as attorney-in-fact, executor, administrator, corporate officer, trustee, guardian, or custodian, please give full title.

Date (mm/dd/yyyy) — Please print date below.	Signature 1 — Please keep signature within the box.	Signature 2 — Please keep signature within the box.
/ /		

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2017 ANNUAL MEETING ADMISSION TICKET

This **Admission Ticket** or proof of share ownership on the record date of March 1, 2017 is required for admittance to the meeting.

SCANA CORPORATION

April 27, 2017

8:00 A.M. REFRESHMENTS
9:00 A.M. MEETING BEGINS

LEASIDE
100 EAST EXCHANGE PLACE
COLUMBIA, SC 29209

PLEASE NOTE: AUDIO OR VISUAL RECORDING AND RELATED EQUIPMENT IS STRICTLY PROHIBITED WITHOUT THE PRIOR WRITTEN APPROVAL OF THE COMPANY. ONLY ORIGINAL ADMISSION TICKETS WILL BE ACCEPTED AT THE ANNUAL MEETING.

DIRECTIONS TO LEASIDE:

-**From I-77 North** take Exit 9A onto Garners Ferry Road.

-**From I-77 South** take Exit 9A and turn right at traffic light onto Garners Ferry Road.

-East Exchange Place is the first right turn off Garners Ferry Road immediately before Quality Inn & Suites.

-Follow East Exchange Place to Leaside at the end of the street. The parking lot is located in front of the building.

▼ IF YOU HAVE NOT VOTED VIA INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE. ▼

SCANA® POWER FOR LIVING

Proxy — SCANA CORPORATION

2017 Annual Meeting of Shareholders

Proxy Solicited on behalf of the Board of Directors for Annual Meeting — April 27, 2017

The undersigned hereby appoints K.B. Marsh and J.E. Addison, or either of them, as proxies with full power of substitution, to vote all shares of SCANA Corporation common stock in the undersigned's name on the shareholder records of SCANA Corporation, at the Annual Meeting of Shareholders on April 27, 2017, and at any adjournment thereof, as instructed on the reverse hereof, and **in their discretion upon all other matters that may properly be presented for consideration at the meeting.**

Shares will be voted in accordance with your instructions. If no instructions are given, the shares represented by this proxy will be voted "FOR" the election of all nominees as Directors, "FOR" Proposal 2, "ONE YEAR" on Proposal 3, "FOR" Proposal 4, and "FOR" Proposal 5.

(Items to be voted appear on reverse side.)

Meeting Attendance
Mark the box to the right if you plan to attend the Annual Meeting. ☐

C Non-Voting Items

Change of Address — Please print new address below.

Comments — Please print your comments below.

March 24, 2017

TO: All Participants
SCANA Corporation
401(k) Retirement Savings Plan

RE: SCANA Corporation Annual Meeting of Shareholders – April 27, 2017

Enclosed with this letter is your proxy card, which shows the number of shares of SCANA Common Stock in which you have a beneficial interest under the SCANA Corporation 401(k) Retirement Savings Plan ("the Plan"). You have the right to instruct Bank of America, N.A., as Trustee of the Plan, how these shares should be voted at the Annual Meeting of Shareholders. According to the provisions of the Plan, the Trustee is empowered to vote the shares held in the Plan on behalf of participants in accordance with their directions.

In order for your voting instructions to be received by the Trustee in time to be voted at the Annual Meeting of Shareholders on Thursday, April 27, 2017, your proxy must be received by Tuesday, April 25, 2017. **We encourage you to vote your proxy electronically by the internet or telephone.** Internet and telephone voting permit you to vote at your convenience, 24 hours a day, seven days a week. You may also complete, date, sign and return the enclosed card promptly in the envelope provided. This will enable the Trustee to obtain your instructions for voting the shares of SCANA Common Stock in your Plan account. Detailed voting instructions are included on your proxy card. In the absence of your instructions, these shares will be voted by the Trustee in the same proportion as the directed shares in the Plan are voted.

The matters to be acted upon at the meeting are more fully set forth in the Notice of Annual Meeting and Proxy Statement, which is also enclosed.

If you have any questions, you may call the SCANA Corporation Retirement Plans Department at 803-217-9465.

Jimmy E. Addison, Chairman
401(k) Retirement Savings Plan Committee

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SCANA. POWER FOR LIVING

IMPORTANT ANNUAL MEETING INFORMATION 000004

ENDORSEMENT_LINE______________ SACKPACK____________

MR A SAMPLE
DESIGNATION (IF ANY)
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ADD 2
ADD 3
ADD 4
ADD 5
ADD 6

Admission Ticket

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Electronic Voting Instructions

You can vote by Internet or telephone
24 hours a day, 7 days a week

Instead of mailing your proxy, you may choose one of the two voting methods outlined below to vote your proxy.

VALIDATION DETAILS ARE LOCATED IN THE SHADED BAR BELOW.

Proxies submitted via Internet or telephone must be received by 5:00 p.m., Eastern Daylight Time, on April 25, 2017.

Vote by Internet
- Go to **http://proxy.georgeson.com/**
- Follow the steps outlined on the secure website.

Vote by telephone
- Call toll free 1-877-456-7915 within the USA, US territories & Canada any time on a touch tone telephone. There is **NO CHARGE** to you for the call.
- Follow the instructions provided by the recorded message.

Using a **black ink** pen, mark your votes with an **X** as shown in this example. Please do not write outside the designated areas. ☒

Annual Meeting Proxy Card

1234 5678 9012 345

▼ IF YOU HAVE NOT VOTED VIA INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE. ▼

A Proposals — The Board of Directors recommends a vote FOR all nominees:

1. Election of Class III Director Nominees – Term Expires 2020:

01 - John F.A.V. Cecil 02 - D. Maybank Hagood 03 - Alfredo Trujillo

☐ For All Nominees ☐ Withhold Authority for All Nominees ☐ For All Nominees Except the Following: Write number(s) of nominee(s) ____________

To vote for all nominees, mark the "For All Nominees" box. To withhold voting for all nominees, mark the "Withhold Authority for All Nominees" box. To withhold voting for a particular nominee, mark the "For All Nominees Except the Following" box and enter the number(s) corresponding with the exception(s) in the space provided. Your shares will be voted for the remaining nominees.

The Board of Directors recommends a vote FOR Proposal 2:

	For	Against	Abstain
2. Advisory (non-binding) vote to approve executive compensation.	☐	☐	☐

The Board of Directors recommends a vote of ONE YEAR on Proposal 3:

	1 Year	2 Years	3 Years	Abstain
3. Advisory (non-binding) vote on the frequency of the executive compensation vote.	☐	☐	☐	☐

The Board of Directors recommends a vote FOR Proposals 4 and 5:

	For	Against	Abstain
4. Approval of the appointment of the independent registered public accounting firm.	☐	☐	☐
5. Approval of board-proposed amendments to article 8 of our articles of incorporation to declassify the board of directors and provide for the annual election of all directors.	☐	☐	☐

B Authorized Signatures — THIS SECTION MUST BE COMPLETED FOR YOUR VOTE TO BE COUNTED. DATE AND SIGN BELOW.

Please sign exactly as name(s) appear(s) hereon. Joint owners should each sign. When signing as attorney-in-fact, executor, administrator, corporate officer, trustee, guardian, or custodian, please give full title.

Date (mm/dd/yyyy) — Please print date below.	Signature 1 — Please keep signature within the box.	Signature 2 — Please keep signature within the box.
/ /		

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2017 ANNUAL MEETING ADMISSION TICKET

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SCANA CORPORATION

April 27, 2017

8:00 A.M. REFRESHMENTS
9:00 A.M. MEETING BEGINS

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SCANA. POWER FOR LIVING

Proxy — SCANA CORPORATION

2017 Annual Meeting of Shareholders

Proxy Solicited on behalf of the Board of Directors for Annual Meeting — April 27, 2017

The undersigned hereby instructs Bank of America, N.A., as Trustee of the SCANA Corporation 401(k) Retirement Savings Plan (the "Plan"), in accordance with the terms of the Plan, to appoint K.B. Marsh and J.E. Addison, or either of them, as proxies with full power of substitution, to vote all shares of SCANA Corporation common stock in which the undersigned has a beneficial interest, in accordance with the terms of the Plan, at the Annual Meeting of Shareholders on April 27, 2017, and at any adjournment thereof, as instructed on the reverse hereof, and **in their discretion upon all other matters that may properly be presented for consideration at the meeting.**

Shares will be voted in accordance with your instructions. If no instructions are given, the Trustee will instruct the proxies to vote the shares represented by this proxy proportionally to the Plan shares voted.

(Items to be voted appear on reverse side.)

Meeting Attendance
Mark the box to the right if you plan to attend the Annual Meeting. ☐

C Non-Voting Items

Change of Address — Please print new address below.

Comments — Please print your comments below.

As filed with the Securities and Exchange Commission on February 22, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2017

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	**SCANA Corporation** (a South Carolina corporation)	**57-0784499**
1-3375	**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	**57-0248695**

Securities registered pursuant to Section 12(b) of the Act:
SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $9.5 billion at June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $67.01 per share. South Carolina Electric & Gas Company is a wholly-owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 20, 2018
SCANA Corporation	Without Par Value	142,638,371
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Information required by Items 10-13 of Part III of this Form 10-K will be incorporated by reference to SCANA Corporation's definitive proxy statement with respect to its 2018 Annual Meeting of Shareholders, if such definitive proxy statement is filed with the Securities and Exchange Commission on or before April 30, 2018. Due to the pending merger with Dominion Energy, Inc., we may not be required to file a definitive proxy statement with regard to such meeting or may file it after April 30, 2018, in which case we will file an amendment to this Form 10-K on or before April 30, 2018 to include the information that would otherwise be incorporated by reference.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. South Carolina Electric & Gas Company makes no representation as to information relating to SCANA Corporation or its subsidiaries (other than South Carolina Electric & Gas Company and its consolidated affiliates).
South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning the proposed merger with Dominion Energy, recovery of Nuclear Project abandonment costs, key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated capital and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "targets," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements due to the information being of a preliminary nature and subject to further and/or continuing review and adjustment. Other important factors that could cause such material differences include, but are not limited to, the following:

(1) the occurrence of any event, change or other circumstances that could give rise to the failure by SCANA and its subsidiaries (the Company) to consummate the proposed merger with Dominion Energy; (2) the ability of the Company to recover through rates the costs expended on Unit 2 and Unit 3, and a reasonable return on those costs, under the abandonment provisions of the BLRA or through other means; (3) uncertainties relating to the bankruptcy filing by WEC and WECTEC; (4) further changes in tax laws and realization of tax benefits and credits, and the ability or inability to realize credits and deductions, particularly in light of the abandonment of Unit 2 and Unit 3; (5) legislative and regulatory actions, particularly changes related to electric and gas services, rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations including any imposition of fees or taxes on carbon emitting generating facilities, the BLRA, and any actions affecting the abandonment of Unit 2 and Unit 3; (6) current and future litigation, including particularly litigation or government investigations or actions involving or arising from the construction or abandonment of Unit 2 and Unit 3 or arising from the proposed merger with Dominion Energy; (7) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity, and the effect of rating agency actions on the Company's cost of and access to capital and sources of liquidity; (8) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed which may be highly specialized or in short supply, at agreed upon quality and prices, for our construction program, operations and maintenance; (9) the results of efforts to ensure the physical and cyber security of key assets and processes; (10) changes in the economy, especially in areas served by subsidiaries of SCANA; (11) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets; (12) the impact of conservation and demand side management efforts and/or technological advances on customer usage; (13) the loss of electricity sales to distributed generation, such as solar photovoltaic systems or energy storage systems; (14) growth opportunities for SCANA's regulated and other subsidiaries; (15) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries are located and in areas served by SCANA's subsidiaries; (16) changes in SCANA's or its subsidiaries' accounting rules and accounting policies; (17) payment and performance by counterparties and customers as contracted and when due; (18) the results of efforts to license, site, construct and finance facilities, and to receive related rate recovery, for generation and transmission; (19) the results of efforts to operate the Company's electric and gas systems and assets in accordance with acceptable performance standards, including the impact of additional distributed generation; (20) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power; (21) the availability of skilled, licensed and experienced human resources to properly manage, operate, and grow the Company's businesses, particularly in light of uncertainties with respect to legislative and regulatory actions surrounding recovery of Nuclear Project costs and the announced potential merger; (22) labor disputes; (23) performance of SCANA's pension plan assets and the effect(s) of associated discount rates; (24) inflation or deflation; (25) changes in interest rates; (26) compliance with regulations; (27) natural disasters, man-made mishaps and acts of terrorism that directly affect our operations or the regulations governing them; and (28) the other risks and uncertainties described from time to time in the reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
BACT	Best Available Control Technology
Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CGT	Carolina Gas Transmission Corporation
CIAC	Contributions In Aid of Construction
Citibank	Citibank, N.A.
CO_2	Carbon Dioxide
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of WEC and WECTEC
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker (decoupling mechanism)
CWA	Clean Water Act
DECG	Dominion Energy Carolina Gas Transmission LLC
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
District Court	United States District Court for the District of South Carolina
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
Dominion Energy	Dominion Energy, Inc.
DOR	South Carolina Department of Revenue
DOT	United States Department of Transportation
DSM Programs	Electric Demand Side Management Programs
ELG Rule	Federal effluent limitation guidelines for steam electric generating units
EMANI	European Mutual Association for Nuclear Insurance
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008, as amended by the October 2015 Amendment
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
FILOT	Fee in Lieu of Taxes
Fluor	Fluor Corporation

Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
Interim Assessment Agreement	Interim Assessment Agreement dated March 28, 2017, as amended, among SCE&G, Santee Cooper, WEC and WECTEC
IRC	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
Joint Petition	Joint application and petition of SCE&G and Dominion Energy for review and approval of a proposed business combination as set forth in the Merger Agreement and for a prudency determination regarding the abandonment of the Nuclear Project and associated merger benefits and cost recovery plans, filed with the SCPSC on January 12, 2018
kWh	Kilowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LNG	Liquefied Natural Gas
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF	Thousand Cubic Feet
MGP	Manufactured Gas Plant
Merger Agreement	Agreement and Plan of Merger, dated as of January 2, 2018, by and among Dominion Energy, Sedona Corp. (a wholly-owned subsidiary of Dominion Energy) and SCANA
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NASDAQ	The NASDAQ Stock Market, Inc.
NAV	Net Asset Value
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NOL	Net Operating Loss
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
Nuclear Project	Project to construct Unit 2 and Unit 3 under the EPC Contract
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act

PSNC Energy	Public Service Company of North Carolina, Incorporated
Registrants	SCANA and SCE&G
Request	Request for Rate Relief filed by the ORS on September 26, 2017, as amended October 17, 2017
ROE	Return on Equity
RSA	Natural Gas Rate Stabilization Act
RTO/ISO	Regional Transmission Organization/Independent System Operator
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	SCANA Energy Marketing, Inc.
SCANA Services	SCANA Services, Inc.
SCE&G	South Carolina Electric & Gas Company
SCEUC	South Carolina Energy Users Committee
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SLED	South Carolina Law Enforcement Division
SO_2	Sulfur Dioxide
Southern Natural	Southern Natural Gas Company
Spirit Communications	SCTG, LLC and its wholly-owned subsidiary SCTG Communications, Inc.
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Tax Act	An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (previously known as The Tax Cuts and Jobs Act) enacted on December 22, 2017
Toshiba	Toshiba Corporation, parent company of WEC
Toshiba Settlement	Settlement Agreement dated as of July 27, 2017, by and among Toshiba, SCE&G and Santee Cooper
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
Unit 1	Nuclear Unit 1 at Summer Station
Unit 2	Nuclear Unit 2 at Summer Station (abandoned prior to construction completion)
Unit 3	Nuclear Unit 3 at Summer Station (abandoned prior to construction completion)
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
WEC	Westinghouse Electric Company LLC
WECTEC	WECTEC Global Project Services, Inc. (formerly known as Stone & Webster, Inc.), a wholly-owned subsidiary of WEC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

INVESTOR INFORMATION

SCANA's and SCE&G's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at *www.scana.com* (which is not intended as an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC) as soon as reasonably practicable after these reports are filed or furnished.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's Nuclear Project and other matters of interest to investors on SCANA's website. On SCANA's homepage, there is a yellow box containing links to the Nuclear and Other Investor Information sections of the website. The Nuclear section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor-related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the Nuclear Project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear and Other Investor Information yellow box.

CORPORATE STRUCTURE AND SEGMENTS OF BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees as of February 20, 2018 and 2017 of 5,228 and 5,910, respectively. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries, including the subsidiaries described below.

On January 2, 2018, SCANA entered into the Merger Agreement whereby it would become a wholly-owned subsidiary of Dominion Energy. The merger is subject to a variety of closing conditions including the receipt of approvals from several regulators and from SCANA's shareholders. Refer to Exhibit 2.01 in the Exhibit Index for information on where a copy of the Merger Agreement may be obtained. See also Note 10 to the consolidated financial statements for more discussion.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 719,000 customers and the purchase, sale and transportation of natural gas to approximately 368,000 customers (each as of December 31, 2017). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a unit power sales agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 563,000 residential, commercial and industrial customers (as of December 31, 2017). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food and beverage products, health services, automotive, chemicals, motorsports, non-woven textiles and electrical generation and construction.

Nonregulated Businesses

SCANA Energy markets natural gas in the southeast and provides energy-related services. A division of SCANA Energy sells natural gas to approximately 425,000 customers (as of December 31, 2017) in Georgia's deregulated natural gas market.

SCANA Services provides shared administrative and management services to SCANA's other subsidiaries.

For information with respect to major segments of business, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 12 of the consolidated financial statements. All such information is incorporated herein by reference.

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity by customer classification as percentages of electric revenues were as follows:

	Sales	
Customer Classification	**2017**	**2016**
Residential	45%	46%
Commercial	33%	33%
Industrial	18%	17%
Sales for resale	2%	2%
Other	2%	2%
Total	100%	100%

Sales for resale include sales to three municipalities in 2017 and 2016. Other includes short-term system sales which during 2017 included sales to two investor-owned utilities or registered marketers. Short-term system sales during 2016 included sales to four investor-owned utilities or registered marketers.

During 2017 SCE&G experienced a net increase of approximately 10,000 electric customers (growth rate of 1.4%), increasing its total electric customers to approximately 719,000 at year end.

The following projections assume normal weather where applicable. For the period 2017 to 2018, SCE&G projects a retail kWh sales increase of approximately 0.4% and customer growth of 1.5%. For the period 2018-2020, SCE&G projects total territorial kWh sales of electricity to increase 0.3% annually, total retail sales to decrease 0.2% annually, total electric customer base to increase 1.5% annually and territorial peak load (summer, in MW) to increase 1.0% annually. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%; however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a unit power sales agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system extends over a large part of the central, southern and southwestern portions of South Carolina. The system interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Santee Cooper, Georgia Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) were as follows:

	Cost of Fuel Used		
	2017	2016	2015
Per MMBTU:			
Nuclear	$ 0.95	$ 0.98	$ 0.95
Coal	3.31	3.41	3.81
Natural Gas	3.52	3.02	3.26
All Fuels (weighted average)	2.63	2.41	3.01
Per Ton: Coal	82.45	84.62	95.69
Per MCF: Gas	3.57	3.11	3.35

The sources and percentages of total MWh by each category of fuel for the preceding three years and estimates for the next three years follow:

	% of Total MWh Generated					
	Actual			Estimated		
	2015	2016	2017	2018	2019	2020
Coal	39%	37%	39%	38%	29%	30%
Nuclear	20%	25%	20%	20%	23%	20%
Hydro	3%	3%	2%	3%	3%	3%
Natural Gas & Oil	36%	33%	37%	35%	42%	41%
Biomass/Solar	2%	2%	2%	4%	3%	6%
Total	100%	100%	100%	100%	100%	100%

For a listing of the Company's generating facilities, see the Electric Properties section within Item 2. Properties.

In 2017, coal was primarily obtained through long-term contracts with suppliers located in eastern Kentucky, Tennessee, Virginia, and West Virginia. These contracts provide for approximately 2.1 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2019. Spot market purchases may occur when needed or when prices are believed to be favorable. The Company relies on unit trains and, in some cases, trucks for coal deliveries.

SCANA and SCE&G believe that electric operations comply with all applicable regulations relating to the discharge of SO_2 and NO_X. See additional discussion at Environmental Matters in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G, for itself and as agent for Santee Cooper, and WEC are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G supplies enriched products to WEC and WEC supplies nuclear fuel assemblies for Unit 1. WEC is SCE&G's exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Unit 1 through 2033.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to allow for normal operations of its nuclear generating unit.

SCE&G stores spent nuclear fuel in its on-site spent-fuel pool, and has constructed a dry cask storage facility to accommodate the spent fuel output for the life of Unit 1. In addition, Unit 1 has sufficient on-site capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see the Environmental section of Note 10 to the consolidated financial statements.

SCE&G also uses long-term power purchase agreements to ensure that adequate power supply resources are in place to meet load obligations and reserve requirements. As of January 1, 2018, SCE&G had such agreements in place for 325 MW of capacity (expiring at various times through 2020). In addition, SCE&G had the ability to purchase an additional 204 MW of capacity under these agreements. On December 20, 2017, SCE&G entered into an agreement to purchase the Columbia Energy Center, which is the existing 540 MW combined cycle gas generating station to which these capacity contracts relate. Upon the closing of such purchase, these contracts will be moot, and all output of that station will be available for SCE&G's load obligations and reserve requirements. Also, as of December 31, 2017, SCE&G is taking delivery of utility scale solar generated power pursuant to 17 executed power purchase agreements totaling 218 MW-alternating current.

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GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported were as follows:

	SCANA		SCE&G	
Customer Classification	**2017**	**2016**	**2017**	**2016**
Residential	57.1%	57.9%	47.0%	48.3%
Commercial	26.5%	26.4%	27.8%	28.6%
Industrial	11.4%	10.4%	21.6%	19.5%
Transportation Gas	5.0%	5.3%	3.6%	3.6%
Total	100.0%	100.0%	100.0%	100.0%

For the period 2018-2020, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 31.7% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.5%, commercial of 0.9%, and industrial of 84.8%. Projections of total and industrial sales include amounts for new gas-fired electric generating plants that will be served by PSNC Energy.

For the period 2018-2020, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 2.2% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.4%, commercial of 1.0% and industrial of 2.9%.

For the period 2018-2020, each of SCANA's and SCE&G's total regulated natural gas customer base is projected to increase 2.6% annually. During 2017, SCANA recorded a net increase of approximately 24,000 regulated gas customers (growth rate of 2.6%), increasing the number of its regulated gas customers to approximately 931,000. Of this increase, SCE&G recorded a net increase of approximately 10,000 gas customers (growth rate of 2.9%), increasing the number of its total gas customers to approximately 368,000 (as of December 31, 2017).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost and Supply

SCE&G purchases natural gas under contracts with producers and marketers on both a short-term and long-term basis at market based prices. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2019), Transco (expiring at various times through 2084) and DECG (expiring at various times through 2036). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 212,194 MMBTU from Southern Natural, 110,458 MMBTU from Transco and 456,427 MMBTU from DECG. Additional natural gas volumes may be delivered to SCE&G's system as capacity is available through interruptible transportation.

The daily volume of gas that SCANA Energy is entitled to transport under its service agreements (expiring at various times through 2023) on a firm basis is 761,860 MMBTU. Additional natural gas volumes may be delivered as capacity is available through interruptible transportation.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $3.96 per MMBTU during 2017 and $3.46 per MMBTU during 2016.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G has 5,502,600 MMBTU of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 3,433,200 MMBTU of gas were in storage on December 31, 2017. SCE&G supplements its supplies of natural gas with two LNG storage facilities, one of which has liquefaction capability. Approximately 1,624,300 MMBTU (liquefied equivalent) of gas were in storage on December 31, 2017. For a discussion of SCE&G's natural gas storage capacity, see Item 2. Properties.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2031. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 710,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $4.39 per MMBTU during 2017 compared to $3.73 per MMBTU during 2016.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Energy Transmission, Inc., Columbia Gas Transmission, Transco and Enbridge Inc. provide for storage capacity of approximately 13,000,000 MMBTU. Approximately 9,000,000 MMBTU of gas were in storage under these agreements at December 31, 2017. PSNC Energy also maintains LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG which provides 1,300,000 MMBTU (liquefied equivalent) of storage space. Approximately 1,200,000 MMBTU (liquefied equivalent) were in storage under these agreements at December 31, 2017. Approximately 800,000 MMBTU (liquefied equivalent) of gas were in storage at PSNC Energy's LNG storage facility at December 31, 2017. For a discussion of PSNC Energy's LNG storage capacity, see Item 2. Properties.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SCANA Energy markets natural gas and provides energy-related services in the Southeast. In addition, a division of SCANA Energy markets natural gas to greater than 425,000 customers (as of December 31, 2017) in Georgia’s natural gas market. Georgia’s natural gas market includes approximately 1.6 million customers.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements.

REGULATION

Regulatory jurisdictions to which SCANA and its subsidiaries are subject are described in the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018. Were adverse developments to occur with respect to uncertainties highlighted elsewhere, the ability of SCE&G or GENCO to secure renewal of this short-term borrowing authority may be adversely impacted.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	License Expiration
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

* SCE&G operates the Saluda hydroelectric project under an annual license while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 2 to the consolidated financial statements.

Fuel Cost Recovery Procedures

The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions, and the cost of emission allowances used for SO_2, NO_X, mercury and particulates. In addition, the statutory definition of fuel cost allows electric utilities to recover avoided costs under the Public Utility Regulatory Policy Act of 1978, as well as costs incurred as a result of offering DER and net metering programs to its customers. SCE&G may request a formal proceeding concerning its fuel costs at any time.

Purchased gas cost recovery procedures related to the Company's natural gas operations along with related rate proceedings by the SCPSC and NCUC are described in Note 2 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of any new or pending regulations or standards upon existing operations cannot be predicted. For a discussion of how these regulations and standards may impact SCANA and SCE&G (including capital expenditures necessitated thereby), see the Environmental Matters section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements.

OTHER MATTERS

Insurance coverage for Unit 1 is described in Note 10 to the consolidated financial statements.

For a discussion of the impact of competition, see the Overview section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to the Company, and where indicated the risk factors also relate to Consolidated SCE&G.

The completion of the merger is subject to the receipt of consents, approvals and/or findings from governmental entities, which may impose conditions that could have an adverse effect on Dominion Energy or SCANA or could cause either Dominion Energy or SCANA to terminate the merger. The completion of the merger is also subject to there having not been certain substantive changes in certain South Carolina laws that have or would reasonably be expected to have an adverse effect on SCANA or its subsidiaries or changes in law that impose any condition that would reasonably be expected to result in specified changes to the Joint Petition. Additionally, any such changes in certain South Carolina law could affect the considerations which were relied upon by SCANA and/or Dominion Energy prior to the signing of the Merger Agreement.

Dominion Energy and SCANA are not required to complete the merger until after the requisite authorizations, approvals, consents and/or permits are received from the FERC, NRC, SCPSC, NCUC and GPSC. Any of the relevant governmental entities may oppose the merger, fail to approve the merger, fail to make required findings in favor of the merger, or impose certain requirements or obligations as conditions for their consent, approval or findings or in connection with their review. Regulatory approvals of the merger or findings with respect to the merger may not be obtained on a timely basis or at all, and such approvals or findings may include conditions that could have an adverse effect on the Company or Consolidated SCE&G, and/or result in the termination of the merger. The terms of any conditions imposed in order to obtain the requisite regulatory approvals or findings may not be known by the date of the special meeting of SCANA shareholders to vote on the merger proposal. No assurance can be given that the necessary approvals or findings will be obtained or that any required conditions will not have an adverse effect on Dominion Energy following the merger. If SCANA shareholders vote in favor of the merger proposal at the special meeting, Dominion Energy or SCANA may make decisions after the special meeting to waive a condition or approve certain actions required to obtain regulatory approvals or findings without seeking further approval of the SCANA shareholders.

Subject to the terms and conditions set forth in the Merger Agreement, the Merger Agreement requires Dominion Energy to accept conditions from regulators that could adversely impact Dominion Energy after the merger without either of Dominion Energy or SCANA having the right to refuse to close the merger on the basis of those regulatory conditions, except that Dominion Energy is generally not required, and SCANA is generally not permitted without Dominion Energy's prior approval, to take any action or accept any condition that results in a burdensome condition.

In addition, the Merger Agreement provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if, since the date of the Merger Agreement, any governmental entity shall have enacted any order, or there shall have been any change in law (including the BLRA and the other laws governing South Carolina public utilities), which imposes any material change to the terms, conditions or undertakings set forth in the Joint Petition, or any significant changes to the economic value of the Joint Petition, in each case as determined by Dominion Energy in good faith.

The Merger Agreement further provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if there shall have occurred any substantive change in the BLRA or other laws governing South Carolina public utilities which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries. There is currently pending before the South Carolina Senate a bill that would make substantive changes to the BLRA. This bill (H.4375) has passed the South Carolina House of Representatives. If this bill becomes law, Dominion Energy would not be obligated to complete the merger if it is determined that the bill has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries.

Certain lawsuits and regulatory actions have been filed against SCANA and SCE&G in connection with the abandonment of the Nuclear Project. If the relief requested in these matters (including a request for declaratory judgment that the BLRA is unconstitutional) is granted, Dominion Energy might not be obligated to complete the merger.

No assurance can be given that these risks will not materialize and either adversely impact Dominion Energy after the completion of the merger or, if such conditions rise to the thresholds discussed above, some of which, as described above, are in the subjective determination of Dominion Energy acting in good faith, or if the required authorizations, approvals, consents and/or permits are not obtained or received, result in the termination of the merger and adversely impact the results of operations, cash flows and financial conditions of the Company and Consolidated SCE&G.

Failure to complete the merger could negatively impact the stock price and the future business and financial results of SCANA.

If the merger is not completed, the ongoing business of the Company and Consolidated SCE&G may be adversely affected and the Company and Consolidated SCE&G could be subject to several risks, including the following:

- the price of SCANA common stock may decline to the extent that the current market price reflects an expectation by the market that the merger will be completed;
- obligations to pay certain costs relating to the merger, such as legal, accounting, financial advisory, filing, printing and mailing fees;
- the disruption of the Company's and Consolidated SCE&G's ongoing business or inconsistencies in its services, standards, controls, procedures and policies due to management's focus on the merger, any of which could adversely affect the ability of the Company and Consolidated SCE&G to maintain relationships with customers, regulators, vendors and employees, or could otherwise adversely affect the business and financial results of the Company or Consolidated SCE&G, without realizing any of the benefits of having the merger completed;
- the potential negative impact on the Company and Consolidated SCE&G ultimately resolving the rate and regulatory issues, including pending investigations and legal challenges, relating to the abandonment of the Nuclear Project in a manner satisfactory to SCANA on account of SCANA working with Dominion Energy to pursue the resolution of these issues as contemplated by the Merger Agreement rather than pursuing its regulatory and legal options for resolving these issues independently of considerations and obligations related to the merger; and
- the loss of other opportunities that could be beneficial to the Company and Consolidated SCE&G that could have been pursued during the pendency of the merger, without realizing any of the benefits of having the merger completed.

In addition to the above risks, SCANA may be required, under certain circumstances, to pay to Dominion Energy a termination fee of $240 million.

If the merger is not completed, no assurance can be given that these risks will not materialize and will not materially affect SCANA's business, financial results and stock price.

The Merger Agreement contains provisions that limit SCANA's ability to pursue alternatives to the merger, which could discourage a potential competing acquirer of SCANA or could result in any competing proposal being at a lower price than it might otherwise be.

The Merger Agreement contains provisions that, subject to certain exceptions, restrict SCANA's ability to initiate, solicit, knowingly encourage, facilitate or discuss competing third-party proposals to acquire all or a significant part of SCANA, or provide information to a third party that could reasonably be expected to lead to such a proposal. In addition, Dominion Energy generally has an opportunity to offer to modify the terms of the merger in response to any superior acquisition proposal that may be made before the SCANA board of directors is permitted to withdraw or qualify its recommendation. In some circumstances on termination of the Merger Agreement, SCANA may be required to pay to Dominion Energy a termination fee of $240 million.

These provisions, which the SCANA board regards as customary for transactions of this type, could discourage a potential competing acquirer that might have an interest in acquiring all or a significant part of SCANA from considering or proposing that acquisition, even if it were prepared to pay consideration with a higher per share cash or market value than the merger consideration, or might result in a potential competing acquirer proposing to pay a lower price than it might otherwise have proposed to pay because of the added expense of the termination fee that may become payable by SCANA in certain circumstances.

The pendency of the merger could adversely affect the business and operations of SCANA.

In connection with the pending merger, some current or prospective customers or vendors of SCANA's utilities may delay or defer decisions regarding their existing or proposed relationships with those utilities, which could negatively impact the operation, revenues, earnings, cash flows and expenses of the Company and Consolidated SCE&G, regardless of whether the merger is completed. Similarly, current and prospective employees of SCANA and its utilities may experience uncertainty about their future roles following the merger, which may adversely affect the ability of SCANA and its utilities to attract and retain key personnel during the pendency of the merger. In addition, due to operating covenants in the Merger Agreement, during the pendency of the merger, SCANA and its utilities may be unable to pursue strategic transactions, undertake significant capital projects, undertake certain significant financing or other specified transactions or pursue actions that are not in the ordinary course of business, even if such actions would prove beneficial.

Following the merger, Dominion Energy may be unable to successfully integrate the Company's and Consolidated SCE&G's businesses.

Dominion Energy and SCANA currently operate as independent public companies. After the merger, Dominion Energy will be required to devote significant management attention and resources to integrating the Company's and Consolidated SCE&G's business. Potential difficulties Dominion Energy may encounter in the integration process include the following:

- the complexities associated with integrating SCANA and its utility businesses, while at the same time continuing to provide consistent, high quality services;
- the complexities of integrating a company with different core services, markets and customers;
- the inability to attract and retain key employees;
- potential unknown liabilities and unforeseen increased expenses, delays or regulatory conditions associated with the merger;
- difficulties in managing political and regulatory conditions related to SCANA's utility business after the merger;
- the cost recovery plan includes a moratorium on filing requests for adjustments in SCANA's base electric rates until 2021 if the merger is approved by the SCPSC, which would limit Dominion Energy's ability to recover increases in non-fuel related costs of electric operations for SCE&G's customers; and
- performance shortfalls as a result of the diversion of Dominion Energy management's attention caused by completing the merger and integrating SCANA's utility businesses.

For these reasons, you should be aware that it is possible that the integration process following the merger could result in the distraction of Dominion Energy's management, the disruption of Dominion Energy's ongoing business or inconsistencies in its services, standards, controls, procedures and policies, any of which could adversely affect the ability of Dominion Energy to maintain or establish relationships with current and prospective customers, vendors and employees or could otherwise adversely affect the business and financial results of Dominion Energy.

Dominion Energy, the Company and Consolidated SCE&G may be adversely affected by negative publicity related to the merger and in connection with other related matters, including the abandonment of the Nuclear Project.

From time to time, political and public sentiment in connection with the merger and in connection with other matters, including the abandonment of the Nuclear Project, may result in a significant amount of adverse press coverage and other adverse public statements affecting Dominion Energy and the Company and Consolidated SCE&G. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceedings, as well as responding to and addressing adverse press coverage and other adverse public statements, can divert the time and effort of senior management from the management of Dominion Energy's, the Company's and Consolidated SCE&G's respective businesses.

Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of Dominion Energy, the Company and Consolidated SCE&G, on the morale and performance of their employees and on their relationships with their respective regulators, customers and commercial counterparties. It may also have a negative impact on their ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have an adverse effect on Dominion Energy's, the Company's and Consolidated SCE&G's respective business, financial condition, results of operations and prospects.

Pending litigation against SCANA and Dominion Energy could result in an injunction preventing the completion of the merger or may adversely affect the combined company's business, financial condition or results of operations following the merger.

Following the announcement of the merger, three lawsuits were filed asserting claims relating to the merger. First, an existing derivative lawsuit was amended to assert direct claims of a putative class of SCANA shareholders in the Court of Common Pleas of the County of Richland, South Carolina against the members of the SCANA board of directors, Dominion Energy and Sedona Corp., alleging breaches of various fiduciary duties by the members of the SCANA board of directors in connection with the merger and alleging that Dominion Energy and Sedona Corp. aided and abetted such alleged breaches.

Second, two putative class actions on behalf of SCANA shareholders have been filed in the Court of Common Pleas of the Counties of Lexington and Richland, South Carolina, respectively, against SCANA, the members of the SCANA board of directors, Dominion Energy and Sedona Corp., alleging breaches of various fiduciary duties by the members of the SCANA board of directors in connection with the merger and alleging that SCANA, Dominion Energy and Sedona Corp. aided and abetted such alleged breaches. Among other remedies, the plaintiffs in each case seek to enjoin the merger and rescind the Merger Agreement. In addition, the second and third lawsuits seek in the alternative, should the merger be completed, an award of unspecified monetary damages.

While the defendants believe that dismissal is warranted, the outcome of any such litigation is inherently uncertain. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger closes may adversely affect the combined company's business, financial condition or results of operation.

There is uncertainty as to whether the Company and Consolidated SCE&G will be able to recover costs expended for the Nuclear Project, and a reasonable return on those costs, under the abandonment provisions of the BLRA or through other means. As of December 31, 2017, the Company and Consolidated SCE&G have recognized a significant estimated impairment loss with respect to such investment and related costs. In the event the Company and Consolidated SCE&G were to determine that all or an additional portion of their remaining unrecovered Nuclear Project costs are to be disallowed and that significant additional impairment losses must be recognized, further material adverse impacts on their results of operations, cash flows and financial condition would occur.

During the term of the Interim Assessment Agreement, SCE&G and Santee Cooper evaluated the various elements of the Nuclear Project, including forecasted costs and completion dates, while construction continued, and SCE&G and Santee Cooper continued to make payments for such work. Based on this evaluation, and in light of Santee Cooper's decision to suspend construction, on July 31, 2017, the Company determined to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means. On July 31, 2017, SCE&G gave WEC a five-day notice of termination of the Interim Assessment Agreement, and notified WEC of its determination to stop construction of Unit 2 and Unit 3.

On August 1, 2017, SCE&G senior management provided an allowable ex parte briefing to the SCPSC regarding the Nuclear Project and this decision, and SCE&G also filed a petition with the SCPSC which included its plan of abandonment and certain proposed actions which would mitigate related customer rate increases, including a proposal to return to customers the net value of the proceeds received by SCE&G under or arising from the Toshiba Settlement.

The BLRA provides that, in the event of abandonment prior to plant completion, costs incurred, including AFC, and a return on those costs may be recoverable through rates, if the SCPSC determines that the decision to abandon the Nuclear Project was prudent. Through its August 1, 2017 petition, SCE&G had sought recovery of such costs expended on the construction of the project, including certain costs incurred subsequent to SCE&G's last revised rates update, and a reasonable return on those costs, and certain other costs under the abandonment provisions of the BLRA. Subsequently, SCE&G's management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow for adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew its August 1, 2017 petition from the SCPSC on August 15, 2017.

In August 2017, special committees of the South Carolina General Assembly, both in the House of Representatives and in the Senate, began conducting public hearings regarding the decision to abandon the Nuclear Project. Members of SCE&G's senior management, along with representatives from Santee Cooper, the ORS and other interested parties, testified before these committees. Several legislative proposals adverse to the Company and Consolidated SCE&G resulted from the work of these committees and are being considered by the General Assembly in 2018. In January 2018, these committees reconvened for the purpose of considering the effects of the proposed merger. On January 31, 2018, the House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law, the precise impact of any change in the law, or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

In September 2017, the Company was served with a subpoena issued by the United States Attorney's Office for the District of South Carolina seeking documents relating to the Nuclear Project. The subpoena requires the Company to produce a broad range of documents related to the project. Also in September 2017, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. In October 2017, the staff of the SEC's Division of Enforcement also issued a subpoena for documents related to an investigation they are conducting related to the Nuclear Project. The Company and Consolidated SCE&G intend to fully cooperate with these investigations. No assurance can be given as to the timing or outcome of these matters.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections. SCE&G estimates that revised rates collections currently total approximately $445 million annually, and the amounts accumulated as of December 31, 2017 total approximately $1.9 billion.

On September 27, 2017, the scheduled payments under the Toshiba Settlement, exclusive of the payment due in October 2017, were purchased by Citibank for a one-time upfront payment of $1.847 billion (approximately $1.016 billion for SCE&G's 55% share), including amounts related to certain liens that SCE&G was contesting but for which SCE&G may ultimately have been liable. The initial payment was then received from Toshiba on October 2, 2017, as scheduled, in the amount of $150 million ($82.5 million for SCE&G's 55% share). A regulatory liability has been recorded on the consolidated balance sheets to reflect the amount related to the Toshiba Settlement that will be utilized to benefit SCE&G's customers in a manner to be determined by the SCPSC. While this determination is pending, SCE&G has utilized portions of the proceeds to repay maturing commercial paper balances, which short-term borrowings had been incurred primarily for the construction of Unit 2 and Unit 3 prior to the decision to stop their construction. On October 17, 2017, the ORS filed a motion with the SCPSC to amend its earlier Request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. It is possible that the outcome of regulatory or legal proceedings could result in requiring SCE&G's share of these proceeds to be placed in escrow pending their final disposition, or could require these proceeds to be refunded to customers in the near-term or otherwise make these funds unavailable to SCE&G. If any of these circumstances were to arise, it is anticipated that SCE&G would reissue commercial paper or draw on its credit facilities to fund such requirement. However, such sources may not be available. Any such requirement would significantly harm the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition. In addition, the purchase agreement with Citibank provides that SCE&G and Santee Cooper (each according to its pro rata share) would indemnify Citibank for its losses arising from misrepresentations or covenant defaults under the purchase agreement.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. Parties who filed to intervene in the matter or who filed a letter in support of the request by the ORS include the Governor, the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, the SCEUC, certain large industrial customers, and several environmental groups. After conducting a hearing to consider SCE&G's motion, the SCPSC denied the motion on December 20, 2017 and ordered that a hearing be scheduled to consider the Request. The hearing has not yet been scheduled. SCE&G intends to continue vigorously contesting the Request, but cannot give any assurance as to the timing or outcome of this matter. Any adverse action by the SCPSC, such as that sought by the ORS in the Request, could have a material adverse impact on the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

In the third quarter of 2017, SCE&G recorded a pre-tax impairment loss of $210 million related to unrecovered nuclear project costs. In the fourth quarter of 2017, SCE&G recorded an additional pre-tax impairment loss of $908 million related to such unrecovered costs and other related costs. See Note 10 to the consolidated financial statements. These impairment losses have had the effect of increasing the Company's and Consolidated SCE&G's debt to total capitalization. If the SCPSC were to rule in favor of the ORS in response to the Request that SCE&G suspend collections from customers of amounts previously authorized under the BLRA, or were other actions of the SCPSC or others taken in order to significantly restrict SCE&G's access to revenues or impose additional adverse refund obligations on SCE&G, the Company's and Consolidated SCE&G's assessments regarding the recoverability of all or a portion of the remaining balance of unrecovered Nuclear Project costs would be adversely impacted. Also, the recognition of significant additional impairment losses with respect to unrecovered Nuclear Project costs could further increase the Company's and Consolidated SCE&G's debt to total capitalization to a level which may limit their ability to borrow under their commercial paper programs or under their credit facilities and also could constitute a default under these credit facilities. Borrowing costs for long-term debt issuances and access to capital markets could also be negatively impacted.

The ability of SCE&G to recover its costs related to the construction and subsequent abandonment of the Nuclear Project, and a reasonable return on them, through rates will be subject to review and approval by the SCPSC. An application under the abandonment provisions of the BLRA, and the regulatory process contemplated thereby, have never been pursued or legally challenged. As a result, and in light of the contentious nature of the ongoing reviews by and related activities of the South Carolina House Utility Ratepayer Protection Committee, the South Carolina Senate's V.C. Summer Nuclear Project Review Committee and others, and given pending legislation, it is uncertain whether SCE&G will be able to successfully recover the costs of the abandoned units, and a reasonable return on them. Under the BLRA, the SCPSC must consider and rule on a petition within six months. Even so, and although expedited action has been requested by SCE&G, it is unclear when the SCPSC will consider the Joint Petition. In any case, anticipated appeals of any ruling by the SCPSC could be protracted. Further, should the regulatory construct in South Carolina change in such a manner that recovery is sought through other legal proceedings or through regulatory proceedings outside the provisions of the BLRA, such as in a general rate case, other uncertainties may arise, such as those highlighted with respect to the Merger Agreement.

Further downgrades in the credit ratings of SCANA or any of SCANA's subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies currently rate SCE&G's senior secured debt and the senior unsecured debt of PSNC Energy as investment grade. One rating agency currently rates SCANA's senior unsecured debt as investment grade, and two rating agencies rate SCANA's senior unsecured debt as below investment grade. In addition, rating agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements.

In the first quarter of 2017, the rating agencies placed SCANA and SCE&G's credit ratings on negative outlook or watch status due to adverse developments relating to the WEC bankruptcy. In the third quarter of 2017, two agencies lowered their ratings for SCANA and its rated subsidiaries, citing a decline in the regulatory environment as a principal reason for the downgrades, and both agencies maintained their negative outlook or watch status. On January 3, 2018, after SCANA announced a proposed merger with Dominion Energy, each of the three agencies affirmed or reported no change to their respective credit ratings, and one agency revised its rating outlook for SCANA and its rated operating companies from negative to evolving. However, on January 31, 2018, the South Carolina House of Representatives overwhelmingly approved a bill (H. 4375) that, if enacted, would temporarily repeal rates SCE&G collects under the BLRA. As a result, on February 5, 2018, one agency downgraded its ratings for SCANA and SCE&G, and attributed the downgrade to the action taken by the House of Representatives and the politically charged environment that is expected to weigh heavily on any decisions by the SCPSC related to SCE&G's electric rates. All of the ratings for SCANA, SCE&G and PSNC Energy are either under review for possible downgrade or have a negative or evolving outlook.

Any actions taken by or anticipated to be taken by regulators or legislators that are viewed as adverse, including a change to the BLRA or a requirement that SCE&G make credits to future bills or refunds to customers above such amounts as are included in the Merger Agreement or any requirement that SCE&G make such credits or refunds in the absence of the merger being consummated, or deterioration of our rated companies' commonly monitored financial credit metrics and additional adverse developments with respect to the Nuclear Project, could further negatively affect their debt ratings. If these rating agencies were to further lower any of these ratings, borrowing costs on new issuances of long-term debt and commercial paper would increase, which could adversely impact financial results or limit or eliminate refinancing opportunities, and the potential pool of investors and funding sources could decrease. Any further lowering of these ratings could also trigger higher interest costs as well as more stringent collateral requirements on interest rate and commodity hedges and under gas supply agreements and a reduction in the availability of suppliers.

The Company and Consolidated SCE&G are defendants in numerous legal proceedings and the subject of ongoing governmental investigations, examinations and other inquiries stemming from the decision to abandon the Nuclear Project. The outcome of each of these matters is uncertain, and any resolution adverse to the Company and Consolidated SCE&G could adversely affect results of operations, cash flows and financial condition.

Following the Company's decision to abandon construction of Unit 2 and Unit 3, putative derivative and class action lawsuits seeking have been filed in multiple state circuit courts and federal district court on behalf of customers, shareholders and SCANA (in the case of the derivative shareholder actions), against SCANA, SCE&G, or both, and in certain cases some of their officers and/or directors. The plaintiffs allege various causes of action, including but not limited to waste, breach of fiduciary duty, negligence, unfair trade practices, unjust enrichment, conspiracy, fraud, constructive fraud, misrepresentation and negligent misrepresentation, promissory estoppel, constructive trust, and money had and received, among other causes of action. Plaintiffs generally seek compensatory, consequential and statutory treble damages and such further relief as the court deems just and proper. In addition, certain plaintiffs seek a declaration that SCE&G may not charge its customers to reimburse itself for past and continuing costs of the Nuclear Project. Certain plaintiffs also seek to freeze or appoint a receiver for certain of SCE&G's assets, namely all money SCE&G has received under the Toshiba payment guaranty and related settlement agreement for the Nuclear Project.

In addition, purported class action lawsuits have been filed on behalf of investors in federal court against SCANA and certain of its current and former executive officers and directors. The plaintiffs allege, among other things, that defendants violated Section 10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and two suits allege violations of the Racketeer Influenced and Corrupt Organizations Act. In one suit, the plaintiff alleges that director defendants violated Section 14(a) of the Exchange Act and SEC Rule 14a-9 by allowing or causing misleading proxy statements to be issued. The plaintiffs in each of these suits seek compensatory and consequential damages and such further relief as the court deems proper.

A complaint has been filed by Fairfield County against SCE&G making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of the implied duty of good faith and fair dealing, and unfair trade practices related to SCE&G's termination of the FILOT agreement. Plaintiff seeks injunctive relief to prevent SCE&G from terminating the FILOT agreement; actual and consequential damages; treble damages; punitive damages; and attorneys' fees.

The Company has also been served with subpoenas issued by the United States Attorney's Office for the District of South Carolina and the staff of the SEC's Division of Enforcement seeking documents relating to the Nuclear Project. In addition, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee have requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. The Company and Consolidated SCE&G intend to fully cooperate with any such investigations. Also in connection with the abandonment of the Nuclear Project, various state or local governmental authorities have challenged or may attempt to challenge, reverse or revoke one or more previously-approved tax or economic development incentives, benefits or exemptions, including use tax exemptions, and are attempting to apply such action retroactively.

The Company and Consolidated SCE&G cannot predict the outcome of these matters or other claims, allegations or assessments which may arise, and it is possible that adverse outcomes from some of these matters would not be covered by insurance. A resolution adverse to the Company and Consolidated SCE&G could adversely affect results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G are engaged in activities for which they have claimed, and expect to claim in the future, research and experimentation tax deductions and credits and tax abandonment losses, all of which are the subject of uncertainty and which may be considered controversial by the taxing authorities. The outcome of those uncertainties could adversely impact cash flows, results of operations and financial condition.

The Company and Consolidated SCE&G have claimed significant research and experimentation tax deductions and credits related to the design and construction activities of Unit 2 and Unit 3. A significant portion of these claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. (See also Note 5 to the consolidated financial statements.) The Company and Consolidated SCE&G also expect to claim a significant tax deduction related to the decision to stop construction and to abandon the Nuclear Project in 2017.

These tax claims primarily involve the timing of recognition of tax deductions rather than permanent tax attributes, and their permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to them, had been deferred within regulatory assets. As such, until December 31, 2017 when it was determined to treat these deferrals as impaired (see Note 10 to the consolidated financial statements), these claims had not had, and were not expected to have in the future, significant direct effects on the Company's and Consolidated SCE&G's results of operations. Nonetheless, the claims have contributed significantly to the Company's and Consolidated SCE&G's cash flows by providing a significant source of capital and lessening the level of debt and equity financing that the Company and Consolidated SCE&G have needed to raise in the financial markets.

The claims made to date are under examination and are considered controversial by the IRS. Tax deductions which are expected to be claimed in connection with the determination to abandon the construction of Unit 2 and Unit 3 may also be considered controversial; therefore, it is also expected that the IRS will examine future tax returns. To the extent that any of these claims are not sustained as ordinary losses on examination or through any subsequent appeal, the Company and Consolidated SCE&G will be required to repay any cash received for tax benefit claims which are ultimately disallowed, along with interest on those amounts. Such amounts could be significant and could adversely affect the Company's and Consolidated SCE&G's liquidity, cash flows, results of operations and financial condition. In certain circumstances, which management considers to be remote, penalties for underpayment of income taxes could also be assessed. Additionally, in such circumstances, the Company and Consolidated SCE&G may need to access the capital markets to fund those tax and interest payments, which could in turn adversely impact their ability to access capital markets for other purposes.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing NO_X, SO_2, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. No new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. On October 10, 2017, the Administrator of the EPA signed a notice proposing to repeal the rule on the grounds that it exceeds the EPA's statutory authority. The EPA is further considering the scope of any potential replacement rule and plans to formally solicit information on systems of emission reduction that are in accord with the EPA's interpretation of its statutory authority. However, a number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none has yet been enacted. In April 2012, the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. The EPA's rule for cooling water intake structures to meet the best technology available became effective in October 2014, and the EPA also issued a final rule in December 2014 regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA finalized new standards under the CWA governing effluent limitation guidelines for electric generating units in September 2015. The rule setting forth these new standards has been stayed administratively, and the EPA has begun a new rulemaking process that could take until 2020 before revisions to the effluent limitation guidelines for electric generating units is complete.

Compliance with these environmental laws and regulations requires us to commit significant resources toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements, additional regulations and related costs, or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as more stringent clean-up of contaminated sites or reduced emission allowances) or require us to incur additional expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our businesses and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed. Additionally, there can be no assurance that a federal tax or fee for carbon emitting generating facilities will not be imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. Such renewable energy may not be readily available in our service territories and could be costly to build, finance, acquire, integrate, and/or operate. Resulting increases in the price of electricity to recover the cost of these types of generation, and the costs of their integration to the electric system, could result in lower usage of electricity by our customers. In addition, DER generation at customers' facilities could result in the loss of sales to those customers. Compliance with potential future portfolio standards could significantly impact our capital expenditures and our results of operations and financial condition. Utility scale solar development companies are currently working in South Carolina to develop projects in SCE&G's service territory. The integration of those resources at high penetration levels may be challenging.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In turn, they affect the costs and rates of the Company and Consolidated SCE&G. In effecting compliance with MATS, SCE&G has retired three of its oldest and smallest coal-fired units and converted three others such that they are gas-fired.

Commodity price changes, delays in delivery of commodities, commodity availability and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs), availability and deliverability. Any such changes could affect the prices these businesses charge, their operating costs, and the competitive position of their products and services. In addition, the abandonment of the Nuclear Project may heighten the Company's and Consolidated SCE&G's future exposure to volatility in prices of non-nuclear commodities such as natural gas. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to result in the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial condition.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternate forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers on a volumetric rate structure unable to switch to alternate fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G. A regulatory mechanism applies to residential and commercial customers at PSNC Energy to mitigate the earnings impact of an increase or decrease in gas usage.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, the Department of Homeland Security, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental agencies, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our businesses. In addition to many other aspects of our businesses, these requirements impact the services mandated or offered to our customers, and the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the pricing of utility services, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. Non-compliance with these requirements by third parties, such as our contractors, vendors and agents, may subject the Company and Consolidated SCE&G to operational risks and to liability. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's or Consolidated SCE&G's businesses. Non-compliance with these laws and regulations could result in fines, litigation, loss of licenses or permits, mandated capital expenditures and other adverse business outcomes, as well as reputational damage, which could adversely affect the cash flows, results of operations, and financial condition of the Company and Consolidated SCE&G.

Furthermore, changes in or uncertainty in monetary, fiscal, tax, economic, trade, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G also could be adversely impacted by changes in tax policy, or taxes related to the usage of certain fuel types in our businesses or our ownership and/or operation of certain types of generating facilities. Future, unknown regulation of hydraulic fracturing activities also could impact the operations and finances of the Company and Consolidated SCE&G.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects (including the abandonment of Unit 2 and Unit 3 as previously described), results of DSM Programs, results of DER programs, and/or increases in operating costs may lead to requests for regulatory relief and any related administrative or legislative action, decision, regulation or law affecting rates, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits. Additionally, in 2017, several legislative proposals were introduced that are being or are expected to be considered by the South Carolina General Assembly in 2018. In the event certain provisions of these legislative proposals were to become law as proposed, such provisions could adversely impact SCE&G's rate recovery with respect to the Nuclear Project. Furthermore, there can be no assurance that other legislation which might modify or repeal the BLRA in a manner which would adversely impact SCE&G's rate recovery, including its reasonable return on costs, with respect to its abandonment of Unit 2 and Unit 3 will not be proposed and passed. Any such action could also result in a failure to consummate the merger.

SCE&G's electric operations in South Carolina and the Company's gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the ability of SCE&G to recover the cost of the Nuclear Project, including abandonment costs, and a reasonable return on those costs, is subject to rate regulation by the SCPSC. Consolidated SCE&G's generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. SCE&G's electric transmission system is subject to extensive regulations and oversight from the SCPSC, NERC and FERC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as market conditions evolve.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement, many of which are still pending final action by those federal agencies. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers and major swap participants, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers or major swap participants, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Our ability to charge customer rates that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards related to compliance with laws and regulations, ethical conduct, operational effectiveness, customer service and the safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company's and Consolidated SCE&G's access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to assure reliability of provided services, to focus on the safety of employees, customers and the public, to ensure environmental compliance, to maintain the physical and cyber security of their operations and assets, to maintain the privacy of information related to our customers and employees, and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. Traditional news media and social media can very rapidly convey information, whether factual or not, to large numbers of people, including customers, investors, regulators, legislators and other stakeholders, and the failure to effectively manage timely, accurate communication through these channels could adversely impact our reputation. The Company and Consolidated SCE&G also are committed to operational excellence, to quality customer service, and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments, or a perceived failure to meet these commitments, may subject the Company and Consolidated SCE&G not only to fraud, regulatory action, litigation or financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

A failure of the Company and Consolidated SCE&G to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows.

The Company and Consolidated SCE&G depend on maintaining the physical and cyber security of their operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our businesses could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's and Consolidated SCE&G's operations are dependent in some manner upon our cyber systems, which encompass electric and gas operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company and Consolidated SCE&G, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, vendor, shareholder, employee, or corporate information. The Company and Consolidated SCE&G may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to mitigate the adverse impacts of these events. As a result, the Company's and Consolidated SCE&G's financial condition, results of operations, and cash flows may be adversely affected.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and we may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company's and Consolidated SCE&G's business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company's and Consolidated SCE&G's ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA's pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition, including its shareholders' equity.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and, in deregulated markets, received lower prices for natural gas when weather conditions have been milder than normal, and as a consequence earned less income from those operations. Mild weather in the future could adversely impact the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as hurricanes or other significant weather events, electromagnetic events, the 2011 earthquake and tsunami in Japan or fires) or man-made mishaps (such as natural gas transmission pipeline failure, electric utility companies' ash pond failures, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial condition, operating expenses, and cash flows.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction and environmental compliance, are significant, and these projects are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of these projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in electric generation and in other internal infrastructure projects, including projects for environmental compliance. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and construction schedules may be affected by many variables, such as the regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness and/or financial stability, unforeseen difficulties meeting critical regulatory requirements, contract disputes and litigation, and changes in key contractors or subcontractors. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, adverse changes in applicable laws and regulations, new or enhanced environmental or regulatory requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. To the extent that, in connection with the construction of a project, delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete the project, our results of operations, cash flows and financial condition, as well as our qualifications for applicable governmental programs, benefits and tax credits may be adversely affected.

A significant portion of Consolidated SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition.

SCE&G jointly owns and is the operator of Unit 1. Various risks of nuclear generation to which SCE&G is subject include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;

- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and suppliers thereof, fabrication of nuclear fuel and related vendors, and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate;
- Uncertainties with respect to possible future increased regulation of nuclear facilities and nuclear generation, and related costs thereof; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In today's environment, there is a heightened risk of terrorist attack on the nation's nuclear facilities, which has resulted in increased security costs at our nuclear plant. Although we have no reason to anticipate a serious nuclear incident, a major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit, resulting in costly changes to units in operation and adversely impacting our results of operations, cash flows and financial condition. Furthermore, a major incident at a domestic nuclear facility could result in retrospective premium assessments under our nuclear insurance coverages.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via an RTO/ISO is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should an RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina or North Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets could be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems, which systems have undergone a rapid decline in their costs. As a result of federal and state subsidies, potential regulations allowing third-party retail sales, and advances in distributed generation technology, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and will slow growth, potentially causing higher rates to customers.

The Company and Consolidated SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and Consolidated SCE&G, which may be affected by regional, national or even international economic factors. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in higher costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. Also, in connection with the pending merger, some customers or vendors of the Company and Consolidated SCE&G may delay or defer decisions, which could negatively impact the revenues, earnings, cash flows and expenses of the Company and Consolidated SCE&G regardless of whether the merger is completed. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally, legislative actions (including tax reform), or regulatory actions. Industrial and commercial customer growth also potentially is affected by the availability of "clean" energy options in our service territory. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns. For instance, improvements in energy storage technology, if realized, could have dramatic impacts on the viability of and growth in distributed generation.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms that are attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be adversely impacted.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission equipment failure, information systems failure or security breach, operator error, natural disasters, and the effects of a pandemic, terrorist attack or cyber attack on our workforce or facilities or on vendors and suppliers necessary to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The integration of a significant amount of distributed generation into our systems may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a natural gas line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's and Consolidated SCE&G's revenues, results of operations, cash flows, and financial condition. Insurance may not be available or adequate to mitigate the adverse impacts of these events.

SCANA's ability to pay dividends and to make payments on SCANA's debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital.

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SCANA Energy, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Further, SCANA has agreed to obtain the consent of Dominion Energy, which consent cannot be unreasonably withheld, prior to making dividend payments to shareholders greater than $0.6125 per share for any quarter while the Merger Agreement is pending. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e., natural gas) market risk. We could be required to provide cash collateral or recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract. We could also be required to provide additional cash collateral if credit rating agency downgrades of our debt trigger more stringent requirements.

The Company strives to manage commodity price exposure by establishing risk limits and utilizing various financial instruments (exchange traded and over-the-counter instruments) to hedge physical obligations and reduce price volatility. We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be adversely impacted.

Failure to retain and attract key personnel could adversely affect the Company's and Consolidated SCE&G's operations and financial performance, particularly in light of uncertainties related to and resulting from abandonment of the Nuclear Project and the pending merger.

A significant portion of our workforce will be eligible for retirement during the next few years. Uncertainties related to regulatory, legislative and legal proceedings, as well as the proposed merger, also weigh significantly on the employment considerations made by current and prospective employees. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our businesses. Competition for these employees is high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. Further, the Company's or Consolidated SCE&G's ability to construct or maintain generation or other assets requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance. Furthermore, increased medical benefit costs of employees and retirees could adversely affect the results of operations of the Company and Consolidated SCE&G. Medical costs in this country have risen significantly over the past number of years and are expected to continue to increase at unpredictable rates. Such increases, unless satisfactorily managed by the Company and Consolidated SCE&G, could adversely affect results of operations.

The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial condition, and access to capital.

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes, including customers' concerns regarding rate increases, such as the current environment relating to proposed recovery of costs, and a reasonable return on those costs, under the abandonment provisions of the BLRA or through other means, may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously supported by legislation or approved by regulators), to the detriment of the Company or Consolidated SCE&G (e.g., revision or repeal of the BLRA). In addition, operating covenants in the Merger Agreement require the consent of Dominion Energy prior to SCANA taking certain actions, which consent cannot be unreasonably withheld, during the pendency of the merger. As a result, the Company and Consolidated SCE&G may be unable to pursue strategic transactions, undertake significant capital projects, undertake certain significant financing or other specified transactions or pursue actions that are not in the ordinary course of business even if such actions would prove beneficial. Further, the Company's and Consolidated SCE&G's management may be focused on completion of the merger, which could lead to the disruption of ongoing business or inconsistencies in service, standards, controls, procedures and policies, any of which could adversely affect the ability of the Company and Consolidated SCE&G to maintain relationships with customers, regulators, vendors and employees, or could otherwise adversely affect their business and financial results, without realizing any of the benefits of having the merger completed. Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company's or Consolidated SCE&G's interests, may have a negative effect on our results of operations, cash flows and financial condition, as well as limit our ability to access capital.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds directly all of the capital stock of each of its subsidiaries.

SCE&G's bond indenture, which secures its First Mortgage Bonds, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

Electric Properties

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2017.

	In-Service Date	Net Generating Capacity Summer (MW)
Coal-Fired Steam:		
Wateree - Eastover, SC	1970	684
Williams - Goose Creek, SC	1973	605
Cope - Cope, SC	1996	415
Kapstone - Charleston, SC	1999	85
Gas-Fired Steam:		
McMeekin - Irmo, SC	1958	250
Urquhart Unit 3 - Beech Island, SC	1953	95
Nuclear:		
Summer Station Unit 1 - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647
Internal Combustion Turbines:		
Jasper Combined Cycle - Jasper, SC	2004	852
Urquhart Combined Cycle - Beech Island, SC	2002	458
Peaking units - various locations in SC	1968-2010	348
Hydro:		
Fairfield Pumped Storage - Parr, SC	1978	576
Saluda - Irmo, SC	1930	200
Other - various locations in or bordering SC	1905-1914	18

SCE&G owns 436 substations having an aggregate transformer capacity of 32.1 million Kilovolt ampere. The transmission system consists of 3,469 miles of lines, and the distribution system consists of 18,559 pole miles of overhead lines and 7,622 trench miles of underground lines.

Natural Gas Distribution and Transmission Properties

SCE&G's natural gas system includes 447 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and DECG. SCE&G’s distribution system consists of 17,671 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6,180 MMBTU per day and store the liquefied equivalent of 1,009,400 MMBTU of natural gas. The Salley facility can store the liquefied equivalent of 927,000 MMBTU of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 61,800 MMBTU per day at Charleston and 92,700 MMBTU per day at Salley.

PSNC Energy's natural gas system consists of 607 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy's distribution system consists of 22,141 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000,000 MMBTU, the capacity to liquefy up to 4,000 MMBTU per day and the capacity to regasify approximately 100,000 MMBTU per day.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G:

The following describes certain legal proceedings through December 31, 2017. The Company and Consolidated SCE&G intend to vigorously contest the lawsuits which have been filed against them. For developments related to these or other proceedings subsequent to December 31, 2017, see Note 2 and Note 10 to the consolidated financial statements. No reference to, or disclosure of, any proceeding, item or matter described below shall be construed as an admission or indication that such proceeding, item or matter is material or that such proceeding, items or matter is required to be referred to or disclosed in this Form 10-K.

Ratepayer Class Actions

On August 11, 2017, a purported class action was filed against SCE&G by plaintiff LeBrian Cleckley (the "Cleckley Lawsuit"), on behalf of himself and all others similarly situated, in the State Court of Common Pleas in Richland County, South Carolina (the "Richland County Court"). The plaintiff alleges, among other things, that SCE&G was negligent and unjustly enriched and breached alleged fiduciary and contractual duties by failing to properly manage the Nuclear project. The plaintiff seeks to recover, on behalf of the purported class, unspecified damages and attorneys' fees, specific performance of the alleged implied contract to construct the now abandoned project, and any other relief the court deems proper. At December 31, 2017, SCE&G's amended motion to dismiss was scheduled to be heard on January 8, 2018. Also at December 31, 2017, the following additional motions were pending: SCE&G's Motion for Protective Order, filed October 2, 2017; Plaintiff's Motion to Compel Discovery, filed October 20, 2017; and Plaintiff's Motion to Appoint a Receiver, filed November 1, 2017. By order dated October 31, 2017, the South Carolina Supreme Court consolidated all pending state court ratepayer class actions and assigned the consolidated cases to a single Circuit Court judge.

On August 14, 2017, a purported class action was filed against SCE&G by plaintiff Richard Lightsey (the "Lightsey Lawsuit"), on behalf of himself and all others similarly situated, in the State Court of Common Pleas in Hampton County (the "Hampton County Court"). The plaintiff makes substantially similar allegations as those alleged in the Cleckley Lawsuit and, in addition, alleges that SCE&G committed unfair trade practices and violated state anti-trust laws. The plaintiff seeks a declaratory judgment that SCE&G may not charge its customers for any past or continuing costs of the Nuclear Project. The plaintiff also seeks compensatory, punitive and statutory treble damages, attorneys' fees, and any other relief the court deems proper. On August 25, 2017, SCE&G filed a motion to transfer venue to Lexington County, South Carolina. At December 31, 2017, the following motions were pending: Plaintiff's Motion for Class Certification, filed August 23, 2017; SCE&G's Motion to Dismiss, etc., filed September 14, 2017; SCE&G's Motion for Protective Order, filed September 26, 2017; Plaintiff's Motion to Compel, filed October 12, 2017; and SCE&G's Motion to Dismiss, etc., Second Amended Complaint, filed October 24, 2017.

On August 28, 2017, a purported class action was filed against SCANA and SCE&G by plaintiff Edwinda Goodman, on behalf of herself and all others similarly situated, in the State Court of Common Pleas in Fairfield County (the "Fairfield County Court"). The plaintiff makes substantially similar allegations as those alleged in the Cleckley Lawsuit and, in addition, alleges that SCE&G committed fraud and misrepresentation in failing to properly manage the Nuclear Project. The plaintiff seeks to have the defendants' assets frozen and all monies recovered from Toshiba and other sources be placed in a constructive trust for the benefit of ratepayers. The plaintiff also seeks compensatory, punitive and treble damages, attorneys' fees, and any other relief the court deems proper. At December 31, 2017, the following motions were pending: SCE&G's Motion to Dismiss and Strike, filed October 2, 2017; SCE&G's Motion for Protective Order, filed October 2, 2017; and Plaintiff's Motion to Appoint Receiver and Expedite Hearing, served November 2, 2017.

On September 7, 2017, a purported class action was filed against Santee Cooper, SCE&G, Palmetto Electric Cooperative, Inc. and Central Electric Power Cooperative, Inc. by plaintiff Jessica Cook, on behalf of herself and all others similarly situated, in the Hampton County Court. The plaintiff makes substantially similar allegations as the Cleckley Lawsuit and the Lightsey Lawsuit. The plaintiff seeks a declaratory judgment that defendants may not charge the purported class for reimbursement for past or future costs of the Nuclear Project, as well as other compensatory and statutory treble damages, attorneys' fees, and any other relief the court deems proper. At December 31, 2017, the following motions were pending: SCE&G's Motion to Dismiss and to Strike, filed October 11, 2017; SCE&G's Motion for Protective Order, filed October 11, 2017; Santee Cooper's Motion to Dismiss Third Amended Complaint, filed October 24, 2017; Plaintiff's Motion for Default Judgment against Central Electric Power Cooperative, filed November 1, 2017; and Central Electric Power Cooperative, Inc.'s Motion to Dismiss Third Amended Complaint, filed November 16, 2017.

Also on September 7, 2017, a purported class action was filed against Santee Cooper and SCANA by plaintiffs Hope Brown and Thomas Lott, on behalf of themselves and all others similarly situated, in the Richland County Court. The plaintiffs allege, among other things, that SCE&G conspired with Santee Cooper to unlawfully deprive plaintiffs of their property rights guaranteed under the United States and South Carolina Constitutions and were unjustly enriched by the Nuclear Project. The plaintiffs seek disgorgement of all monies spent by defendants on the project, as well as other compensatory and punitive damages, attorneys' fees, and any other relief the court deems proper. Plaintiffs' counsel voluntarily dismissed this action without prejudice on November 12, 2017.

On September 25, 2017, a purported class action was filed against SCANA by plaintiff Christine Delmater, on behalf of herself and all others similarly situated, in the District Court. The plaintiff alleges, among other things, that SCE&G violated provisions of the Racketeer Influenced and Corrupt Organizations Act 18 U.S.C. §1961, was negligent, breached alleged contractual duties, and was unjustly enriched by failing to properly manage the Nuclear Project. The plaintiff seeks compensatory and consequential damages, and any other relief the court deems proper. Plaintiff filed its Second Amended Complaint on November 7, 2017, and filed a Motion for Injunctive Relief on November 8, 2017. Following extensions, responsive pleadings to the Second Amended Complaint and the Motion for Injunctive Relief were filed December 21, 2017.

On October 9, 2017, plaintiffs Chris Kolbe and Ruth Ann Keffer filed an amended complaint in a purported class action, on behalf of themselves and all others similarly situated, against Santee Cooper and certain of its directors and officers, in the Berkeley County Court of Common Pleas, naming SCE&G and SCANA as additional defendants. The plaintiffs allege, among other things, that SCE&G and SCANA were grossly negligent, reckless, breached contracts, were unjustly enriched, and violated principles of equity in connection with their management of the Nuclear Project. The plaintiffs seek compensatory damages and attorneys' fees, and a declaratory judgment as to Santee Cooper's rates. SCANA and SCE&G filed a Motion to Dismiss and to Strike on November 17, 2017.

Shareholder Derivative and 10b-5 Class Actions

On September 26, 2017, a purported shareholder derivative action was filed against defendants Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynne Miller, James Roquemore, Maceo Sloan, Alfredo Trujillo, Jimmy Addison, Stephen Byrne, and nominal defendant SCANA by plaintiff John Crangle, purportedly on behalf of SCANA, in the Richland County Court (the "Crangle Lawsuit"). The plaintiff alleges, among other things, that the defendants breached their fiduciary duties to shareholders by their gross mismanagement of the Nuclear Project, and that the defendants Marsh, Addison, and Byrne were unjustly enriched by bonuses they were paid in connection with the project. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper. Defendants filed motions to dismiss the complaint in December 2017.

On September 27, 2017, a purported class action was filed against SCANA, Kevin B. Marsh, Jimmy E. Addison, and Stephen A. Byrne by plaintiff Robert L. Norman, on behalf of himself and all others similarly situated, in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants are liable under §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On October 5, 2017, a purported class action was filed against SCANA, Kevin B. Marsh, and Jimmy E. Addison by plaintiff Kenneth Evans on behalf of himself and all others similarly situated in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants violated §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On October 30, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynn Miller, James Roquemore, Maceo Sloan, Aldredo Trujillo, Jimmy Addison, Stephen Byrne, and SCANA by plaintiff R. Wayne Todd, purportedly on behalf of SCANA in Richland County Court (the "Todd Lawsuit"). The plaintiff makes substantially similar allegations as those alleged in the Crangle Lawsuit, and alleges that the defendants Marsh, Addison, and Byrne were unjustly enriched by bonuses they were paid in connection with the Nuclear Project. The plaintiff seeks compensatory and consequential damages, punitive damages, attorneys' fees, and any other relief the court deems proper. Defendants filed motions to dismiss the complaint in December 2017.

On November 10, 2017, a purported class action was filed against SCANA, Kevin Marsh, Jimmy Addison, and Steve Byrne by plaintiff Marsha Fox on behalf of herself and all others similarly situated in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants violated §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On November 17, 2017, a purported class action was filed against SCANA, Kevin B. Marsh, Jimmy E. Addison, and Steve B. Byrne by plaintiff West Palm Beach Firefighters' Pension Fund on behalf of itself and all others similarly situated in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants violated §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On November 21, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynn Miller, James Roquemore, Maceo Sloan, Aldredo Trujillo, Jimmy Addison, Stephen Byrne, and SCANA by plaintiff Colleen Witmer, purportedly on behalf of SCANA in the District Court. The plaintiff alleges, among other things, that the defendants violated their fiduciary duties to shareholders by disseminating false and misleading information about the Nuclear Project, failing to maintain proper internal controls, failing to properly oversee and manage the company, and that the individual defendants were unjustly enriched in their compensation. The plaintiff seeks compensatory and consequential damages, disgorgement of compensation, punitive damages, attorneys' fees, and any other relief the court deems proper.

On November 22, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynn Miller, James Roquemore, Maceo Sloan, Aldredo Trujillo, and SCANA by plaintiff Richard Wickstrom, purportedly on behalf of SCANA in the District Court. The plaintiff alleges, among other things, that the defendants violated their fiduciary duties to shareholders by affirmatively making and allowing material misstatements to be made to shareholders regarding the Nuclear Project. The plaintiff seeks compensatory and consequential damages, disgorgement of Marsh's compensation, attorneys' fees, and any other relief the court deems proper.

On December 5, 2017, a purported shareholder derivative action was filed against Kevin B. Marsh, Stephen A. Byrne, Jimmy Addison, Gregory E. Aliff, James A. Bennett, John F.A.V. Cecil, Sharon A. Decker, D. Maybank Hagood, Lynne M. Miller, James W. Roquemore, Maceo K. Sloan, Aldredo Trujillo, James M. Micali, Harold C. Stowe, and nominal defendant SCANA by plaintiff City of Hollywood Employees Retirement Fund in the District Court. The plaintiff alleges, among other things, that the defendants violated their fiduciary duties to shareholders by their gross mismanagement of the Nuclear Project, committed corporate waste, were unjustly enriched, and that the director defendants violated Section 14(a) of the Exchange Act and SEC Rule 14a-9 by allowing or causing misleading proxy statements to be issued in 2016 and 2017. Plaintiff seeks equitable and injunctive relief related to corporate governance functions, as well as compensatory and consequential damages, disgorgement of compensation, attorneys' fees, and any other relief the court deems proper.

On December 13, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Jimmy Addison, Stephen Byrne, Maybank Hagood, Lynne Miller, James Bennett, Maceo Sloan, Sharon Decker, James Roquemore, Alfredo Trujillo, John F.A.V. Cecil, Gregory Aliff, James Micali, Harold Stowe, and nominal defendant SCANA by plaintiff Firemen's Retirement System of St. Louis, purportedly on behalf of SCANA, in the Richland County Court. The plaintiff makes substantially similar allegations as those alleged in the Crangle and Todd Lawsuits. The plaintiff seeks compensatory and consequential damages, injunctive relief, restitution, attorneys' fees, and any other relief the court deems proper.

Contractor Lien Litigation

On April 27, 2017, SCE&G filed a declaratory judgment lawsuit in the Fairfield County Court against Structural Preservation Systems, Inc., a subcontractor to WECTEC and several dozen other companies that were WECTEC subcontractors, or who otherwise provided such labor and materials for other companies for the use and benefit of WECTEC (collectively, the "WECTEC Subcontractors"), who claimed that WECTEC had not paid them for work on the Nuclear Project.

The lawsuit was filed for the purpose of asserting SCE&G's common defenses to such claims by the WECTEC Subcontractors that WECTEC owed them payment for labor or materials they supplied on the project. Since that time, more than 40 individual cases have been filed by WECTEC Subcontractors against SCE&G and Santee Cooper asserting statutory and common law claims against both entities for alleged non-payment by WECTEC. On September 29, 2017, SCE&G obtained a court order consolidating all current and future lawsuits among SCE&G, Santee Cooper, and the WECTEC Subcontractors arising out of allegations of non-payment of the WECTEC Subcontractors by WEC. SCE&G also obtained a court order that designated all such lawsuits as complex and assigning them to one judge. Finally, SCE&G obtained a third court order that stayed any party's otherwise required response to any lawsuit, claim, cross-claim, counterclaim, or third party claim in these lawsuits until the parties could work on case management issues and present a plan for case management to the judge assigned the cases. The lawsuits are in the pleadings stage. The WECTEC Subcontractors have made claims including but not limited to foreclosure of mechanics liens, common law theories including but not limited to negligence and breach of contract, equitable theories including the imposition of a constructive trust on the Toshiba settlement proceeds, damages, and injunctive relief.

FILOT Litigation

On November 29, 2017, Fairfield County filed a Complaint and a Motion for Temporary Injunction against SCE&G making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of the implied duty of good faith and fair dealing, and unfair trade practices related to SCE&G's termination of the FILOT agreement. Plaintiff sought a temporary and permanent injunction to prevent SCE&G from terminating the FILOT; actual and consequential damages; treble damages; punitive damages; and attorneys' fees. Plaintiff sought a hearing within ten days on their motion for temporary injunction. The Court heard arguments on December 15, 2017 on the motion for temporary injunction, and asked the parties to submit supplemental briefing and proposed orders by December 20, 2017. Plaintiff voluntarily withdrew the Motion for Temporary Injunction on December 20, 2017. The Court set a hearing for February 8, 2018 on SCE&G's Motion to Transfer Venue.

Regulatory Proceedings and Investigations

On June 22, 2017, the Friends of the Earth and the Sierra Club filed a complaint against SCE&G with the SCPSC, requesting that the SCPSC initiate a formal proceeding to direct SCE&G to immediately cease and desist from expending any further capital costs related to the construction of Unit 2 and Unit 3; to determine the prudence of acts and omissions by SCE&G in connection with the construction of Unit 2 and Unit 3; to review and determine the prudence of abandonment of the Nuclear Project and of the available least cost efficiency and renewable energy alternatives; and to remedy, abate and make due reparations for the rates charged to ratepayers related to the construction of Unit 2 and Unit 3. SCE&G filed its answer to the complaint on July 19, 2017. SCE&G has filed a motion to dismiss the plaintiff's complaint, which motion was argued at a hearing held on December 13, 2017. On December 20, 2017, the SCPSC, among other things, denied SCE&G's motion to dismiss and ordered that the matter be consolidated with proceedings related to the Request, described below.

On September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon an opinion of the South Carolina Office of Attorney General issued on the same date, to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the South Carolina General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed with the SCPSC a motion to amend its request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. A hearing on the parties' motions was held on December 12, 2017, and included the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, a large industrial customer, and several environmental groups. In addition, on November 20, 2017, the ORS filed a letter with the SCPSC providing ORS's preliminary list for stabilization and protection of the site containing Unit 2 and Unit 3 and suggesting that the SCPSC have SCE&G respond to ORS's November 20, 2017 letter and "explain why there is no violation of S.C. Code Ann. § 58-27-1300." The SCPSC granted ORS's request, and SCE&G filed its response with the SCPSC on December 27, 2017.

By order dated December 20, 2017, the SCPSC denied SCE&G's Motion to Dismiss the Request and ordered that a hearing be set on the Request. In addition, the SCPSC ordered ORS to perform a thorough inspection and audit, within 30 days, to determine the reasonableness of SCE&G's retail electric rates and to determine the reasonableness of SCE&G's statements regarding the potential effect that the removal of approximately $445 million in annual revenues, as requested by the ORS, could have on SCE&G. The SCPSC also granted ORS's motion to amend the Request and consider the monetization of the Toshiba payout along with any other related factors that may be appropriate in determining a fair and reasonable rate. Lastly, the order consolidated the Friends of the Earth and Sierra Club petition with the Request.

The Company has also been served with subpoenas issued by the United States Attorney's Office for the District of South Carolina and the staff of the SEC's Division of Enforcement seeking documents relating to the Nuclear Project. In addition, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee have requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. The Company and Consolidated SCE&G intend to fully cooperate with any such investigations.

On November 30, 2017, the SCPSC served upon SCE&G a document styled as "South Carolinians Against Monetary Abuse (SCAMA) and Leslie Minerd v. South Carolina Electric & Gas Company" requesting that SCE&G include a line item on customers' monthly bill identifying the charges incurred as a result of the BLRA. On December 29, 2017, SCE&G filed its Answer and Motion to Dismiss and requested that the testimony deadlines and hearing date be held in abeyance pending a determination on SCE&G's Motion to Dismiss.

Bankruptcy Court Litigation

On March 29, 2017, WEC and WECTEC and certain of their affiliates filed petitions for protection under Chapter 11 of the U.S. Bankruptcy Code with the Bankruptcy Court. On September 1, 2017, SCE&G, for itself and as agent for Santee Cooper, filed with the Bankruptcy Court Proofs of Claim for unliquidated damages against each of WEC and WECTEC. The Proofs of Claim are based upon the anticipatory repudiation and material breach by the Consortium of the EPC Contract, and assert against WEC any and all claims that are based thereon or that may be related thereto. On September 27, 2017, SCE&G sold substantially all of its interest in the Toshiba Settlement and assigned all of its claims under the WEC bankruptcy process to Citibank. SCE&G has agreed to use commercially reasonable efforts to cooperate with Citibank and provide reasonable support necessary for its enforcement of those claims. Notwithstanding the sale of the claims, SCE&G and Santee Cooper remain responsible for any claims that may be made by WEC and WECTEC against them relating to the EPC Contract.

Employment Class Action

On August 8, 2017, a purported class action was filed against SCANA, SCE&G, and its co-defendants Fluor and Fluor Enterprises, Inc., by plaintiffs Harry Pennington III and Timothy Lorenz, on behalf of themselves and all others similarly situated, in the District Court. The plaintiffs allege, among other things, that the defendants violated the Worker Adjustment and Retraining Notification Act ("WARN Act") in connection with the decision to stop construction on the Nuclear Project. The plaintiffs allege that the defendants failed to provide adequate advance written notice of their terminations of employment.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all wholly-owned subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Jimmy E. Addison	57	Chief Executive Officer and President-SCANA	2018-present
		President and Chief Operating Officer-SCANA Energy	2014-2018
		Executive Vice President-SCANA and Chief Financial Officer	*-2017
Jeffrey B. Archie	60	Senior Vice President and Chief Nuclear Officer-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Sarena D. Burch	60	Senior Vice President-Risk Management and Corporate Compliance	2016-present
		Senior Vice President-Fuel Procurement and Asset Management-SCANA, SCE&G and PSNC Energy	*-2015
Iris N. Griffin	41	Senior Vice President, Chief Financial Officer and Treasurer	2018-present
		Vice President - Finance and Treasurer	2016-2017
		Associate Treasurer	2015-2016
		Director - Audit Services, Privacy and Corporate Compliance Officer	2013-2015
		Manager - Investor Relations	*-2013
D. Russell Harris	53	President-Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		President and Chief Operating Officer-SCANA Energy	2018-present
		Senior Vice President-SCANA	2013-present
Kenneth R. Jackson	61	Senior Vice President-Economic Development, Governmental and Regulatory Affairs	2014-present
		Vice President-Rates and Regulatory Services	*-2014
W. Keller Kissam	51	President-Generation, Transmission and Distribution and Chief Operating Officer-SCE&G	2018-present
		President-Retail Operations-SCE&G	*-2017
		Senior Vice President-SCANA	*-present
Randal M. Senn	61	Senior Vice President-Administration-SCANA	2016-present
		Vice President and Chief Information Officer	2016
		Chief Information Officer	*-2016
Jim Odell Stuckey	49	Senior Vice President, General Counsel and Assistant Secretary	2017-present
		Director - Legal Department and Deputy General Counsel	2014-2017
		Director - Legal Department and Associate General Counsel	*-2014

*Indicates positions held at least since February 23, 2013.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

SCANA:

Price Range (NYSE Composite Listing):

	2017				2016			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 50.22	$ 68.35	$ 71.28	$ 72.75	$ 74.94	$ 76.41	$ 75.67	$ 70.35
Low	$ 37.10	$ 48.32	$ 63.90	$ 63.63	$ 67.31	$ 69.04	$ 66.02	$ 59.46

SCANA common stock trades on the NYSE using the ticker symbol SCG. At February 20, 2018 there were approximately 143 million shares of SCANA common stock outstanding which were held by approximately 23,100 shareholders of record. See Item 12 for a summary of equity securities issuable under SCANA's compensation plans at December 31, 2017.

SCANA declared quarterly dividends on its common stock of $0.6125 per share in 2017 and $0.575 per share in 2016. On February 22, 2018, SCANA declared a quarterly cash dividend on SCANA common stock of $0.6125 per share, which quarterly dividend is payable April 1, 2018 to shareholders of record on March 12, 2018. For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

The following table provides information about purchases by or on behalf of SCANA or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended (Exchange Act)) of shares or other units of any class of SCANA's equity securities that are registered pursuant to Section 12 of the Exchange Act:

Issuer Purchases of Equity Securities

Period	(a) Total number of shares (or units) purchased	(b) Average price paid per share (or unit)	(c) Total number of shares (or units) purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1-31, 2017	7,964	$ 49.01	7,964	
November 1-30, 2017	—	—	—	
December 1-31, 2017	—	—	—	
Total	7,964		7,964	*

*The above table represents shares acquired for non-employee directors under the Director Compensation and Deferral Plan. On December 16, 2014, SCANA announced a program to convert from original issue to open market purchase of SCANA common stock for all applicable compensation and dividend reinvestment plans. This program took effect in the first quarter of 2015 and has no stated maximum number of shares that may be purchased and no stated expiration date.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2017 and 2016, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount
February 16, 2017	$ 76.9 million	February 18, 2016	$ 72.2 million
April 27, 2017	78.1 million	April 28, 2016	73.3 million
August 3, 2017	78.5 million	July 28, 2016	74.0 million
October 26, 2017	80.6 million	October 27, 2016	77.5 million

On February 22, 2018, SCE&G declared a quarterly dividend on its common stock of $71.9 million.

For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2017	2016	2015	2014	2013
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Operations Data					
Operating Revenues	$ 4,407	$ 4,227	$ 4,380	$ 4,951	$ 4,495
Operating Income	$ 87	$ 1,153	$ 1,308	$ 1,007	$ 910
Net Income (Loss)	$ (119)	$ 595	$ 746	$ 538	$ 471
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.6	142.6	142.6	142.6	138.4
Basic Earnings (Loss) Per Share	$ (0.83)	$ 4.16	$ 5.22	$ 3.79	$ 3.40
Diluted Earnings (Loss) Per Share	$ (0.83)	$ 4.16	$ 5.22	$ 3.79	$ 3.39
Dividends Declared Per Share of Common Stock	$ 2.45	$ 2.30	$ 2.18	$ 2.10	$ 2.03
Balance Sheet Data					
Utility Plant, Net	$ 10,648	$ 14,324	$ 13,145	$ 12,232	$ 11,643
Total Assets	$ 18,739	$ 18,707	$ 17,146	$ 16,818	$ 15,127
Total Equity	$ 5,255	$ 5,725	$ 5,443	$ 4,987	$ 4,664
Short-term and Long-term Debt	$ 6,983	$ 7,431	$ 6,529	$ 6,581	$ 5,788
Other Statistics					
Electric:					
Customers (Year-End)	718,822	709,418	698,372	687,800	678,273
Total sales (Million kWh)	22,866	23,458	23,102	23,319	22,313
Generating capability-Net MW (Year-End)	5,233	5,233	5,234	5,237	5,237
Territorial peak demand-Net MW	4,701	4,807	4,970	4,853	4,574
Regulated Gas:					
Customers, excluding transportation (Year-End)	930,790	906,883	881,295	859,186	837,232
Sales, excluding transportation (Thousand Therms)	857,886	890,113	875,218	973,907	921,533
Transportation customers (Year-End)	616	632	627	656	667
Transportation volumes (Thousand Therms)	700,254	674,999	791,402	1,786,897	1,729,399

The comparability of Selected Financial Data is affected by the following:

In 2017, as a result of the decision to stop construction on Unit 2 and Unit 3, approximately $4.7 billion (prior to an estimated impairment loss) was reclassified from construction work in progress within Utility Plant, Net into regulatory assets. In addition, a pre-tax impairment loss of $1.1 billion was recorded. See Note 10 to the consolidated financial statements. Finally, deferred income tax assets and liabilities were remeasured in connection with the enactment of the Tax Act, resulting in an increase in Net Loss of approximately $30 million.

In 2015, a regulated gas operating subsidiary and a non-operating subsidiary were sold, resulting in pre-tax gains totaling approximately $342 million. See Note 1 to the consolidated financial statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pursuant to General Instruction I of Form 10-K, SCE&G is permitted to omit certain information related to itself and its consolidated affiliates called for by Item 7 of Form 10-K, and instead provide a management's narrative explanation of its consolidated results of operation and other information described therein. Such information is presented hereunder specifically for Consolidated SCE&G, but may be presented alongside information presented for the Company generally. Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation and its subsidiaries (other than Consolidated SCE&G).

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

Key Earnings Drivers and Outlook

The outcome of contentious regulatory, legislative and court proceedings stemming from the Company's July 31, 2017 decision to stop construction of Unit 2 and Unit 3 and to seek recovery of its investment in the abandoned Nuclear Project will significantly affect the Company's future earnings. These proceedings could result in the SCPSC ordering SCE&G to cease collecting BLRA-related rates and to immediately refund such amounts previously collected. Such an outcome would likely result in degraded credit ratings with a corresponding higher cost of capital, if such capital were available at all. In 2017, the Company's principal subsidiary, SCE&G, recorded an aggregate pre-tax impairment loss of $1.118 billion related to the abandoned Nuclear Project. These matters are discussed further in Electric Operations below, in Liquidity and Capital Resources herein and in Note 10 to the consolidated financial statements.

On January 2, 2018, SCANA entered into the Merger Agreement with Dominion Energy. Under the terms of that agreement, Dominion Energy would provide the financial support for SCE&G to make a $1.3 billion up-front, one time rate credit to SCE&G's electric customers to be paid within 90 days of the closing of the merger, a $575 million refund along with the benefits of the Tax Act resulting in at least a 5% reduction to SCE&G electric service customers' bills over an eight-year period, and the exclusion from rate recovery of approximately $1.7 billion of costs related to the Nuclear Project. These terms, together with other terms and commitments in the Merger Agreement and the Joint Petition, could resolve many of the outstanding issues related to the Nuclear Project. The Company targets the closing of the merger by the end of 2018. Significant hurdles must be overcome before closing may occur, however, including the receipt of the requisite authorizations, approvals, consents and/or permits from various federal and state regulatory entities and the approval of two-thirds of the shares represented by SCANA's shareholders. Regulatory approvals of the merger may not be obtained on a timely basis or at all, and such approvals may include conditions that could have an adverse effect on the Company and Consolidated SCE&G or result in the abandonment of the merger. No assurance can be provided that the necessary approvals will be obtained or that any required conditions will not have an adverse effect on Consolidated SCE&G following the merger. See additional discussion in Item 1A. Risk Factors and in Note 2 and Note 10 to the consolidated financial statements.

Electric Operations

SCE&G's electric operations primarily generate electricity and provide for its transmission, distribution and sale to approximately 719,000 customers (as of December 31, 2017) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity compared to other energy sources.

Embedded in the rates charged to customers is an allowed regulatory ROE. SCE&G’s allowed ROE in 2017 was 10.25% for non-BLRA rate base. For BLRA-related rate base existing prior to 2016, SCE&G's ROE was 11.0%, and for such rate base arising in 2016, the ROE was 10.5%. As described in Note 2 to the consolidated financial statements, the SCPSC revised SCE&G's ROE for Nuclear Project costs to 10.25%, which was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. No revised rates filing was pursued in 2017. Uncertainties that are expected to adversely impact ROE on BLRA-related rate base are discussed in Abandoned Nuclear Project herein and in Note 10 to the consolidated financial statements.

In 2017, the enactment of federal environmental laws and regulations related to the generation of electricity slowed significantly; however, public sentiment surrounding air quality and water quality remains strong and is expected to continue. Over several years, SCE&G has incurred significant costs and made substantial investments to comply with federal environmental initiatives, including the retirement of certain coal-fired plants and the conversion of others to burn natural gas. In addition, SCE&G has added the renewable energy from several new solar generating facilities at locations throughout its electric service territory. In addition, SCE&G and GENCO have installed pollution control equipment at their remaining coal-fired plants, which have resulted in reduced air emissions. The status of significant environmental laws and regulations and certain initiatives undertaken to ensure compliance with them are described in Environmental Matters herein and in Note 10 to the consolidated financial statements.

Abandoned Nuclear Project

Significant events leading up to the Company's decision to abandon the Nuclear Project include the following:

- On July 1, 2016, SCE&G, on behalf of itself and as agent for Santee Cooper, elected the fixed price option as provided for in the October 2015 Amendment to the EPC Contract, subject to SCPSC approval. The fixed price option was designed to shift the risk of significant cost overruns from SCE&G and Santee Cooper by fixing the total amount to be paid to the Consortium for its entire scope of work on the project, with limited exceptions.

- On November 9, 2016, the SCPSC approved SCE&G's election of the fixed price option.

- On March 29, 2017, WEC and WECTEC filed petitions for protection under Chapter 11 of the U.S. Bankruptcy Code, citing a liquidity crisis arising from project contract losses attributable to the Nuclear Project and similar units being built for an unaffiliated company as a material factor that caused them to seek protection under the bankruptcy laws. As part of their filing, WEC and WECTEC publicly announced their inability to complete Unit 2 and Unit 3 under the fixed price terms of the EPC Contract.

- In connection with the bankruptcy filing, SCE&G, Santee Cooper, WEC and WECTEC entered into an Interim Assessment Agreement under which engineering and construction continued on the project and under which SCE&G and Santee Cooper were provided the right to discuss project status with Fluor and other subcontractors and vendors and to obtain from them relevant project information and documents that had been previously contractually unavailable in order for SCE&G and Santee Cooper to perform comprehensive analyses regarding whether or how to proceed with the project.

- On July 31, 2017, based on the results of its analysis and in light of Santee Cooper's decision to suspend construction on the units, the Company determined to stop the construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with their construction under the abandonment provisions of the BLRA or through other regulatory means.

The Company's decision to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with their construction have been the subject of contentious proceedings before the SCPSC and special committees of the South Carolina legislature. The Governor has likewise asserted, among other things, that the BLRA should be replaced and any further collection of money from customers for the Nuclear Project should be prevented. The SCPSC is actively considering a request that could result in the suspension of rates currently being collected by SCE&G under the BLRA (approximately $445 million annually, which includes collections related to transmission assets expected to be placed into service), that could require the return of such amounts previously collected (approximately $1.9 billion as of December 31, 2017), and that will affect when and in what manner proceeds arising from the Toshiba guaranty (approximately $1.1 billion) will be used for the benefit of SCE&G customers.

Proposals to Resolve Outstanding Issues

On November 16, 2017, SCE&G announced for public consideration a proposal to resolve outstanding issues relating to the Nuclear Project. Under the proposal, SCE&G electric customers were to receive a 3.5% electric rate reduction, the addition of an existing 540-MW natural gas fired power plant by SCE&G with the acquisition cost borne by SCANA shareholders, and the addition of approximately 100-MW of large scale solar energy by SCE&G. The proposal also provided for the recovery of the nuclear construction costs (net of the proceeds of the Toshiba Settlement not utilized for liquidation of project liens) over 50 years. While SCE&G's proposal was not formally submitted for regulatory approval, discussions with key stakeholders over the ensuing weeks indicated that SCE&G's proposal would not be sufficient to resolve the outstanding issues.

On January 2, 2018, SCANA entered into the Merger Agreement with Dominion Energy, and on January 12, 2018, SCE&G and Dominion Energy filed the Joint Petition requesting SCPSC approval of the merger or a finding that either the merger is in the public interest or that there is an absence of harm arising from the merger. In the Joint Petition, among other things, the parties commit to providing an up-front, one time rate credit to SCE&G's electric customers totaling approximately $1.3 billion within 90 days of the merger's closing, at least a 5% reduction in customer bills, shortening the amortization period for recovery of costs related to the Nuclear Project to 20 years, forgoing recovery of approximately $1.7 billion in costs related to the Nuclear Project, and the addition of an existing 540-MW natural gas fired power plant by SCE&G with no initial investment borne by customers. The petition also puts forth other less-favored alternatives for rate recovery in the event the joint proposal were not to be accepted by the SCPSC and the merger were not to be consummated.

The outcome of these matters is uncertain, and any resolution adverse to the Company and Consolidated SCE&G could adversely affect results of operations, cash flows and financial condition. These matters and others are further discussed in Liquidity and Capital Resources and in Note 2 and Note 10 to the consolidated financial statements.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 931,000 retail customers (as of December 31, 2017) in portions of South Carolina and North Carolina in areas covering approximately 35,000 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory ROE for SCE&G of 10.25% and for PSNC Energy of 9.7%.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company's ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at generally low levels for several years. The supply of natural gas from the Marcellus shale basin has prompted Dominion Energy and other companies unaffiliated with SCANA to propose construction of an approximately 600-mile pipeline that would bring natural gas from West Virginia to Virginia and North Carolina. This pipeline is expected to be completed in late 2019 and, if successful, it may drive economic development along its path, including areas within PSNC Energy's service territory, and may serve to assist in keeping natural gas competitively priced in the region.

Gas Marketing

SCANA Energy markets natural gas in the southeast and provides energy-related services to customers, including retail customers in Georgia. Operating results for energy marketing are influenced by customer demand for natural gas and the ability to control costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, the availability of certain pipeline capacity to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the Georgia retail market. SCANA Energy sells natural gas to over 425,000 customers (as of December 31, 2017) throughout Georgia. This market is mature, resulting in low margins and significant competition from affiliates of large energy companies and electric membership cooperatives, among others. SCANA Energy's ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy's operating results are sensitive to the impacts of weather on customer demand.

RESULTS OF OPERATIONS

Earnings (Loss) and dividends were as follows:

	2017	2016	2015
The Company			
Earnings (loss) per share	$ (0.83)	$ 4.16	$ 5.22
Cash dividends declared per share	$ 2.45	$ 2.30	$ 2.18
Consolidated SCE&G			
Net income (loss) (millions of dollars)	$ (171.9)	$ 525.8	$ 479.5

On February 22, 2018, SCANA declared a quarterly cash dividend on its common stock of $0.6125 per share.

2017 vs 2016

The Company's earnings (loss) per share and Consolidated SCE&G's net income (loss) primarily reflects an operating loss from Electric Operations, which includes an impairment loss associated with the abandonment of the Nuclear Project, partially offset by improved operating income from Gas Distribution. In addition, the Company's earnings (loss) per share reflects a loss resulting from enactment of the Tax Act. These and other results are discussed below.

2016 vs 2015

The Company's earnings per share and Consolidated SCE&G's net income reflects higher operating income from Electric Operations and Gas Distribution. The Company's earnings per share also reflects higher net income from Gas Marketing. These and other results are discussed below.

Matters Impacting Future Results

The Company's decision on July 31, 2017 to stop construction of Unit 2 and Unit 3 and to pursue recovery of the cost of the abandoned Nuclear Project has had and could continue to have significant impacts on the Company's and Consolidated SCE&G's future earnings, cash flows and financial position, including those related to the ultimate recovery of regulatory assets and the sustainability of tax positions. The Company continues to believe the decision to abandon the Nuclear Project was prudent and that costs incurred with respect to the project were prudent, have contested specific challenges to this decision, and believe that the issues related to the recovery of the cost of the abandoned Nuclear Project and related to the rates currently being collected under the BLRA for financing costs should be resolved in future proceedings before the SCPSC. However, based on various events following the abandonment, there is significant uncertainty as to SCE&G's ultimate ability to fully recover its costs of Unit 2 and Unit 3 and a return on them from its customers. These events include the contentious nature of ongoing reviews by legislative committees and others, legislative proposals being considered by the General Assembly and promoted by the Governor, and the Request being considered by the SCPSC that could result in the suspension of rates currently being collected under the BLRA, as well as the return of such amounts previously collected.

The Company and Consolidated SCE&G have determined that a disallowance of recovery of part of the cost of the abandoned plant is both probable and reasonably estimable under applicable accounting guidance, and have recorded a pre-tax impairment loss with respect to disallowance of unrecovered nuclear project costs and other related deferred costs totaling approximately $1.118 billion. This amount includes $210 million recorded in the third quarter of 2017 and the remaining $908 million recorded in the fourth quarter of 2017. For additional discussion, see Impairment Considerations in Critical Accounting Policies and Estimates and Note 10 to the consolidated financial statements.

It is reasonably possible that further changes in these estimates will occur in the near term and could be material; however, all such changes cannot be reasonably estimated. The above impairment loss reflects impacts similar to those that would have resulted had the proposed solution announced November 16, 2017 been implemented. If the merger benefits and cost recovery plan outlined in the Joint Petition is implemented (upon closing of the merger as contemplated in the Merger Agreement), an additional impairment loss and other charges totaling as much as approximately $1.7 billion would be expected to be recorded. If instead the Joint Petition is not approved and the Request by the ORS is approved, if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, the Company and Consolidated SCE&G may be required to record an additional impairment loss and other charges totaling as much as approximately $4.8 billion. This additional impairment loss would result from the write-off of the remaining unrecovered Nuclear Project costs of $3.976 billion recorded within regulatory assets and the refund of revised rates collections under the BLRA described above of approximately $1.9 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. The Company and Consolidated SCE&G do not currently anticipate that any of the $1.9 billion in revenue previously collected will be subject to refund; however, no assurance can be given as to the outcome of this matter.

In December 2017, the Tax Act was enacted, resulting in the remeasurement of all federal deferred income tax assets and liabilities to reflect a 21% federal statutory corporate tax rate. Due to the regulated nature of the Company's and Consolidated SCE&G's operations, the effect of this remeasurement is primarily reflected in excess deferred income tax balances within regulatory liabilities. As described in Note 2 to the consolidated financial statements, SCE&G and PSNC Energy have responded to orders from state regulators seeking information on the effects the Tax Act would have on their respective operations. The Company and Consolidated SCE&G cannot determine the amount or timing of any refunds to customers that may result. Going forward, the Company and Consolidated SCE&G expect that the lower tax expense resulting from the reduced federal statutory tax rate will result in similar reductions to amounts collected from customers through electric and gas rates, and no significant impact on financial results are expected. See also Note 5 to the consolidated financial statements for additional discussion related to deferred tax assets and deferred tax liabilities.

These matters impacting future results are further discussed under Impact of Abandonment of Nuclear Project within LIQUIDITY AND CAPITAL RESOURCES, in Note 2 and Note 10 to the consolidated financial statements and in Part I, Item 1A. Risk Factors.

Electric Operations

Electric Operations for the Company and for Consolidated SCE&G is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric Operations operating income (including transactions with affiliates) was as follows:

	The Company			**Consolidated SCE&G**		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Operating revenues	$ 2,664.4	$ 2,619.4	$ 2,557.1	$ 2,664.4	$ 2,619.4	$ 2,557.1
Fuel used in electric generation	593.6	576.1	660.6	593.6	576.1	660.6
Purchased power	80.1	63.7	52.1	80.1	63.7	52.1
Other operation and maintenance	519.0	526.1	497.1	533.4	540.2	509.6
Impairment loss	1,118.1	—	—	1,118.1	—	—
Depreciation and amortization	294.7	286.5	277.3	282.8	274.9	266.9
Other taxes	220.3	210.4	194.5	217.8	207.9	192.4
Operating Income (Loss)	$ (161.4)	$ 956.6	$ 875.5	$ (161.4)	$ 956.6	$ 875.5

Electric operations can be significantly impacted by the effects of weather. SCE&G estimates the effects on its electric business of actual temperatures in its service territory as compared to historical averages to develop an estimate of electric revenue and fuel costs attributable to the effects of abnormal weather. Results in 2017 reflect milder than normal weather in the first and fourth quarters and warmer than normal weather in the second and third quarters. Results in 2016 reflect significantly warmer than normal weather in the second and third quarters and milder than normal weather in the first and fourth quarters. Results in 2015 reflect colder than normal weather in the first quarter, warmer than normal weather in the second and third quarters and milder than normal weather in the fourth quarter.

2017 vs 2016

- Operating revenue increased due to revised rates increases under the BLRA of $57.6 million, residential and commercial growth of $29.4 million, industrial growth and higher usage of $5.5 million, increased revenue recognized under the DER program of $7.3 million and higher fuel cost recovery of $48.1 million. These revenue increases were partially offset by the effects of milder weather of $77.7 million, lower residential and commercial average use of $18.9 million and lower collections under the rate rider for pension costs of $4.0 million. The lower pension rider collections had no impact on net income as they were fully offset by the recognition, within other operation and maintenance expenses, of lower pension costs.

- Fuel used in electric generation and purchased power expenses increased due to higher fuel prices of $48.1 million, amortization of DER program costs of $3.9 million and increased sales volumes associated with residential and commercial customer growth of $5.8 million. These increases were partially offset due to lower sales volumes associated with the effects of milder weather of $15.9 million, lower residential and commercial average use of $4.1 million, lower industrial usage of $1.6 million and lower fuel handling expenses of $2.4 million.

- Other operation and maintenance expenses decreased due to lower labor costs of $24.0 million, primarily due to lower incentive compensation costs and lower pension costs associated with the lower pension rider collections, partially offset by nuclear abandonment-related severance costs of $12.3 million. This decrease was offset by higher non-labor electric generation costs of $2.2 million and due to wind down and other costs associated with the abandonment of the Nuclear Project of $10.9 million.

- Impairment loss represents the estimate of the probable disallowance of recovery associated with the abandonment of the Unit 2 and Unit 3 of $670 million, a write down to estimated fair value of the carrying value of nuclear fuel acquired for use in Unit 2 and Unit 3 of $87 million and an aggregate amount of $361 million to write off costs which had been previously deferred primarily within regulatory assets in connection with the Nuclear Project.

- Depreciation and amortization increased primarily due to net plant additions.

- Other taxes increased primarily due to higher property taxes associated with net plant additions.

2016 vs 2015

- Operating revenue increased due to revised rates increases under the BLRA of $60.7 million, residential and commercial growth of $29.0 million, industrial growth and higher usage of $9.7 million, increased revenue recognized under the DER program of $5.8 million, the effects of weather of $28.2 million and higher collections under the rate rider for pension costs of $13.5 million. The higher pension rider collections had no impact on net income as they were fully offset by the recognition, within other operation and maintenance expenses, of higher pension costs. Revenue also increased due to downward adjustments in 2015, pursuant to orders from the SCPSC, to apply $14.5 million as an offset to fuel cost recovery upon the adoption of new (lower) electric depreciation rates and by $5.2 million related to DSM Programs. These adjustments had no effect on net income in 2015 as they were fully offset by the recognition of $14.5 million of lower depreciation expense and by the recognition, within other income, of $5.2 million of gains realized upon the settlement of certain interest rate contracts. These revenue increases were partially offset by lower fuel cost recovery of $84.1 million and lower residential and commercial average use of $19.5 million.

- Fuel used in electric generation and purchased power expenses decreased due to lower fuel prices of $84.1 million, lower sales volumes associated with residential and commercial average use of $4.2 million and lower fuel handling expenses of $2.3 million. These decreases were partially offset due higher to amortization of DER program costs of $4.6 million, higher industrial usage of $1.9 million, increased sales volumes associated with residential and commercial customer growth of $6.4 million and higher sales volumes associated with the effects of weather of $4.9 million.

- Other operation and maintenance expenses increased due to higher labor costs of $25.4 million, primarily due to increased pension costs associated with the higher pension rider collections and higher incentive compensation costs. Other operation and maintenance expenses also increased due to higher amortization of DSM program costs of $2.0 million.

- Depreciation and amortization increased primarily due to net plant additions.

- Other taxes increased primarily due to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric operations above, by class, were as follows:

Classification	2017	2016	2015
Residential	7,782	8,140	7,978
Commercial	7,372	7,506	7,386
Industrial	6,212	6,265	6,201
Other	584	600	595
Total retail sales	21,950	22,511	22,160
Wholesale	916	947	942
Total Sales	22,866	23,458	23,102

2017 vs 2016

Retail and wholesale sales volumes decreased primarily due to the effects of weather, partially offset by increases associated with customer growth.

2016 vs 2015

Retail sales volumes increased primarily due to the effects of weather and customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G, and for the Company, also includes PSNC Energy. Gas Distribution operating income (including transactions with affiliates) was as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	2017	2016	2015	2017	2016	2015
Operating revenues	$ 876.0	$ 789.8	$ 811.7	$ 405.8	$ 366.8	$ 372.7
Gas purchased for resale	393.0	345.9	383.7	205.9	182.9	192.5
Other operation and maintenance	168.9	172.7	161.4	70.6	73.6	69.8
Depreciation and amortization	84.9	82.0	77.5	29.0	27.3	26.8
Other taxes	42.5	41.5	37.5	28.5	26.8	24.9
Operating Income	$ 186.7	$ 147.7	$ 151.6	$ 71.8	$ 56.2	$ 58.7

The effect of abnormal weather conditions on gas distribution margin is mitigated by the WNA at SCE&G and the CUT at PSNC Energy as further described in Revenue Recognition in Note 1 of the consolidated financial statements. The WNA and CUT do not affect sales volumes.

2017 vs 2016

- Operating revenue increased at SCE&G primarily due to increased base rates under the RSA of $6.7 million, customer growth of $11.7 million and higher gas cost recovery of $14.9 million. These increases were partially offset by lower average use of $1.6 million. In addition to these factors, operating revenue increased at the Company due to PSNC Energy's higher gas cost collections of $28.9 million, a rate increase of $14.9 million, customer growth of $8.1 million and higher CUT of $17.2 million. These increases at PSNC Energy were partially offset by milder weather and declining consumption of $18.8 million.

- Gas purchased for resale at SCE&G increased due to higher gas prices of $15.7 million and increased sales volumes associated with firm customer growth of $7.1 million. In addition to these factors, gas purchased for resale at the Company increased primarily due to PSNC Energy's higher gas costs of $28.9 million and customer growth of $2.2 million that were partially offset by milder weather and declining consumption of $7.3 million.

- Other operation and maintenance expenses decreased primarily due to lower labor costs of $4.9 million at SCE&G and $10.9 million at PSNC Energy, due primarily to lower incentive compensation costs. These decreases were partially offset by higher non-labor costs of $1.7 million at SCE&G and $8.6 million at PSNC Energy.

- Depreciation and amortization increased primarily due to net plant additions.

- Other taxes increased primarily due to higher property taxes associated with net plant additions.

2016 vs 2015

- Operating revenue decreased at SCE&G primarily due to lower gas cost recovery of $17.6 million and lower firm average use of $6.1 million. These decreases were partially offset by increased base rates under the RSA of $2.6 million and firm customer growth of $13.1 million. In addition to these factors, operating revenue decreased at the Company due to PSNC Energy's lower gas cost collections of $45.4 million. These decreases at PSNC Energy were partially offset by a rate increase of $6.5 million, increased customer growth of $10.3 million and higher CUT of $13.8 million.

- Gas purchased for resale at SCE&G decreased due to lower gas prices of $17.6 million. These decreases at SCE&G were partially offset by increased sales volumes associated with firm customer growth of $6.5 million. In addition to these factors, gas purchased for resale at the Company decreased due to PSNC Energy's decreased gas cost of $45.4 million and an excess state deferred income tax refund of $1.9 million. This decrease at PSNC Energy was partially offset by customer growth of $3.8 million, as well as higher CUT of $15.5 million.

- Other operation and maintenance expenses increased due to higher labor costs of $2.1 million at SCE&G and $6.7 million at the Company, due primarily to higher incentive compensation costs.

- Depreciation and amortization increased due to net plant additions, partially offset by the implementation of SCPSC-approved revised (lower) depreciation rates at SCE&G of $1.1 million.

- Other taxes increased primarily due to net plant additions.

Sales volumes (in MMBTU) related to gas distribution by class, including transportation, were as follows:

	The Company			Consolidated SCE&G		
Classification (in thousands)	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Residential	37,251	40,142	39,090	11,285	12,420	12,086
Commercial	28,429	29,078	28,064	12,565	12,879	12,580
Industrial	20,108	19,364	20,101	18,091	17,228	17,901
Transportation gas	51,587	49,769	49,297	6,229	5,250	4,781
Total	137,375	138,353	136,552	48,170	47,777	47,348

2017 vs 2016

Residential and commercial sales volumes decreased due to the effects of weather and lower average use. These decreases were partially offset by customer growth. Industrial sales volumes at SCE&G increased due to fewer curtailments and customer growth. Transportation volumes at SCE&G increased primarily due to firm customers transporting rather than purchasing system supply. Transportation volumes at PSNC Energy increased primarily due to firm service expansion partly offset by a decline in natural gas fired electric generation transportation and milder weather.

2016 vs 2015

Residential and commercial firm sales volumes increased primarily due to customer growth. Commercial and industrial interruptible volumes decreased, and firm volumes increased, due to customers switching from interruptible to firm service at SCE&G. Industrial volumes decreased and transportation volumes increased due to customers switching to transportation only service.

Gas Marketing

Gas Marketing is comprised of the Company’s nonregulated marketing operation, SCANA Energy, which operates in the southeast and includes Georgia’s retail natural gas market. Gas Marketing operating revenues and net income were as follows:

Millions of dollars	**2017**	**2016**	**2015**
Operating revenues	$ 1,001.4	$ 936.7	$ 1,146.7
Net Income	26.9	29.8	27.6

2017 vs 2016

Operating revenues increased primarily due to higher natural gas prices. Net income decreased primarily due to the impact of the remeasurement of deferred income taxes upon enactment of the Tax Act.

2016 vs 2015

Operating revenues decreased due to the lower market price of natural gas and lower industrial sales volume. Net income increased primarily due to a weather-related increase in demand.

Other Operating Expenses

Other operating expenses were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Other operation and maintenance	$ 736.7	$ 755.6	$ 715.3	$ 604.0	$ 613.8	$ 579.4
Impairment loss	1,118.1	—	—	1,118.1	—	—
Depreciation and amortization	381.6	370.9	357.5	311.8	302.2	293.7
Other taxes	264.2	253.9	234.2	246.4	234.7	217.3

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in their respective discussions of operating income (loss). In addition, overall increases in other operating expenses in 2016 were partially offset by the Company's sale of CGT in early 2015, which resulted in decreases in other operation and maintenance expenses of $2.2 million, depreciation and amortization of $0.7 million and other taxes of $0.5 million.

Net Periodic Pension Benefit Cost

Other operation and maintenance expense includes net periodic pension benefit cost, which was recorded on the income statements and balance sheets as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Income Statement Impact:						
Employee benefit costs	$ 15.3	$ 19.2	$ 5.3	$ 12.3	$ 16.4	$ 2.8
Other expense	0.5	0.9	1.1	0.3	0.2	0.2
Balance Sheet Impact:						
Increase in capital expenditures	5.2	5.3	3.9	4.7	4.7	3.4
Component of amount receivable from Summer Station co-owner	2.1	2.1	1.5	2.1	2.1	1.5
Increase (decrease) in regulatory assets	(0.8)	(4.6)	6.2	(0.8)	(4.6)	6.2
Net periodic benefit cost	$ 22.3	$ 22.9	$ 18.0	$ 18.6	$ 18.8	$ 14.1

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were $2.0 million for retail electric operations and $1.0 million for gas operations for each period presented. Pursuant to regulatory orders, PSNC Energy recovers current pension expense through cost of service rates.

Other Income (Expense), net

Other income (expense), net includes the results of certain incidental non-utility activities of regulated subsidiaries, the activities of certain non-regulated subsidiaries, governance activities of the parent company and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. An equity portion of AFC is included in nonoperating income and a debt portion of AFC is included in interest charges (credits), both of which have the effect of increasing reported net income. Components of other income (expense), net were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Other income	$ 78.4	$ 64.4	$ 74.5	$ 44.9	$ 29.3	$ 31.1
Other expense	(46.2)	(38.5)	(60.1)	(24.9)	(24.1)	(31.1)
Gain on sale of SCI, net of transaction costs	—	—	106.6	—	—	—
AFC - equity funds	23.2	29.4	27.0	14.8	26.1	24.8

2017 vs 2016

Other income at the Company and Consolidated SCE&G increased by $10.9 million due to the accrual of carrying costs on unrecovered nuclear project costs and by $6.3 million due to SCPSC-approved carrying cost accrual on certain deferred items. Other expenses at the Company increased primarily due to higher legal costs at the parent company. AFC decreased due to the abandonment of the Nuclear Project and a lower AFC rate as a result of removing Nuclear Project related capital costs from the average construction work in progress balance used to determine the annual AFC rate following the abandonment decision.

2016 vs 2015

Other income at the Company and Consolidated SCE&G decreased by $3.5 million due to lower gains on the sale of land and due to the recognition in 2015 of $5.2 million of gains realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to electric operating revenues and had no effect on net income (see electric margin discussion). At the Company, other income also decreased by $3.9 million and other expenses decreased by $2.3 million due to the sale of SCI, and other income and other expenses decreased by $10.5 million for billings to DECG for transition services provided at cost pursuant to the terms of the sale of CGT. Other expenses at the Company and Consolidated SCE&G decreased by $5.2 million due to lower contribution expenses. In 2015, the Company's other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC increased due to construction activity.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Interest on long-term debt, net	$ 346.7	$ 330.3	$ 311.3	$ 266.1	$ 253.8	$ 236.0
Other interest expense	16.7	12.0	6.5	21.5	16.2	12.1
Total	$ 363.4	$ 342.3	$ 317.8	$ 287.6	$ 270.0	$ 248.1

Interest expense increased in each year primarily due to increased borrowings, and in 2017 due to lower AFC on borrowed funds.

Income Taxes

At the Company, the income tax benefit for 2017 was primarily due to the impairment loss. Additionally, the impact of remeasuring deferred taxes upon enactment of the Tax Act increased deferred tax expense and resulted in additional net loss of approximately $30 million. Exclusive of these items, income tax expense increased from 2016 to 2017 primarily due to higher income before taxes. Income tax expense decreased from 2015 to 2016 primarily due to lower income before taxes. In 2015 income tax expense and income before taxes were affected by the sales of CGT and SCI. At Consolidated SCE&G, income tax expense decreased from 2016 to 2017 primarily due to impacts related to the impairment loss. Without these impacts, income tax expense increased from 2016 to 2017 primarily due to higher income before taxes. Income tax expense increased from 2015 to 2016 primarily due to higher income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Considerations

The Company and Consolidated SCE&G have experienced significant adverse events leading up to their decision to stop construction of Unit 2 and Unit 3, as well as significant adverse events since that decision was made. These events include the bankruptcy filing of the Consortium, the anticipated rejection by the Consortium of the EPC Contract with its fixed-price provisions, and the ongoing contentious proceedings before regulatory and legislative bodies, among others things described in Note 10. In addition, downgrades by credit ratings agencies have occurred since the beginning of 2017, including recent rating actions. The Company and Consolidated SCE&G have significant obligations that must be paid within the next 12 months, including long-term debt maturities and capital lease payments of $727 million for the Company (including $723 million for Consolidated SCE&G), short-term borrowings of $350 million for the Company (including $252 million for Consolidated SCE&G), interest payments of approximately $335 million for the Company (including $259 million for Consolidated SCE&G), and future minimum payments for operating leases of $34 million for the Company (including $26 million for Consolidated SCE&G). Working capital requirements, such as those for fuel supply and similar obligations, also arise due to the lag between when such amounts are paid and when related collection of such costs through customer rates occurs.

Management believes as of the date of issuance of these financial statements that it has access to available sources of cash to pay obligations when due over the next 12 months. These sources include committed lines of credit that expire in December 2018 totaling $200 million for the Company, all of which pertains to Consolidated SCE&G, and committed long-term lines of credit that expire in December 2020 totaling $1.8 billion for the Company (including $1.2 billion for Consolidated SCE&G). In addition, as of the date of issuance of these financial statements, SCE&G continues to collect in customer rates amounts previously approved under the BLRA, as well as amounts provided for in other orders related to non-BLRA electric and gas rates. However, as further described below, SCANA's credit rating has fallen below investment grade, which has constricted its ability and that of Consolidated SCE&G to issue commercial paper.

As described in Note 10, on January 31, 2018, the South Carolina House of Representatives passed a bill (H.4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Such regulatory, legislative or judicial proceedings outside of the Company’s and Consolidated SCE&G’s control may result in the temporary or permanent suspension of the approximately $445 million annually of rates being collected currently under the BLRA, the return of such amounts previously collected of $1.9 billion, or the requirement that SCE&G's share of payments received from the Toshiba Settlement ($1.095 billion) be placed in escrow or be refunded to customers. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

Were the SCPSC to grant the relief sought by ORS in the Request or grant similar relief resulting from legislative action, and as further discussed in Note 10 in the consolidated financial statements, an additional impairment loss or other charges totaling as much as approximately $4.8 billion may be required. Such an impairment loss or other charges would further stress the Company’s and Consolidated SCE&G’s equity to total capitalization ratio and may result in the Company’s and Consolidated SCE&G’s ratio of equity to total capitalization falling below minimum levels prescribed in the Company’s credit agreements. In such an event, the Company’s and Consolidated SCE&G’s ability to borrow under their commercial paper programs and credit facilities and their ability to pay future dividends would likely be limited or may trigger events of default under such agreements.

Known and knowable conditions and events when considered in the aggregate as of the date of issuance of these financial statements do not suggest it is probable that the Company and Consolidated SCE&G will not be able to meet obligations as they come due over the next 12 months. However, possible future actions related to rates or refunds could have a material adverse effect on the Company’s and Consolidated SCE&G’s financial condition, liquidity, results of operations and cash flows such that management’s conclusion with respect to its ability to pay obligations when due could change.

Impact of Abandonment of Nuclear Project

Toshiba provided a parental guaranty for WEC’s payment obligations under the EPC Contract. Following the bankruptcy of WEC, the Toshiba Settlement was executed under which Toshiba was to make periodic settlement payments in the total amount of approximately $2.2 billion ($1.2 billion for SCE&G's 55% share), including certain amounts with respect to contractor liens. In 2017, the first payment under the Toshiba Settlement was received and the remaining amounts due were monetized, resulting in total cash inflows of approximately $2 billion (approximately $1.1 billion for SCE&G's 55% share), including amounts related to the contractor liens. See also Note 10 to the consolidated financial statements. Portions of these proceeds have been utilized to repay maturing commercial paper balances. Such short-term borrowings had been incurred primarily for the construction of Unit 2 and Unit 3 prior to the decision to stop their construction.

Regulatory proceedings being considered by the SCPSC include the Request filed by the ORS which, if granted, would require SCE&G to (1) immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA, and (2) make credits to future bills or refunds to customers for prior revised rates collections in the event that the BLRA is found to be unconstitutional or the South Carolina General Assembly amends or revokes it. SCE&G estimates that revised rates collections, including collections related to transmission assets expected to be placed into service, currently total approximately $445 million annually, and such amounts accumulated as of December 31, 2017 total approximately $1.9 billion.

In an amendment to the Request, the ORS has asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. Parties who filed to intervene in these proceedings or who filed a letter in support of the Request, as amended, include the Governor, the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, the SCEUC, certain large industrial customers, and several environmental groups. On December 20, 2017, the SCPSC denied SCE&G's motion to dismiss the Request and requested that the ORS carry out an inspection, audit and examination of SCE&G's revenue requirements to assist the SCPSC in determining whether SCE&G's present schedule of rates is fair and reasonable and also ordered that a hearing be scheduled to consider the Request. The hearing has not yet been scheduled. See Note 2 for additional developments. SCE&G intends to continue vigorously contesting the Request, but cannot give any assurance as to the timing or outcome of this matter. Any adverse action by the SCPSC, such as that sought by the ORS in the Request, could have a material adverse impact on the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

Should the SCPSC or a court direct that proceeds arising from the Toshiba Settlement be refunded to customers in the near-term, or direct that such funds be escrowed or otherwise made unavailable to SCE&G, it is anticipated that SCE&G would reissue commercial paper, draw on its credit facilities or issue long-term debt to fund such requirement if such sources are available. However, were the SCPSC to rule in favor of the ORS in response to the Request that SCE&G suspend collections from customers of amounts previously authorized under the BLRA, or were other actions of the SCPSC or others taken in order to significantly restrict SCE&G’s access to revenues or impose additional adverse refund obligations on SCE&G, the Company’s and Consolidated SCE&G's assessments regarding the recoverability of all or a portion of the remaining balance of unrecovered nuclear project costs (see Note 2 to the consolidated financial statements) would be adversely impacted and additional impairment losses would likely be recorded. Further, the recognition of significant additional impairment losses with respect to unrecovered Nuclear Project costs could increase the Company’s and Consolidated SCE&G’s debt to total capitalization to a level which may limit their ability to borrow under their commercial paper programs or under their credit facilities and also could constitute a default under these credit facilities. Borrowing costs for long-term debt issuances and access to capital markets could also be negatively impacted.

For additional background on the Nuclear Project and further details on the matters described above, see Note 10 to the consolidated financial statements under Abandoned Nuclear Project - Toshiba Settlement and Subsequent Monetization and Determination to Stop Construction and Related Regulatory, Political and Legal Developments.

In the first quarter of 2017, credit ratings agencies placed SCANA and SCE&G’s credit ratings on negative outlook or watch status due to adverse developments relating to the WEC Bankruptcy. In the third quarter of 2017, two agencies lowered their ratings for SCANA and its rated subsidiaries, citing a decline in the regulatory environment as a principal reason for the downgrades, and both agencies maintained their negative outlook or watch status. On January 3, 2018, after SCANA announced a proposed merger with Dominion Energy, each of the three agencies affirmed or reported no change to their respective credit ratings, and one agency revised its rating outlook for SCANA and its rated operating companies from negative to evolving. However, on January 31, 2018, the South Carolina House of Representatives overwhelmingly approved a bill (H.4375) that, if enacted, would temporarily repeal rates SCE&G collects under the BLRA. As a result, on February 5, 2018, one agency downgraded its ratings for SCANA and SCE&G, and attributed the downgrade to the action taken by the House of Representatives and the politically charged environment that is expected to weigh heavily on any decisions by the SCPSC related to SCE&G's electric rates. With this recent downgrade, the issuer ratings and the senior unsecured debt ratings for SCANA are considered below investment grade by two credit agencies; the issuer ratings for SCE&G are considered to be at the threshold for investment grade by two credit agencies while its senior secured debt ratings remain above investment grade; and the issuer ratings for PSNC Energy are considered to be at the threshold for investment grade by one credit agency while its senior secured debt ratings remain above investment grade. All of the ratings for SCANA, SCE&G and PSNC Energy are either under review for possible downgrade or have a negative or evolving outlook.

Any actions taken by or anticipated to be taken by regulators or legislators that are viewed as adverse, including a change to the BLRA or a requirement that SCE&G make credits to future bills or refunds to customers above such amounts as are included in the Merger Agreement or any requirement that SCE&G make such credits or refunds in the absence of the merger being consummated, or deterioration of the rated companies' commonly monitored financial credit metrics or any additional adverse developments with respect to the Nuclear Project, could further negatively affect their debt ratings. If these rating agencies were to further lower any of these ratings, borrowing costs on new issuances of long-term debt and commercial paper would increase, which could adversely impact financial results or limit or eliminate refinancing opportunities, and the potential pool of investors and funding sources could decrease. In addition, further ratings downgrades may result in lower collateral thresholds being applied to the Company's and Consolidated SCE&G's commodity derivatives, or the removal of such thresholds altogether. This action would have the effect of requiring the Company to post additional collateral for commodity derivative instruments with unfavorable fair values. Ratings downgrades have also resulted in prepayments and demands from vendors for letters of credit, cash deposits, or other forms of credit support under certain gas supply and other agreements, and further ratings downgrades could result in requirements for additional deposits or the provision of additional credit support in order to conduct business under these agreements. See further discussion under the heading Credit Risk Considerations in Note 6 to the consolidated financial statements.

Significant Tax Deductions and Credits

The Company and Consolidated SCE&G have claimed significant research and experimentation tax deductions and credits related to the design and construction activities of Unit 2 and Unit 3. A significant portion of these claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. (See also Note 5 to the consolidated financial statements.) The Company and Consolidated SCE&G also expect to claim a significant tax deduction related to the decision to stop construction and to abandon the Nuclear Project in 2017.

These tax claims primarily involve the timing of recognition of tax deductions rather than permanent tax attributes, and their permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to them, had been deferred within regulatory assets. As such, until December 31, 2017 when it was determined to treat these deferrals as impaired (see Note 10 to the consolidated financial statements), these claims had not had, and were not expected to have in the future, significant direct effects on the Company's and Consolidated SCE&G's results of operations. Nonetheless, the claims have contributed significantly to the Company's and Consolidated SCE&G's cash flows by providing a significant source of capital and lessening the level of debt and equity financing that the Company and Consolidated SCE&G have needed to raise in the financial markets.

The claims made to date are under examination, and are considered controversial, by the IRS. Tax deductions which are expected to be claimed in connection with the determination to abandon the construction of Unit 2 and Unit 3 may also be considered controversial; therefore, it is also expected that the IRS will examine future tax returns. To the extent that any of these claims are not sustained as ordinary losses on examination or through any subsequent appeal, the Company and Consolidated SCE&G will be required to repay any cash received for tax benefit claims which are ultimately disallowed, along with interest on those amounts. Such amounts could be significant and could adversely affect the Company's and Consolidated SCE&G's liquidity, cash flows, results of operations and financial condition. In certain circumstances, which management considers to be remote, penalties for underpayment of income taxes could also be assessed. Additionally, in such circumstances, the Company and Consolidated SCE&G may need to access the capital markets to fund those tax and interest payments, which could in turn adversely impact their ability to access financial markets for other purposes.

Other Liquidity Requirements and Restrictions

The terms of the Merger Agreement place limits on the Company and its subsidiaries as to certain investing and financing transactions. While the Merger Agreement permits the Company and its subsidiaries to refinance and issue certain long-term debt, make capital expenditures at certain levels, consummate certain planned investments, and make regular quarterly dividend payments to its shareholders at certain levels, transactions above these levels would require consent from Dominion Energy, which consent cannot be unreasonably withheld. Permitted transactions include, but are not limited to, the planned refinancing of $710 million of long-term debt maturing in 2018 at Consolidated SCE&G and the planned new issuance of $100 million of long-term debt at PSNC Energy, the purchase of an existing 540-MW gas fired power plant, and the payment by SCANA of regular quarterly dividends to its shareholders subject to certain limits. See Capital Expenditures herein for additional restrictions. In addition, SCANA's Supplementary Key Executive Severance Benefits Plan provides certain payments to qualified senior executive officers in connection with a change in control. In January 2018, approximately $110.7 million was placed irrevocably in a rabbi trust to fund payments pursuant to this and certain other deferred compensation, incentive and retirement plans, which might arise in connection with a change in control and/or a termination of employment or service if and when such payments become due.

The Company expects to meet contractual cash obligations in 2018 through internally generated funds and additional short- and long-term borrowings. Subject to the outcome of the regulatory, legislative and legal proceedings discussed above, the Company expects that, barring a future impairment of the capital markets or its access to such markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for refinancing maturing long-term debt. As noted above, adverse developments in regulatory, legislative or legal proceedings could alter these conclusions.

The terms of the Merger Agreement limit the dividends that SCANA can pay on its shares of common stock to an amount not greater than $0.6125 per share for any quarter. In order to preserve liquidity, the Company may revise its dividend policy to reduce or eliminate dividend payments. Such a decision could result in a significant decrease in the price of SCANA's common stock and an increase in the cost of raising equity capital.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including the legislative and regulatory environment, capital structure and the ability to meet liquidity requirements. As previously noted, adverse developments with respect to recovery of Nuclear Project costs have negatively affected the Company's and Consolidated SCE&G's debt ratings. Further adverse developments, changes in the legislative and regulatory environment or deterioration of SCANA's or its rated operating companies' commonly monitored financial credit metrics could cause the Company and Consolidated SCE&G to pay higher interest rates on its long- and short-term indebtedness, could limit the Company's and Consolidated SCE&G's access to capital markets and liquidity, and could trigger more stringent collateral requirements on interest rate and commodity hedges and under gas supply agreements and other contracts.

Cash provided from operating activities in 2016 and 2017 reflect significant tax benefits (reductions in income tax payments) arising from the deductions previously described under Significant Tax Deductions and Credits. The Company's decision in 2017 to stop construction of Unit 2 and Unit 3 and to abandon the Nuclear Project is expected to result in a significant tax deduction and an associated NOL for tax purposes. The Company expects to obtain a refund of taxes paid in certain prior years as a result of the carryback of the NOL, and expects to benefit from the carryforward of the NOL in future years. These cash flows are expected to supplant portions of financing which would otherwise be obtained in the capital markets.

Enactment of the Tax Act resulted in the remeasurement of deferred income tax assets and liabilities and the recognition as regulatory liabilities of certain excess deferred income taxes (see Note 2 and Note 5 to the consolidated financial statements). These regulatory liabilities will be amortized to the benefit of customers in accordance with the normalization provisions of the IRC and Code of Federal Regulations, which will serve to mitigate significant negative cash impact. Similarly, since the majority of the Company's and Consolidated SCE&G's businesses are rate regulated, lower income taxes payable in future years due to the Tax Act should ultimately result in lower collections from customers in rates.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.2 billion in 2017. Estimates of capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2018	2019
SCE&G		
Generation	$ 124	$ 145
Transmission & Distribution	229	203
Other	12	23
Gas	98	105
Common	3	11
Total SCE&G	466	487
PSNC Energy	288	275
Other	37	24
Total Normal	791	786
Nuclear Fuel - SCE&G	54	51
Total Estimated Capital Expenditures	$ 845	$ 837

Under the terms of the Merger Agreement, the Company may increase the amounts of the above estimated capital expenditures in 2018 and 2019 by not more than 10% without obtaining the consent of Dominion Energy.

Contractual cash obligations as of December 31, 2017 are summarized as follows:

Contractual Cash Obligations

	Payments due by periods				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long- and short-term debt, including interest	$ 13,352	$ 1,406	$ 1,721	$ 768	$ 9,457
Capital leases	28	5	14	3	6
Operating leases	112	34	42	9	27
Purchase obligations	3,159	2,345	812	2	—
Other commercial commitments	2,929	1,057	846	258	768
Total	$ 19,580	$ 4,847	$ 3,435	$ 1,040	$ 10,258

As of December 31, 2017, the SCPSC has taken no final action with regard to the Request by the ORS or in connection with the effect of the Tax Act on customer rates, including any action with respect to excess deferred income taxes. Therefore, no amounts have been included in the table above for these matters. See Note 2 to the consolidated financial statements.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty. Purchase obligations also includes amounts related to the EPC Contract, which the Company anticipates that WEC and WECTEC will reject. The Company does not expect that such amounts will be expended. See Note 10 to the consolidated financial statements.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases. The Company has included certain amounts related to nuclear fuel commitments based on its interpretation of its obligations under existing contract terms that are currently disputed by the supplier.

Unrecognized tax benefits of approximately $19 million have been excluded from the table above due to uncertainty as to the timing of any future payments. In addition, the table excludes amounts that may be required to be paid to federal or state taxing authorities related to tax deductions and credits on tax returns for which examinations have not been completed or closed. For additional information, see Note 5 to the consolidated financial statements.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $12.5 million in 2017, and such annual payments are expected to be the same or increase to as much as $16.5 million in the future.

The Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. The Company, including Consolidated SCE&G, is also party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash collateral. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated for accounting purposes as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 6 to the consolidated financial statements. As of December 31, 2017, the Company had posted approximately $29 million in cash collateral related to interest rate derivative contracts.

The Company has a legal obligation associated with the decommissioning and dismantling of Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements. SCE&G's method for funding decommissioning costs is described in Note 1 to the consolidated financial statements.

Financing Limits and Related Matters

Issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018. Were adverse developments to occur with respect to uncertainties highlighted elsewhere, the ability of SCE&G or GENCO to secure renewal of this short-term borrowing authority may be adversely impacted.

At December 31, 2017 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $400 million, $1.2 billion, of which $500 million relates to Fuel Company, and $200 million, respectively, which expire in December 2020. In addition, at December 31, 2017 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2017, the Company had no outstanding borrowings under its credit facilities, had approximately $350 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC-supported letters of credit, and held approximately $409 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. The Company's average short-term borrowings outstanding during 2017 were approximately $870 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2017, the Company’s long-term debt portfolio has a weighted average maturity of approximately 19 years and bears an average cost of 5.75%. Substantially all long-term debt bears fixed interest rates or is swapped to fixed.

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, the terms of the Merger Agreement limit the dividends that SCANA can pay on its shares of common stock to an amount not greater than $0.6125 per share for any quarter.

SCE&G’s bond indenture (relating to the hereinafter defined Bonds) contains provisions that could limit the payment of cash dividends on its common stock. SCE&G's bond indenture permits the payment of dividends on SCE&G's common stock only either (1) out of its Surplus (which as defined equates to its retained earnings) or (2) in case there is no Surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, the Federal

Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2017, approximately $94.0 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

PSNC Energy's note purchase and debenture purchase agreements contain provisions that could limit the payment of cash distributions, including dividends, on PSNC Energy's common stock. These agreements generally limit the sum of distributions to an amount that does not exceed $30 million *plus* 85% of Consolidated Net Income (as therein defined) accumulated after December 31, 2008 *plus* the net proceeds of issuances by PSNC Energy of equity or convertible debt securities (as therein defined). As of December 31, 2017, this limitation would permit PSNC Energy to pay cash distributions in excess of $100 million.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. At December 31, 2017, SCE&G's Unfunded Net Property Additions (which are based on property certified November 30, 2017) totaled approximately $754 million, and the aggregate principal of retired Bonds totaled approximately $491 million. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be issued (Bond Ratio). For the year ended December 31, 2017, the Bond Ratio was 5.24. Adjusted Net Earnings, as therein defined, excludes the impairment loss.

Financing Activities

During 2017, net cash outflows related to financing activities totaled approximately $802 million, primarily associated with short-term borrowings and the payment of dividends. During 2016, net cash inflows related to financing activities totaled approximately $560 million, primarily associated with the proceeds from the issuance of long-term debt and short-term borrowings, partially offset by the payment of dividends.

On November 1, 2016, Consolidated SCE&G paid at maturity $100 million related to a nuclear fuel financing which had an imputed interest rate of 0.78%.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. Also in June 2016, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of the $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2017, PSNC Energy issued $150 million of 4.18% senior notes due June 22, 2047. In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from these sales were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $39 million in 2017, $113 million in 2016, and $253 million, net, in 2015.

For additional information, see Note 4 to the consolidated financial statements.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2017, were as follows:

December 31,	2017	2016	2015	2014	2013
The Company	0.43	3.38	4.40	3.39	3.22
Consolidated SCE&G	(0.10)	3.66	3.69	3.77	3.48

The earnings deficiency below fixed charges for 2017 is approximately $226 million for the Company and approximately $338 million for Consolidated SCE&G. Ratios for 2017 reflect impairment losses related to the Nuclear Project. See Note 10 to the consolidated financial statements. The Company's ratio for 2015 reflects the impact of gains recorded upon the sale of certain subsidiaries. See Note 1 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

The operations of the Company are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on financial condition, results of operations and cash flows. In addition, the conditions or requirements that will be imposed by regulatory or legislative proposals often cannot be predicted. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, recovery of such expenditures and costs are expected through existing ratemaking provisions.

For the three years ended December 31, 2017, capital expenditures for environmental control equipment at fossil fuel generating stations totaled $60.7 million. During this same period, expenditures were made for the construction and retirement of landfills and ash ponds, net of disposal proceeds, of approximately $23.6 million. In addition, expenditures were made to operate and maintain environmental control equipment at fossil plants of $8.2 million in 2017, $9.5 million in 2016 and $8.7 million in 2015, which are included in other operation and maintenance expense, and expenditures were made to handle waste ash, net of disposal proceeds, of $1.2 million in 2017, $2.4 million in 2016 and $1.3 million in 2015, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2017, 2016 and 2015 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $28 million for 2018 and $329 million for the four-year period 2019-2022. These expenditures are included in the Estimated Capital Expenditures table, discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the New Source Review provisions and the NSPS of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to the Company's electric and gas systems, as well as impacts on employees and customers, the supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow for the protection of assets and the return of systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted below. In addition, see Environmental Matters above for a discussion of related regulations to which the Company's operations are subject.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC, under Dodd-Frank, concerning record keeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCANA and any of its subsidiaries engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and other matters, including accounting; the DOE under the Federal Power Act as to use of emergency authority and coordination of all applicable federal authorizations and related environmental reviews to site an electric transmission facility; and the NRC with respect to the ownership, construction, operation and decommissioning of its nuclear facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings); the FERC as to issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters; and the DOE under the Federal Power Act as to use of emergency authority.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.
SCE&G and PSNC Energy	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively. The ORS and the NCUC as to enforcement of federal and state pipeline safety requirements in South Carolina (SCE&G) and North Carolina (PSNC Energy), respectively. The FERC as to participation in wholesale natural gas markets.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract. The FERC as to participation in wholesale natural gas markets.

Material retail rate proceedings, and significant uncertainties with respect to certain of these proceedings, are described in Note 2 and Note 10 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system and certain facilities related to generation and distribution are subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and the CFTC and the SEC continue to modify the implementation of Dodd-Frank through rule makings. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Impairment Considerations

Under the current regulatory construct in South Carolina, pursuant to the BLRA or through other means, the ability of SCE&G to recover costs incurred in connection with Unit 2 and Unit 3, and a reasonable return on them, will be subject to review and approval by the SCPSC. In light of the contentious nature of the reviews by legislative committees and others, the adverse impact that would result if proposed legislation is enacted, and the Request being considered by the SCPSC that could result in the suspension of rates currently being collected under the BLRA, as well as the return of such amounts previously collected, there is significant uncertainty as to SCE&G’s ultimate ability to fully recover its costs of Unit 2 and Unit 3 and a return on them from its customers. SCE&G continues to contest the specific challenges set forth in regulatory, legislative and legal proceedings (see also Note 10 to the consolidated financial statements). However, based on the consideration of those challenges, and particularly in light of SCE&G's proposed solution announced on November 16, 2017 and details in the Joint Petition filed by SCE&G and Dominion Energy with the SCPSC on January 12, 2018, the Company and Consolidated SCE&G have determined that a disallowance of recovery of part of the cost of the abandoned plant is both probable and reasonably estimable under applicable accounting guidance. In addition, the Company and Consolidated SCE&G have determined that recovery of certain other related costs deferred within regulatory assets is less than probable. As a result, as of December 31, 2017, the Company and Consolidated SCE&G have recognized a pre-tax impairment loss totaling $1.118 billion ($690 million net of tax). With the exception of the $210 million loss recorded in the third quarter of 2017 as explained below, this impairment loss was recorded in the fourth quarter of 2017. A discussion of this impairment loss follows:

- A pre-tax impairment loss was recorded with respect to disallowance of unrecovered nuclear project costs of approximately $670 million. This amount includes $210 million recorded in the third quarter of 2017, which represented costs of approximately $1.2 billion that had been expended on the project, exclusive of transmission costs, but which had not yet been determined to be prudent by the SCPSC in connection with revised rates proceedings under the BLRA, offset by the amount of approximately $1 billion, which amount represents the recovery of the Toshiba Settlement proceeds that are in excess of amounts from that settlement that the Company and Consolidated SCE&G estimated may be necessary to satisfy certain project liens. This impairment loss also includes $180 million, which amount arises from SCE&G’s entry into an agreement in the fourth quarter of 2017 to purchase in 2018 an existing 540-MW combined cycle gas generating station along with SCE&G's commitment to regulators and the public that the recovery of the initial capital investment in the facility would not be sought from customers. The remaining $280 million of this impairment loss was recorded after consideration of the regulatory and political developments in the fourth quarter of 2017 and early 2018 described in Note 10 to the consolidated financial statements.
- A pre-tax impairment loss was recorded in the aggregate amount of $361 million to write off costs which had been previously deferred, primarily as regulatory assets, in connection with the Nuclear Project. Such regulatory assets included deferred losses on interest rate swaps for which debt will not be issued due to the abandonment of the Nuclear Project, carrying costs on deferred tax assets arising from the capitalization of interest costs for tax purposes, net deferred costs and tax benefits related to foregone domestic production activities deductions (net of uncertain tax positions and credits) taken with respect to the project, and taxes associated with equity AFC.
- Finally, an $87 million pre-tax impairment loss was recorded in order to reduce to estimated fair value the carrying value of nuclear fuel acquired for use in Unit 2 and Unit 3.

With the exception of the $87 million related to nuclear fuel, the above impairment loss reflects impacts similar to those that may have resulted had the proposed solution announced November 16, 2017 been implemented. That proposal is presented by SCE&G as a less-favored alternative to the merger benefits and cost recovery plan in the January 12, 2018 Joint Petition. It is reasonably possible that a change in the estimated impairment loss could occur in the near term. If the merger benefits and cost recovery plan outlined in the Joint Petition is implemented (upon closing of the merger as contemplated in the Merger Agreement), an additional impairment loss and other charges totaling as much as approximately $1.7 billion would be expected to be recorded. This additional impairment loss would result from the write-off of unrecovered Nuclear Project costs of approximately $856 million recorded within regulatory assets and the recording of additional liabilities for customer refunds totaling approximately $1.875 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. If instead the Joint Petition is not approved and the Request by the ORS is approved, and if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, the Company and Consolidated SCE&G may be required to record an additional impairment loss and other charges totaling as much as approximately $4.8 billion. This additional impairment loss would result from the write-off of the remaining unrecovered Nuclear Project costs of $3.976 billion recorded within regulatory assets and the refund of revised rates collections under the BLRA described above of approximately $1.9 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens.

Accounting for Rate Regulated Operations

Regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the criteria of accounting for rate-regulated utilities may no longer be met, and the write off of regulatory assets and liabilities could be required. Such an event could have a material effect on the results of operations, liquidity or financial position of the Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the regulatory assets and liabilities.

Generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write down in those assets could be required. It is not possible to predict whether any write-downs would be necessary and, if they were, the extent to which they would affect results of operations in the period in which they would be recorded. As of December 31, 2017, net investments in fossil/hydro and nuclear generation assets (excluding assets associated with the Nuclear Project, which are discussed under Impairment Considerations above) were approximately $2.2 billion and $825 million, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, estimates are recorded for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. The Company's accounts receivable included unbilled revenues of $220.9 million at December 31, 2017 and $178.9 million at December 31, 2016, compared to total revenues of $4.4 billion in 2017 and $4.2 billion in 2016. See Note 1 to the consolidated financial statements for a discussion of the impact expected from the adoption of new revenue recognition guidance in 2018.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G’s accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates, less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The asset balance held in the trust reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Asset Retirement Obligations

AROs are accrued for legal obligations associated with the retirement of long-lived tangible assets that result from acquisition, construction, development and normal operation in accordance with applicable accounting guidance. These obligations are recognized at present value in the period in which they are incurred, and associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2017, the Company has recorded AROs of $208 million for nuclear plant decommissioning (as discussed above) and AROs of $360 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of precision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as a liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $22.3 million recorded in 2017 reflects the use of a 4.22% discount rate derived using a cash flow matching technique, and an assumed 7.25% long-term rate of return on plan assets. The Company believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2017 would have increased the Company’s pension cost by $1.7 million and increased the pension obligation by $25.2 million. Further, had the assumed long-term rate of return on assets been 7.00%, the Company’s pension cost for 2017 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2017, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.1%, 5.4%, 6.9% and 8.2%, respectively. The 2017 expected long-term rate of return of 7.25% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2018, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.1%, 7.8%, 6.6% and 8.5%, respectively. For 2018, it is anticipated that the long-term expected rate of return will be 7.00%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's and PSNC Energy's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after 2023. As a result, the significance of pension costs and the criticality of the related estimates will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future based on current market conditions and assumptions.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.30%, derived using a cash flow matching technique, and recorded a net cost for 2017 of $17.0 million. Had the selected discount rate been 4.05% (25 basis points lower than the discount rate referenced above), the expense for 2017 would have been $0.6 million higher and the obligation would have increased by $8.6 million. Because the plan provisions include “caps” on company per capita costs, and because employees hired after 2010 are responsible for the full cost of retiree medical benefits elected by them, health care cost inflation rate assumptions do not materially impact the net expense recorded.

Uncertain Income Tax Positions

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In 2016 and 2017, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the design and construction activities of the Nuclear Project, in its 2015 and 2016 income tax returns. SCANA expects to claim similar deductions and credits on its 2017 tax return when it is filed in 2018. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. See also Note 5 to the consolidated financial statements.

These IRC Section 174 income tax deductions and IRC Section 41 credits were considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities were recorded as unrecognized tax benefits in the financial statements. Following the abandonment of the Nuclear Project, SCANA anticipates that an abandonment loss deduction under IRC Section 165 will be claimed on the 2017 tax return. As such, certain of the IRC Section 174 deductions, to the extent they are denied, would instead be deductible in 2017 under IRC Section 165. The abandonment loss deduction is also considered an uncertain tax position; however, under relevant accounting guidance, no such estimated unrecognized tax benefits were recorded as of December 31, 2017. The remaining unrecognized tax benefits include the impact of the IRC Section 174 deductions on domestic production activities deductions, credits, and certain unrecognized state tax benefits.

As of December 31, 2017, the Company and Consolidated SCE&G have recorded an unrecognized tax benefit of $98 million ($19 million net of the impact of state deductions on federal returns, net of NOLs and credit carryforwards, and net of receivables related to the uncertain tax positions). If recognized, $98 million of the tax benefit would affect the Company's and Consolidated SCE&G's effective tax rates. These unrecognized tax benefits are not expected to increase significantly within the next 12 months. It is also reasonably possible that these unrecognized tax benefits may decrease by $11 million within the next 12 months. No other material changes in the status of the Company's or Consolidated SCE&G's tax positions have occurred through December 31, 2017.

The estimates of unrecognized tax benefits were computed with consideration as to whether the claims are (or are not) more likely than not to be sustained and with consideration of analyses of cumulative probabilities regarding potential outcomes. Such estimates involve significant management judgment and varying levels of precision. Changes in such estimates are required to be recorded as circumstances change and additional information regarding the claims and potential outcomes becomes available, and these changes could be significant.

Historically, because the unrecognized tax benefit through December 31, 2017 primarily involved the timing of recognition of tax deductions rather than permanent tax attributes, the estimates regarding their recognition did not have a significant impact on the Company's effective tax rate. Further, until December 31, 2017, when such deferrals were considered to be less than probable of recovery (see Note 10), these permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to the unrecognized tax benefits, had been deferred within regulatory assets. As such, the impacts of these significant accounting estimates, and changes therein, had primarily been reflected on the balance sheet rather than in results of operations. In the future, the impact of changes in estimates with respect to these permanent attributes (net) are not expected to be deferred within regulatory assets (see Note 10) and the impact of such changes to the unrecognized tax benefit related to these permanent attributes (net) could be significant.

Upon resolution of the uncertainties, the Company will be required to re-pay any tax benefits claimed which are ultimately disallowed, along with interest on those amounts. In certain circumstances, which the Company considers to be remote, penalties for underpayment of income taxes could also be assessed. Such re-payment amounts could be significant and adversely affect cash flow and financial condition.

OTHER MATTERS

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. The Company does not engage in significant off-balance sheet financing or similar transactions, although it is party to various operating leases in the normal course of business for land, office space, furniture, equipment, rail cars, a purchase power agreement, and airplanes.

Claims and Litigation

For a description of claims and litigation, see Note 10 to the consolidated financial statements.

Other

As Georgia's regulated provider, SCANA Energy provides service to customers considered to be low-income or that are otherwise unable to obtain natural gas service from other marketers. SCANA Energy provides this service at rates approved by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA's natural gas distribution and gas marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating natural gas commodity prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or placed under contract.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provide information about long-term debt issued by the Company and Consolidated SCE&G and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

The Company

December 31, 2017	**Expected Maturity Date**							
Millions of dollars	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	722.5	12.0	361.5	490.2	259.3	4,683.9	6,529.4	7,261.8
Average Fixed Interest Rate (%)	6.01	4.31	6.31	4.63	5.26	5.71	5.68	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	120.6	142.6	137.8
Average Variable Interest Rate (%)	2.18	2.18	2.18	2.18	2.18	1.64	1.72	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	554.4	4.4	4.4	4.4	4.4	124.2	696.2	20.4
Average Pay Interest Rate (%)	2.14	6.17	6.17	6.17	6.17	4.51	2.66	—
Average Receive Interest Rate (%)	1.48	2.18	2.18	2.18	2.18	1.91	1.58	—

December 31, 2016	**Expected Maturity Date**							
Millions of dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	12.5	721.7	11.1	360.2	489.0	4,789.7	6,384.3	7,040.6
Average Fixed Interest Rate (%)	4.21	6.01	4.40	6.33	4.64	5.73	5.70	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	125.0	147.0	142.7
Average Variable Interest Rate (%)	1.63	1.63	1.63	1.63	1.63	1.16	1.23	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	554.4	704.4	4.4	4.4	4.4	128.6	1,400.6	12.3
Average Pay Interest Rate (%)	2.91	2.22	6.17	6.17	6.17	4.57	2.74	—
Average Receive Interest Rate (%)	1.00	1.00	1.63	1.63	1.63	1.08	1.02	—

Consolidated SCE&G

December 31, 2017	Expected Maturity Date							
Millions of dollars	2018	2019	2020	2021	2022	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	722.5	12.0	11.5	40.2	9.3	4,333.9	5,129.4	5,726.8
Average Fixed Interest Rate (%)	6.01	4.31	4.38	3.58	4.74	5.76	5.77	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	63.5
Average Variable Interest Rate (%)	—	—	—	—	—	1.21	1.21	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	550.0	—	—	—	—	71.4	621.4	37.4
Average Pay Interest Rate (%)	2.10	—	—	—	—	3.29	2.24	—
Average Receive Interest Rate (%)	1.48	—	—	—	—	1.71	1.51	—

December 31, 2016	Expected Maturity Date							
Millions of dollars	2017	2018	2019	2020	2021	Thereafte	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	12.0	721.7	11.1	10.2	39.0	4,339.7	5,133.7	5,687.3
Average Fixed Interest Rate (%)	4.27	6.01	4.40	4.54	3.60	5.75	5.76	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	64.9
Average Variable Interest Rate (%)	—	—	—	—	—	0.76	0.76	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	550.0	700.0	—	—	—	71.4	1,321.4	31.7
Average Pay Interest Rate (%)	2.88	2.19	—	—	—	3.29	2.54	—
Average Receive Interest Rate (%)	1.00	1.00	—	—	—	0.64	0.98	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of long-term debt and interest rate derivatives, see the Liquidity and Capital Resources section in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 4 and Note 6 to the consolidated financial statements.

Commodity Price Risk

The following table provides information about the Company's financial instruments, which are limited to financial positions of Energy Marketing and PSNC Energy, that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	2018	2019	2020
Futures - Long			
Settlement Price (a)	2.87	2.94	—
Contract Amount (b)	53.1	13.3	—
Fair Value (b)	49.8	13.0	—
Futures - Short			
Settlement Price (a)	2.85	—	—
Contract Amount (b)	5.6	—	—
Fair Value (b)	5.1	—	—
Options - Purchased Call (Long)			
Strike Price (a)	3.35	—	—
Contract Amount (b)	20.7	—	—
Fair Value (b)	0.7	—	—
Swaps - Commodity			
Pay fixed/receive variable (b)	15.9	6.7	3.0
Average pay rate (a)	3.2293	2.9298	2.8730
Average received rate (a)	2.8587	2.8613	2.8211
Fair Value (b)	14.1	6.5	2.9

Pay variable/receive fixed (b)	29.6	11.5	2.7
Average pay rate (a)	2.8505	2.8710	2.8211
Average received rate (a)	3.0993	2.9410	2.8764
Fair Value (b)	32.2	11.8	2.8
Swaps - Basis			
Pay variable/receive variable (b)	7.0	0.3	—
Average pay rate (a)	2.8191	3.0876	—
Average received rate (a)	2.7935	3.0306	—
Fair Value (b)	7.0	0.3	—

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), changes in common equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedule listed in the Part IV at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Emphasis of Matter

As discussed in Note 10 to the financial statements, the abandoned Nuclear Project has led to legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

We have served as the Company's auditor since 1945.

SCANA Corporation and Subsidiaries
Consolidated Balance Sheets

December 31, (Millions of dollars)	2017	2016
Assets		
Utility Plant In Service	$ 14,370	$ 13,444
Accumulated Depreciation and Amortization	(4,611)	(4,446)
Construction Work in Progress	471	4,845
Nuclear Fuel, Net of Accumulated Amortization	208	271
Goodwill	210	210
Utility Plant, Net	10,648	14,324
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $133 and $138	270	276
Assets held in trust, net-nuclear decommissioning	136	123
Other investments	68	76
Nonutility Property and Investments, Net	474	475
Current Assets:		
Cash and cash equivalents	409	208
Receivables:		
Customer, net of allowance for uncollectible accounts of $6 and $6	665	616
Income taxes	198	142
Other	105	127
Inventories:		
Fuel	143	136
Materials and supplies	161	155
Prepayments	99	105
Other current assets	17	17
Derivative financial instruments	54	—
Total Current Assets	1,851	1,506
Deferred Debits and Other Assets:		
Regulatory assets	5,580	2,130
Other	186	272
Total Deferred Debits and Other Assets	5,766	2,402
Total	$ 18,739	$ 18,707

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2017	2016
Capitalization and Liabilities		
Common Stock - no par value, 143 million shares outstanding for all periods presented	$ 2,390	$ 2,390
Retained Earnings	2,915	3,384
Accumulated Other Comprehensive Loss	(50)	(49)
Total Common Equity	5,255	5,725
Long-Term Debt, Net	5,906	6,473
Total Capitalization	11,161	12,198
Current Liabilities:		
Short-term borrowings	350	941
Current portion of long-term debt	727	17
Accounts payable	438	404
Customer deposits and customer prepayments	112	168
Taxes accrued	214	201
Interest accrued	87	84
Dividends declared	86	80
Derivative financial instruments	6	35
Other	93	135
Total Current Liabilities	2,113	2,065
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,261	2,159
Asset retirement obligations	568	558
Pension and postretirement benefits	360	373
Unrecognized tax benefits	19	219
Regulatory liabilities	3,059	930
Other	198	205
Total Deferred Credits and Other Liabilities	5,465	4,444
Commitments and Contingencies (Note 10)	—	—
Total	$ 18,739	$ 18,707

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Operations

Years Ended December 31, (Millions of dollars, except per share amounts)	2017	2016	2015
Operating Revenues:			
Electric	$ 2,659	$ 2,614	$ 2,551
Gas-regulated	874	788	811
Gas-nonregulated	874	825	1,018
Total Operating Revenues	4,407	4,227	4,380
Operating Expenses:			
Fuel used in electric generation	594	576	660
Purchased power	80	64	52
Gas purchased for resale	1,156	1,054	1,287
Other operation and maintenance	737	755	715
Impairment loss	1,118	—	—
Depreciation and amortization	382	371	358
Other taxes	264	254	234
Total Operating Expenses	4,331	3,074	3,306
Gain on sale of CGT, net of transaction costs	—	—	234
Operating Income	76	1,153	1,308
Other Income (Expense), net	56	55	42
Gain on sale of SCI, net of transaction costs	—	—	107
Interest charges, net of allowance for borrowed funds used during construction of $18, $19 and $15	(363)	(342)	(318)
Income (Loss) Before Income Tax Expense	(231)	866	1,139
Income Tax Expense (Benefit)	(112)	271	393
Net Income (Loss)	$ (119)	$ 595	$ 746
Earnings (Loss) Per Share of Common Stock	$ (0.83)	$ 4.16	$ 5.22
Weighted Average Common Shares Outstanding (millions)	143	143	143
Dividends Declared Per Share of Common Stock	$ 2.45	$ 2.30	$ 2.18

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)

Years Ended December 31, (Millions of dollars)	2017	2016	2015
Net Income (Loss)	$ (119)	$ 595	$ 746
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $(4), $2 and $(7)	(7)	4	(12)
Cash flow hedging activities reclassified to interest expense, net of tax of $4, $4 and $4	7	7	7
Cash flow hedging activities reclassified to gas purchased for resale, net of tax of $-, $4 and $9	(1)	6	15
Net unrealized gains (losses) on cash flow hedging activities	(1)	17	10
Deferred Costs of Employee Benefit Plans:			
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	—	(1)	—
Net deferred costs of employee benefit plans	—	(1)	—
Other Comprehensive Income (Loss)	(1)	16	10
Total Comprehensive Income (Loss)	$ (120)	$ 611	$ 756

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2017	2016	2015
Cash Flows From Operating Activities:			
Net Income (Loss)	$ (119)	$ 595	$ 746
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain on sale of subsidiaries	—	—	(355)
Impairment loss	1,118	—	—
Deferred income taxes, net	(911)	242	(31)
Depreciation and amortization	406	389	368
Amortization of nuclear fuel	44	57	46
Allowance for equity funds used during construction	(23)	(29)	(27)
Carrying cost recovery	(34)	(17)	(12)
Changes in certain assets and liabilities:			
Receivables	(56)	(112)	188
Income tax receivable	(56)	(142)	—
Inventories	(93)	(43)	(16)
Prepayments	(5)	11	211
Regulatory assets	181	(114)	(31)
Regulatory liabilities	1,051	(2)	(1)
Accounts payable	24	44	(78)
Unrecognized tax benefits	(224)	175	31
Taxes accrued	13	(41)	61
Pension and other postretirement benefits	(20)	51	(6)
Derivative financial instruments	(3)	(9)	(9)
Other assets	(47)	(44)	(3)
Other liabilities	(77)	81	(23)
Net Cash Provided From Operating Activities	1,169	1,092	1,059
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,225)	(1,579)	(1,153)
Proceeds from sale of subsidiaries	—	—	647
Proceeds from guaranty settlement	1,096	—	—
Proceeds from investments (including derivative collateral returned)	145	860	1,117
Purchase of investments (including derivative collateral posted)	(143)	(788)	(1,018)
Payments upon interest rate derivative contract settlement	(39)	(113)	(263)
Proceeds from interest rate derivative contract settlement	—	—	10
Net Cash Used For Investing Activities	(166)	(1,620)	(660)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	—	—	14
Proceeds from issuance of long-term debt	150	592	491
Repayments of long-term debt	(17)	(117)	(166)
Dividends	(344)	(325)	(309)
Short-term borrowings, net	(591)	410	(387)
Deferred financing costs	—	—	(3)
Net Cash Provided From (Used For) Financing Activities	(802)	560	(360)
Net Increase in Cash and Cash Equivalents	201	32	39
Cash and Cash Equivalents, January 1	208	176	137
Cash and Cash Equivalents, December 31	$ 409	$ 208	$ 176
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $18, $19 and $15)	$ 346	$ 328	$ 306
—Income taxes paid	2	229	184
—Income taxes received	184	166	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures (including nuclear fuel)	139	109	244
Capital leases	8	15	6

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Changes in Common Equity

	Common Stock				Accumulated Other Comprehensive Income (Loss)			
Millions	**Shares**	**Outstanding Amount**	**Treasury Amount**	**Retained Earnings**	**Gains (Losses) on Cash Flow Hedges**	**Deferred Costs of Employee Benefit Plans**	**Total AOCI**	**Total**
Balance as of January 1, 2015	143	$ 2,388	$ (10)	$ 2,684	$ (63)	$ (12)	$ (75)	$ 4,987
Net Income				746				746
Other Comprehensive Income (Loss)								
Losses arising during the period					(12)	—	(12)	(12)
Losses/amortization reclassified from AOCI					22	—	22	22
Total Comprehensive Income (Loss)				746	10	—	10	756
Issuance of Common Stock	—	14	(2)					12
Dividends Declared				(312)				(312)
Balance as of December 31, 2015	143	$ 2,402	(12)	3,118	(53)	(12)	(65)	5,443
Net Income				595				595
Other Comprehensive Income (Loss)								
Gains (Losses) arising during the period					4	(1)	3	3
Losses/amortization reclassified from AOCI					13	—	13	13
Total Comprehensive Income				595	17	(1)	16	611
Dividends Declared				(329)				(329)
Balance as of December 31, 2016	143	$ 2,402	(12)	3,384	(36)	(13)	(49)	5,725
Net Loss				(119)				(119)
Other Comprehensive Income (Loss)								
Losses arising during the period					(7)	—	(7)	(7)
Losses/amortization reclassified from AOCI					6	—	6	6
Total Comprehensive Income (Loss)				(119)	(1)	—	(1)	(120)
Dividends Declared				(350)				(350)
Balance as of December 31, 2017	143	$ 2,402	$ (12)	$ 2,915	$ (37)	$ (13)	$ (50)	$ 5,255

Dividends declared per share of common stock were $2.45, $2.30 and $2.18 for 2017, 2016 and 2015, respectively.

See Notes to Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of comprehensive income (loss), changes in equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedule listed in the Part IV at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Emphasis of Matter

As discussed in Note 10 to the financial statements, the abandoned Nuclear Project has led to legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

We have served as the Company's auditor since 1945.

South Carolina Electric & Gas Company and Affiliates
Consolidated Balance Sheets

December 31, (Millions of dollars)	2017	2016
Assets		
Utility Plant In Service	$ 12,161	$ 11,510
Accumulated Depreciation and Amortization	(4,124)	(3,991)
Construction Work in Progress	375	4,813
Nuclear Fuel, Net of Accumulated Amortization	208	271
Utility Plant, Net ($711 and $756 related to VIEs)	8,620	12,603
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	71	69
Assets held in trust, net-nuclear decommissioning	136	123
Other investments	2	3
Nonutility Property and Investments, Net	209	195
Current Assets:		
Cash and cash equivalents	395	164
Receivables:		
Customer, net of allowance for uncollectible accounts of $4 and $3	390	378
Affiliated companies	32	16
Income taxes	198	53
Other	85	94
Inventories:		
Fuel	90	83
Materials and supplies	149	143
Prepayments	82	88
Derivative financial instrument	54	—
Other current assets	2	1
Total Current Assets ($191 and $85 related to VIEs)	1,477	1,020
Deferred Debits and Other Assets:		
Regulatory assets	5,476	2,030
Other	164	243
Total Deferred Debits and Other Assets ($50 and $52 related to VIEs)	5,640	2,273
Total	$ 15,946	$ 16,091

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2017	2016
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,860	$ 2,860
Retained Earnings	1,982	2,481
Accumulated Other Comprehensive Loss	(4)	(3)
Total Common Equity	4,838	5,338
Noncontrolling interest	142	134
Total Equity	4,980	5,472
Long-Term Debt, net	4,441	5,154
Total Capitalization	9,421	10,626
Current Liabilities:		
Short-term borrowings	252	804
Current portion of long-term debt	723	12
Accounts payable	251	247
Affiliated payables	102	122
Customer deposits and customer prepayments	70	126
Taxes accrued	208	195
Interest accrued	67	68
Dividends declared	82	79
Derivative financial instruments	2	28
Other	47	55
Total Current Liabilities	1,804	1,736
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,173	1,939
Asset retirement obligations	529	522
Pension and postretirement benefits	217	232
Unrecognized tax benefits	19	236
Regulatory liabilities	2,667	695
Other	97	89
Other - affiliate	19	16
Total Deferred Credits and Other Liabilities	4,721	3,729
Commitments and Contingencies (Note 10)	—	—
Total	$ 15,946	$ 16,091

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Comprehensive Income (Loss)

For the Years Ended December 31, (Millions of dollars)	2017	2016	2015
Operating Revenues:			
Electric	$ 2,659	$ 2,614	$ 2,551
Electric - nonconsolidated affiliate	5	5	6
Gas	405	366	372
Gas - nonconsolidated affiliate	1	1	1
Total Operating Revenues	3,070	2,986	2,930
Operating Expenses:			
Fuel used in electric generation	465	472	559
Fuel used in electric generation - nonconsolidated affiliate	129	104	102
Purchased power	80	64	52
Gas purchased for resale	206	174	162
Gas purchased for resale - nonconsolidated affiliate	—	9	31
Other operation and maintenance	417	403	380
Other operation and maintenance - nonconsolidated affiliate	187	211	199
Impairment loss	1,118	—	—
Depreciation and amortization	312	302	294
Other taxes	241	227	211
Other taxes - nonconsolidated affiliate	5	7	6
Total Operating Expenses	3,160	1,973	1,996
Operating Income (Loss)	(90)	1,013	934
Other Income (Expense), net	35	31	25
Interest charges, net of allowance for borrowed funds used during construction of $15, $18 and $14	(288)	(270)	(248)
Income (Loss) Before Income Tax Expense	(343)	774	711
Income Tax Expense (Benefit)	(171)	248	231
Net Income (Loss) and Total Comprehensive Income (Loss)	(172)	526	480
Less Net Income and Total Comprehensive Income Attributable to Noncontrolling Interest	13	13	14
Earnings (Loss) and Comprehensive Income Available (Loss Attributable) to Common Shareholder	$ (185)	$ 513	$ 466
Dividends Declared on Common Stock	$ 323	$ 305	$ 285

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Cash Flow

For the Years Ended December 31, (Millions of dollars)	2017	2016	2015
Cash Flows From Operating Activities:			
Net income (Loss)	$ (172)	$ 526	$ 480
Adjustments to reconcile net income to net cash provided from operating activities:			
Impairment loss	1,118	—	—
Deferred income taxes, net	(780)	207	8
Depreciation and amortization	323	310	294
Amortization of nuclear fuel	44	57	46
Allowance for equity funds used during construction	(15)	(26)	(25)
Carrying cost recovery	(34)	(17)	(12)
Changes in certain assets and liabilities:			
Receivables	(32)	(47)	85
Receivables - affiliate	12	(3)	16
Income tax receivable	(145)	(53)	—
Inventories	(60)	(35)	(24)
Prepayments	6	(4)	70
Regulatory assets	185	(94)	(29)
Other regulatory liabilities	899	(5)	(3)
Accounts payable	20	8	11
Accounts payable - affiliate	(28)	13	(17)
Unrecognized tax benefits	(241)	192	31
Taxes accrued	13	(104)	129
Pension and other postretirement benefits	(21)	39	(5)
Other assets	(46)	(99)	57
Other liabilities	(43)	58	(28)
Other liabilities - affiliate	3	(1)	(6)
Net Cash Provided From Operating Activities	1,006	922	1,078
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(928)	(1,399)	(1,008)
Proceeds from guaranty settlement	1,096	—	—
Proceeds from investments and sales of assets (including derivative collateral returned)	118	794	975
Purchase of investments (including derivative collateral posted)	(122)	(740)	(887)
Payments upon interest rate derivative contract settlement	(39)	(113)	(263)
Proceeds from interest rate derivative contract settlement	—	—	10
Proceeds from investment in affiliate	—	9	71
Investment in affiliate	(28)	—	—
Net Cash Used For Investing Activities	97	(1,449)	(1,102)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	—	494	491
Repayment of long-term debt	(12)	(112)	(11)
Dividends	(319)	(301)	(285)
Short-term borrowings, net	(552)	384	(289)
Short-term borrowings-nonconsolidated affiliate, net	8	(4)	(50)
Contribution from parent	3	100	204
Return of capital to parent	—	—	(4)
Deferred financing costs	—	—	(2)
Net Cash Provided From Financing Activities	(872)	561	54
Net Increase in Cash and Cash Equivalents	231	34	30
Cash and Cash Equivalents, January 1	164	130	100
Cash and Cash Equivalents, December 31	$ 395	$ 164	$ 130
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $15, $18 and $14)	$ 269	$ 251	$ 228
—Income taxes paid	47	289	89
—Income taxes received	145	189	84
Noncash Investing and Financing Activities:			
Accrued construction expenditures (including nuclear fuel)	99	95	230
Capital leases	8	14	6

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Changes in Equity

	Common Stock					
Millions	**Shares**	**Amount**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Non-controlling Interest**	**Total Equity**
Balance at January 1, 2015	40	$ 2,560	$ 2,077	$ (3)	$ 123	$ 4,757
Earnings available for common shareholder			466		14	480
Deferred cost of employee benefit plans, net of tax $-				—		—
Total Comprehensive Income			466	—	14	480
Capital contributions from parent		200			—	200
Cash dividends declared			(278)		(8)	(286)
Balance at December 31, 2015	40	2,760	2,265	(3)	129	5,151
Earnings Available for Common Shareholder			513		13	526
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			513	—	13	526
Capital contributions from parent		100			—	100
Cash dividends declared			(297)		(8)	(305)
Balance at December 31, 2016	40	2,860	2,481	(3)	134	5,472
Earnings (Loss) Available for (Attributable to) Common Shareholder			(185)		13	(172)
Deferred Cost of Employee Benefit Plans, net of tax $-				(1)		(1)
Total Comprehensive Income (Loss)			(185)	(1)	13	(173)
Capital contributions from parent		—			3	3
Cash dividends declared			(314)		(8)	(322)
Balance at December 31, 2017	40	$ 2,860	$ 1,982	$ (4)	$ 142	$ 4,980

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
South Carolina Electric & Gas Company and Affiliates
Notes to Consolidated Financial Statements

The following notes to the consolidated financial statements are a combined presentation. Except as otherwise indicated herein, each note applies to the Company and Consolidated SCE&G; however, Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation or its subsidiaries (other than Consolidated SCE&G).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

The Company

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina, the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia and conducts other energy-related business.

The accompanying consolidated financial statements reflect the accounts of SCANA, the following wholly-owned subsidiaries, and subsidiaries that formerly were wholly-owned during the periods presented.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	SCANA Services, Inc.
South Carolina Generating Company, Inc.	SCANA Corporate Security Services, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Communications Holdings, Inc.

SCANA reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance. Discussions regarding the Company's financial results necessarily include the results of Consolidated SCE&G.

Consolidated SCE&G

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs) and accordingly, Consolidated SCE&G's consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G’s parent. As a result, GENCO’s and Fuel Company’s equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G’s consolidated financial statements.

GENCO owns a coal-fired electric generating station with a 605 MW net generating capacity (summer rating). GENCO’s electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO’s property (carrying value of approximately $503 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G’s nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Dispositions

In the first quarter of 2015, SCANA sold CGT and SCI. CGT was an interstate natural gas pipeline regulated by FERC that transported natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provided fiber optic communications and other services and built, managed and leased communications towers in several southeastern states, and it was sold to Spirit Communications. These sales resulted in recognition of pre-tax gains totaling approximately $342 million. The pre-tax gain from the sale of CGT is included within Operating Income and the pre-tax gain from the sale of SCI is included within Other Income (Expense) on the Company's consolidated statement of operations.

CGT and SCI operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment. The sales of CGT and SCI did not represent a strategic shift that had a major effect on the Company's operations; therefore, these sales did not meet the criteria for classification as discontinued operations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

No estimate is made for legal costs expected to be incurred in connection with loss contingencies. Such costs are recorded when incurred.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company's regulated subsidiaries calculated AFC using average composite rates of 5.6% for 2017, 5.3% for 2016, and 6.1% for 2015. Consolidated SCE&G calculated AFC using average composite rates of 3.9% for 2017, 4.7% for 2016, and 5.6% for 2015. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property, and in most cases, include provisions for future cost of removal. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. In addition, CGT was sold in the first quarter of 2015 (see Dispositions herein) and excluded from the 2015 calculation of composite weighted average depreciation rates. The composite weighted average depreciation rates for utility plant assets were as follows:

	2017	2016	2015
SCE&G	2.55%	2.56%	2.55%
GENCO	2.66%	2.66%	2.66%
PSNC Energy	3.03%	2.90%	2.94%
Weighted average of above	2.63%	2.61%	2.61%
Consolidated SCE&G	2.55%	2.56%	2.56%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in Fuel used in electric generation and recovered through the fuel cost component of retail electric rates.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Unit 1. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement. Unit 2 and Unit 3 have been reclassified from construction work in progress to a regulatory asset as a result of the decision to stop their construction. See additional discussion at Note 2.

As of December 31,	2017	2016	
	Unit 1	Unit 1	Unit 2 and Unit 3
Percent owned	66.7%	66.7%	55.0%
Plant in service	$ 1.5 billion	$ 1.3 billion	—
Accumulated depreciation	$ 637.6 million	$ 634.4 million	—
Construction work in progress	$ 110.1 million	$ 167.7 million	$ 4.2 billion

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for the units. These amounts totaled $53.8 million at December 31, 2017 and $76.2 million at December 31, 2016.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2017, and 2016, SCE&G incurred $26.1 million and $23.8 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, SCE&G accrues $17.2 million annually for its portion of the nuclear refueling outages scheduled from the spring of 2014 through the spring of 2020. Refueling outage costs incurred for which SCE&G was responsible totaled $1.8 million in 2016 in preparation for the Spring 2017 outage and $23.2 million in 2017.

Goodwill

The Company considers certain amounts categorized by FERC as acquisition adjustments to be goodwill. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. Accounting guidance adopted by the Company gives it the option to perform a qualitative assessment of impairment ("step zero"). Based on this qualitative assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with a two-step quantitative assessment. If the quantitative assessment becomes necessary, step one requires estimation of the fair value of the reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Should a write-down be required, such a charge would be treated as an operating expense.

For each period presented, assets with a carrying value of $210 million for PSNC Energy (Gas Distribution segment), net of a writedown of $230 million taken in 2002, were classified as goodwill. The Company utilized the step zero qualitative assessment in its evaluations as of January 1, 2018 and as of January 1, 2017 and was not required to use the two-step quantitative assessment.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The asset balance held in trust reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Temporary cash investments having original maturities of three months or less at time of purchase are considered to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements, treasury bills and money market funds.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Unbilled revenues totaled \$220.9 million at December 31, 2017 and \$178.9 million at December 31, 2016 for the Company. Unbilled revenues totaled \$140.3 million at December 31, 2017 and \$117.6 million at December 31, 2016 for Consolidated SCE&G. Other receivables consist primarily of amounts due from Santee Cooper related to the jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable.

PSNC Energy, a subsidiary of SCANA, utilizes an asset management and supply service agreement with a counterparty for certain natural gas storage facilities. Such counterparty held, through an agency relationship, 39% and 40% of PSNC Energy's natural gas inventory at December 31, 2017 and December 31, 2016, respectively, with a carrying value of \$11.5 million and \$9.8 million, respectively. Under the terms of this agreement, PSNC Energy receives storage asset management fees of which 75% are credited to customers. This agreement expires on March 31, 2019.

Income Taxes

SCANA files consolidated federal income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if such impacts are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, such adjustments are charged or credited to deferred income tax expense. Also, see Note 5 for a discussion of the impact of adjustments recorded upon enactment of the Tax Act.

Consolidated SCE&G is included in the consolidated federal income tax returns of SCANA. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities, including Consolidated SCE&G, record costs that have been or are expected to be allowed in the ratemaking process in periods different from the periods in which the costs would be charged to expense, or record revenues in periods different from the periods in which the revenues would be recorded, by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations for refunds to customers are primarily classified on the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Certain deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as Receivables - Customer or Customer deposits and customer prepayments, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Premiums, discounts and debt issuance costs are presented within long-term debt and are amortized as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Statement of Operations Presentation

Revenues and expenses arising from regulated businesses and, in the case of the Company, the retail natural gas marketing business (including those activities of segments described in Note 12) are presented within Operating Income (Loss), and all other activities are presented within Other Income (Expense). Consistent with this presentation, the Company presents the 2015 gain on the sale of CGT within Operating Income and the 2015 gain on the sale of SCI within Other Income (Expense).

Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not billed.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost proceedings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent proceedings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy's PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings (Loss) Per Share

The Company computes basic earnings (loss) per share by dividing net income (loss) by the weighted average number of common shares outstanding for the period. When applicable, the Company computes diluted earnings (loss) per share using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method.

New Accounting Matters

Recently Adopted

In the first quarter of 2017, the Company and Consolidated SCE&G adopted the following accounting guidance issued by the FASB. The adoption of this guidance had no impact on their respective financial statements except as indicated.

- Guidance issued in August 2014 requires an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern. See related disclosure at Note 10.
- Guidance issued in July 2015 requires most inventory to be measured at the lower of cost and net realizable value.
- Guidance issued in October 2016 requires entities to recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs.

In January 2017, the FASB issued accounting guidance to simplify the accounting for goodwill impairment by removing Step 2 of the goodwill impairment test. The guidance is effective for years beginning in 2020, though early adoption after January 1, 2017 is allowed. The Company adopted this guidance on January 1, 2018, and its adoption had no impact on its financial statements.

Pending Adoption

In the first quarter of 2018, the Company and Consolidated SCE&G will adopt the following accounting guidance issued by the FASB.

- Guidance issued in May 2014 for revenue arising from contracts with customers supersedes most prior revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides for a five-step analysis in determining when and how revenue is recognized, and requires revenue recognition to depict the transfer of promised goods or services to customers, based on the transfer of control, in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. In addition, this guidance requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The analysis of contracts with customers to which the guidance might be applicable has been completed and activities of the FASB's Transition Resource Group for Revenue Recognition, particularly as they relate to the treatment of CIAC, ARP and the collectability of revenue of utilities subject to rate regulation have been considered. Specifically, the Company and Consolidated SCE&G have concluded that their use of CIAC is outside the scope of the new revenue recognition guidance. The Company and Consolidated SCE&G have determined that aspects of SCE&G's WNA and, for the Company, PSNC Energy's CUT allow for revenue adjustments to be recognized prior to amounts being reflected in customer bills. These revenue adjustments, which give rise to regulatory assets or liabilities, represent ARPs that are outside the scope of the new guidance and will be reported as Other operating revenue separately from revenue from contracts with customers on the statement of operations. An evaluation of the enhanced disclosure requirements is being completed, including determining the appropriate disaggregation of revenue.

  The Company and Consolidated SCE&G will adopt this guidance using the modified retrospective method, and comparative periods will not be restated. In connection with this adoption, the Company has determined that its gas marketing subsidiary serves as an agent for gas distribution services in its retail market. Accordingly, certain pass through charges that the Company currently records within Gas-nonregulated revenues, and which are entirely offset within Gas purchased for resale, in the future will be recorded net on the statements of operations. The Company and Consolidated SCE&G do not anticipate that the adoption of this guidance will have any material impacts on their respective financial statements, but its adoption will result in additional disclosures. The adoption of this guidance will not result in a cumulative effect adjustment to beginning retained earnings.

- Guidance issued in January 2016 changes how entities measure certain equity investments and financial liabilities, among other things. Entities will be required to make a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective, with certain exceptions. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018 and do not anticipate that its adoption will have a significant impact on their respective financial statements.

- Guidance issued in August 2016 is intended to reduce diversity in cash flow statement classification related to certain transactions, and entities must apply the guidance retrospectively to all periods presented. The adoption of this guidance will have no impact on the financial statements of the Company and Consolidated SCE&G.

- Guidance issued in November 2016 clarifies how restricted cash should be presented on the statement of cash flows, and entities must apply the guidance retrospectively to all periods presented. The adoption of this guidance will have no impact on the financial statements of the Company and Consolidated SCE&G.

- Guidance issued in March 2017 changes the required presentation of net periodic pension and postretirement benefit costs. Under this guidance, such costs will be separated into service cost components and other components. The service cost components will be presented in the same line item (or items) as other compensation costs arising from services rendered by employees during the period. The other components will be reported in the income statement separately from the service cost component and outside operating income. Only the service cost component will be eligible for capitalization in assets. Entities must apply this guidance on a retrospective basis for the presentation of the service cost component and the other components, and on a prospective basis for the capitalization of only the service cost component. As permitted, service cost and other costs disclosed in related footnotes to previously issued financial statements will be used when estimating retrospective changes for such costs in the income statements for prior periods. Due to regulatory overlay, non-service cost components related to regulated operations that are capitalized in assets under current accounting guidance will be deferred within regulatory assets in the future. As a result, the adoption of this guidance will not have a material impact on the financial statements of the Company and Consolidated SCE&G.

The Company and Consolidated SCE&G will adopt the following accounting guidance issued by the FASB when indicated below.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over 12 months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily on the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight-line basis, also depending on the nature of the assets and relative consumption. In January 2018, FASB amended this accounting guidance to provide an optional transition practical expedient that would allow adopters to not evaluate under the new guidance existing or expired land easements that were not previously accounted for as leases under existing guidance. The new guidance is effective for years beginning in 2019, and the Company and Consolidated SCE&G do not anticipate that its adoption will impact their respective financial statements other than increasing amounts reported for assets and liabilities on the balance sheet and changing the place on their respective statements of operations on which certain expenses are recorded. No impact on net income (loss) is expected. The identification and analysis of leasing and related contracts to which the guidance might be applicable has begun. In addition, the Company and Consolidated SCE&G have begun implementation of a third party software tool that will assist with initial adoption and ongoing compliance. Specifically, preliminary system configuration has been completed and data from certain leases are being entered.

In June 2016, the FASB issued accounting guidance requiring the use of a current expected credit loss impairment model for certain financial instruments. The new model is applicable to trade receivables and most debt instruments, among other financial instruments, and in certain instances may result in impairment losses being recognized earlier than under current guidance. The Company and Consolidated SCE&G must adopt this guidance beginning in 2020, including interim periods, though the guidance may be adopted in 2019. The Company and Consolidated SCE&G have not determined when this guidance will be adopted or what impact it will have on their respective financial statements.

In August 2017, the FASB issued accounting guidance to simplify the application of hedge accounting. Among other things, the new guidance will enable more hedging strategies to qualify for hedge accounting, will allow entities more time to perform an initial assessment of hedge effectiveness, and will permit an entity to perform a qualitative assessment of effectiveness for certain hedges instead of a quantitative one. For cash flow hedges that are highly effective, all changes in the fair value of the derivative hedging instrument will be recorded in other comprehensive income and will be reclassified to earnings in the same period that the hedged item impacts earnings. Fair value hedges will continue to be recorded in current earnings, and any ineffectiveness will impact the income statement. In addition, changes in the fair value of a derivative will be recorded in the same income statement line as the earnings effect of the hedged item, and additional disclosures will be required related to the effect of hedging on individual income statement line items. The guidance must be applied to all outstanding instruments using a modified retrospective method, with any cumulative effect adjustment recorded to opening retained earnings as of the beginning of the first period in which the guidance becomes effective. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2019, though early adoption is permitted, and have not determined what impact such adoption will have on their respective financial statements.

In February 2018, the FASB issued accounting guidance allowing entities to reclassify from AOCI to retained earnings any amounts for stranded tax effects resulting from the Tax Act. The guidance must be applied either in the period of adoption or retrospectively to each period in which the effect of the change was recognized. The Company and Consolidated SCE&G must adopt this guidance beginning in 2019, including interim periods, though the guidance may be adopted earlier. The Company and Consolidated SCE&G have not determined when this guidance will be adopted or what impact it will have on their respective statements of financial position. No impact is expected on statements of operations or cash flows.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved SCE&G's participation in a DER program and recovery of related costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G is to implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. This nameplate capacity goal was achieved in 2017.

By order dated April 29, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties to decrease the total fuel cost component of retail electric rates. SCE&G reduced the total fuel cost component of retail electric rates to reflect lower projected fuel costs and to eliminate over-collected balances of approximately $61 million for base fuel and environmental costs over a 12-month period beginning with the first billing cycle of May 2016. SCE&G also began to recover projected DER program costs of approximately $6.9 million beginning with the first billing cycle of May 2016.

By order dated April 27, 2017, the SCPSC approved a settlement agreement among SCE&G, the ORS and the SCEUC, to increase the total fuel cost component of retail electric rates. SCE&G agreed to set its base fuel component to produce a projected under recovery of $61.0 million over a 12-month period beginning with the first billing cycle of May 2017. SCE&G also agreed to recover, over a 12-month period beginning with the first billing cycle of May 2017, projected DER program costs of approximately $16.5 million. Additionally, deferral of carrying costs will be allowed for base fuel component under-collected balances as they occur.

In October 2017, the SCPSC initiated its 2018 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 10, 2018.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G has removed from rate base certain deferred income tax assets arising from capital expenditures related to Unit 2 and Unit 3 and accrued carrying costs on those amounts during periods in which they were not included in rate base. Such carrying costs were determined at SCE&G’s weighted average long-term debt borrowing rate and were recorded as a regulatory asset and other income. Carrying costs totaled $18.8 million and $14.0 million during 2017 and 2016, respectively. As part of the impairment loss described in Note 10, accumulated carrying costs related to the Nuclear Project totaling $51.0 million were written off.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2017	First billing cycle of May	$37.0 million
2016	First billing cycle of May	$37.6 million
2015	First billing cycle of May	$32.0 million

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider was designed to allow SCE&G to recover projected pension costs, including under-collections, over a 12-month period, beginning with the first billing cycle in May 2016.

By order dated March 1, 2017, the SCPSC approved SCE&G's request to decrease its pension costs rider. The change in the pension rider decreased annual revenue by approximately $11.9 million. The pension rider is designed to allow SCE&G to recover projected pension costs, net of the previously over-collected balance, over a 12-month period, beginning with the first billing cycle in May 2017.

In December 2017, the ORS filed a petition with the SCPSC requesting all investor-owned utilities under the SCPSC's jurisdiction to report the impact of the Tax Act on their individual company's operations. The Tax Act contains provisions that lower the federal corporate tax rate from 35% to 21% effective January 1, 2018. The petition requested that utilities file an estimate of the Tax Act's effects on their most recent test year information available, including an explanation of those effects, and requested that utilities propose procedures for changing rates to reflect the impacts. Lastly, the petition requested that the SCPSC state in its order that rates in effect as of January 1, 2018, be subject to refund so that ratepayers receive the benefit of the tax law changes as of January 1, 2018. By order dated January 10, 2018, the SCPSC granted the ORS petition but did not state that rates in effect as of January 1, 2018 would be subject to refund. SCE&G provided its comments on January 24, 2018, concerning the timing and the format of the report.

In January 2018, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved the filing would allow recovery of $37.0 million of costs and net lost revenues associated with DSM programs, along with an incentive to invest in such programs.

Electric - BLRA and Joint Petition

Under the BLRA, SCE&G filed revised rates with the SCPSC in 2015 and 2016 to incorporate the financing cost of incremental construction work in progress incurred for the Nuclear Project. Rate adjustments were based on SCE&G's updated cost of debt and capital structure and on an allowed ROE. No revised rates filing was pursued in 2017. The SCPSC approved recovery of the following amounts.

Increase	Effective for bills rendered on and after	Amount	Allowed ROE	
2.7%	November 27, 2016	$64.4 million	10.50%	*
2.6%	October 30, 2015	$64.5 million	11.00%	

*Applied prospectively for purposes of calculating revised rates under the BLRA on and after January 1, 2016.

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for Unit 2 and Unit 3 which had been developed in connection with the October 2015 Amendment (see Note 10). On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, the ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. By order dated February 28, 2017, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement, and that denial was not appealed.

The construction schedule approved by the SCPSC in November 2016 provided for contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively. The approved capital cost schedule included incremental capital costs that totaled $831 million, raising SCE&G's total project capital cost as then approved to an estimated amount of approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for the Nuclear Project from 10.5% to 10.25%. This revised ROE was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G could not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request was denied because SCE&G was out of compliance with its approved capital cost schedule or BLRA construction milestone schedule, subject to certain extensions. See also Abandoned Nuclear Project in Note 10.

Following WEC and WECTEC's bankruptcy filing on March 29, 2017, on June 22, 2017, the Friends of the Earth and the Sierra Club filed a complaint against SCE&G with the SCPSC, requesting that the SCPSC initiate a formal proceeding to direct SCE&G to immediately cease and desist from expending any further capital costs related to the construction of Unit 2 and Unit 3; to determine the prudence of acts and omissions by SCE&G in connection with this construction; to review and determine the prudence of abandonment of Unit 2 and Unit 3 and of the available least cost efficiency and renewable energy alternatives; and to remedy, abate and make due reparations for the rates charged to ratepayers related to the construction of Unit 2 and Unit 3. SCE&G filed its answer to the complaint and a motion to dismiss the complaint on July 19, 2017. On October 4, 2017, the SCPSC ordered proceedings under this complaint to be coordinated with proceedings for the Request filed by the ORS on September 26, 2017, described below, and allowed discovery to proceed. SCE&G's subsequent petition for rehearing and reconsideration was denied by the SCPSC on November 1, 2017. Proceedings related to this complaint have been consolidated with proceedings for the Request and the Joint Petition as described below.

On August 1, 2017, SCE&G filed the Abandonment Petition with the SCPSC which sought recovery of costs expended on the construction of Unit 2 and Unit 3, including certain costs incurred subsequent to SCE&G's last revised rates update, other costs under the abandonment provisions of the BLRA, and affirmation of SCE&G's decision to abandon construction of Unit 2 and Unit 3, among other things. Subsequently, SCE&G management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew the Abandonment Petition on August 15, 2017. See additional discussion at Note 10.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which had been previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed with the SCPSC a motion to amend its request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. A hearing on the parties' motions was held on December 12, 2017, and included the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, a large industrial customer, and several environmental groups.

By order dated December 20, 2017, the SCPSC denied SCE&G's Motion to Dismiss the Request and ordered that a hearing be set on the Request. In addition, the SCPSC ordered the ORS to perform a thorough inspection and audit, within 30 days, to determine the reasonableness of SCE&G's retail electric rates and to determine the reasonableness of SCE&G's statements regarding the potential effect that the removal of approximately $445 million in annual revenues, as requested by the ORS, could have on SCE&G. The SCPSC also granted the ORS's motion to amend the Request and consider the monetization of the Toshiba payout along with any other related factors that may be appropriate in determining a fair and reasonable rate. SCE&G intends to vigorously contest the Request, but cannot give any assurance as to the timing or outcome of this matter. Proceedings for the Request, the complaint filed by Friends of the Earth and the Sierra Club on June 22, 2017, and the Joint Petition discussed below have been consolidated.

On November 20, 2017, the ORS filed a letter with the SCPSC providing the ORS's preliminary list for stabilization and protection of the site where Unit 2 and Unit 3 are located and suggesting that the SCPSC have SCE&G respond to the ORS's November 20, 2017 letter and "explain why there is no violation of S.C. Code Ann. § 58-27-1300." The SCPSC granted the ORS's request, and SCE&G filed its response with the SCPSC on December 27, 2017.

On January 12, 2018, SCE&G and Dominion Energy filed with the SCPSC the Joint Petition for review and approval of a proposed business combination whereby SCANA would become a wholly-owned subsidiary of Dominion Energy. In the Joint Petition, approval of a customer benefits plan and a cost recovery plan for the Nuclear Project is also sought. Key provisions of this Joint Petition are summarized at Note 10. A hearing on this matter has not yet been scheduled.

On January 19, 2018, the ORS filed a report with the SCPSC in response to the SCPSC's order for a thorough inspection and audit of SCE&G's statements regarding potential adverse effects that could result from the removal of annual BLRA revenues. The ORS report relied on the analysis of bankruptcy counsel to conclude that the suspension of revised rates collections is unlikely to force SCE&G into bankruptcy. Notwithstanding this conclusion, the ORS predicted that there is 35% likelihood of an SCE&G bankruptcy if revised rates are terminated. The report also indicated that a full audit, as ordered by the SCPSC, would require upwards of 90 days to complete. SCE&G filed responses to the ORS report alleging numerous deficiencies in it, including that the report was not verified by an accountant and that it contained incorrect and misleading accounting conclusions, particularly with regard to the timing and magnitude of any impairment loss that would be required by GAAP. On January 31, 2018, the SCPSC ordered the ORS to complete this previously ordered thorough audit, inspection and examination of SCE&G's accounting records by March 30, 2018, encouraged them to employ the assistance of a utility financial professional if needed, and indicated that a request by the ORS for an extension of time would not be considered unreasonable.

Gas - SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2017	2.2% Increase	$8.6 million
2016	1.2% Increase	$4.1 million
2015	No change	—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2017, 2016 and 2015 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent. See Electric - Base Rates for a discussion of the ORS petition related to the Tax Act, which also applies to Gas - SCE&G.

Gas - PSNC Energy

PSNC Energy's Rider D rate mechanism allows it to recover from customers all prudently incurred gas costs and certain related uncollectible expenses as well as losses on negotiated gas and transportation sales.

PSNC Energy establishes rates using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy’s gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

On October 28, 2016, the NCUC granted PSNC Energy a net annual increase of approximately $19.1 million, or 4.39%, in rates and charges to customers, and set PSNC Energy's authorized ROE at 9.7%. In addition, the NCUC has authorized PSNC Energy to use a tracker mechanism to recover the incurred capital investment and associated costs of complying with federal standards for pipeline integrity and safety requirements that are not in current base rates. PSNC Energy has filed biannual applications to adjust its rates for this purpose, and the NCUC has approved those applications for the incremental annual revenue requirements, as follows:

Rates Effective	Incremental Increase
March 1, 2017	$1.9 million
September 1, 2017	$0.7 million

In December 2017, in connection with PSNC Energy's 2017 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2017.

On January 3, 2018, the NCUC sought reports from its jurisdictional utilities as to how they planned to respond to the Tax Act. In its response on February 1, 2018, PSNC Energy proposed certain adjustments to its rates that, if enacted, would serve to reduce amounts that are currently being collected from customers based on pre-Tax Act rates. PSNC Energy cannot determine when the NCUC may take action on this matter.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, the Company and Consolidated SCE&G have recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Except for certain unrecovered Nuclear Project costs and other unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	The Company		Consolidated SCE&G	
	December 31,		December 31,	
Millions of dollars	2017	2016	2017	2016
Regulatory Assets:				
Unrecovered Nuclear Project costs	$ 3,976	—	$ 3,976	—
Accumulated deferred income taxes	—	$ 316	—	$ 307
AROs and related funding	434	425	410	403
Deferred employee benefit plan costs	305	342	273	309
Deferred losses on interest rate derivatives	456	620	456	620
Other unrecovered plant	105	117	105	117
DSM Programs	59	59	59	59
Carrying costs on deferred tax assets related to the Nuclear Project	—	32	—	32
Pipeline integrity management costs	51	33	8	6
Environmental remediation costs	30	32	25	26
Deferred storm damage costs	24	20	24	20
Deferred costs related to uncertain tax position	—	15	—	15
Other	140	119	140	116
Total Regulatory Assets	$ 5,580	$ 2,130	$ 5,476	$ 2,030
Regulatory Liabilities:				
Monetization of guaranty settlement	$ 1,095	—	$ 1,095	—
Accumulated deferred income taxes	1,076	23	914	14
Asset removal costs	757	755	527	529
Deferred gains on interest rate derivatives	131	151	131	151
Other	—	1	—	1
Total Regulatory Liabilities	$ 3,059	$ 930	$ 2,667	$ 695

Regulatory assets for unrecovered Nuclear Project costs have been recorded based on such amounts not being probable of loss in accordance with the accounting guidance on abandonments, whereas the other regulatory assets have been recorded based on the probability of their recovery. All regulatory assets represent incurred costs that may be deferred under applicable GAAP for regulated operations. The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders certain of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by one of these regulatory agencies, including unrecovered nuclear project costs that are the subject of regulatory proceedings as further discussed in Note 10. In recording such costs as regulatory assets, management believes the costs would be allowable under existing rate-making concepts that are embodied in rate orders or current state law. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation, changes in state law, other changes in the regulatory environment or changes in accounting requirements, the Company or Consolidated SCE&G could be required to write off all or a portion of its regulatory assets and liabilities. Such an event could have a material effect on the Company's and Consolidated SCE&G's financial statements in the period the write-off would be recorded.

Unrecovered Nuclear Project costs represents expenditures by SCE&G that have been reclassified from construction work in progress as a result of the decision to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs under the abandonment provisions of the BLRA or through other regulatory means, net of an estimated impairment loss and the transfer of certain assets described at Note 10.

Accumulated deferred income taxes contained within regulatory assets represent deferred tax liabilities that arise from utility operations that have not been included in customer rates. A portion of these regulatory assets related to depreciation and are netted within regulatory liabilities in the current period.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Unit 1 and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 107 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. SCE&G recovers deferred pension costs through utility rates of approximately $2 million annually for electric operations, which will end in 2044, and approximately $1 million annually for gas operations, which will end in 2027. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees up to approximately 11 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when such amounts are applied otherwise at the direction of the SCPSC. See also Note 10 for a discussion of certain amounts that were treated as impaired as of December 31, 2017.

Other unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent SCE&G's deferred costs associated with electric demand reduction programs, and such deferred costs are currently being recovered over approximately five years through an approved rate rider.

Carrying costs on deferred tax assets related to the Nuclear Project were calculated on accumulated deferred income tax assets associated with Unit 2 and Unit 3 which were not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs were written off as a part of the impairment loss in 2017. See also Note 10.

Pipeline integrity management costs represent operating and maintenance costs incurred to comply with federal regulatory requirements related to natural gas pipelines. PSNC Energy is recovering costs totaling $4.1 million annually through 2021. PSNC Energy is continuing to defer pipeline integrity costs, and as of December 31, 2017 costs of $26.6 million have been deferred pending future approval of rate recovery. SCE&G amortizes $1.9 million of such costs annually.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G or PSNC Energy. SCE&G's remediation costs are expected to be recovered over periods of up to approximately 17 years, and PSNC Energy's remediation costs total $6.9 million are being recovered over a five year period that will end in 2021.

Deferred storm damage costs represent costs incurred in excess of amounts previously collected through SCE&G's SCPSC-approved storm damage reserve, and for which SCE&G expects to receive future recovery through customer rates.

Deferred costs related to uncertain tax position primarily represented the estimated amounts of domestic production activities deductions foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest expense and other costs arising from this uncertain tax position. SCE&G's current customer rates reflect the availability of domestic production activities deductions. These net deferred costs were written off as a part of the impairment loss in 2017. See Note 5 and Note 10.

Various other regulatory assets are expected to be recovered through rates over periods through 2047.

Monetization of guaranty settlement represents proceeds received under or arising from the monetization of the Toshiba Settlement, net of certain expenses.

Accumulated deferred income taxes contained within regulatory liabilities represent (i) excess deferred income taxes arising from the remeasurement of deferred income taxes upon the enactment of the Tax Act (certain of which are protected under normalization regulations and will be amortized over the remaining lives of related property, and certain of which will be amortized to the benefit of customers over a prescribed period as instructed by regulators) and (ii) deferred income taxes arising from investment tax credits, offset by (iii) deferred income taxes that arise from utility operations that have not been included in customer rates (a portion of which relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years). See also Note 5.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

3. COMMON EQUITY

Authorized shares of SCANA common stock were 200 million as of December 31, 2017 and 2016. Authorized shares of SCE&G common stock were 50 million as of December 31, 2017 and 2016. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2017 and 2016.

SCANA’s articles of incorporation do not limit the dividends that may be paid on its common stock, and the articles of incorporation of each of SCANA's subsidiaries contain no such limitations on their respective common stock. SCANA has agreed to obtain the consent of Dominion Energy, which consent cannot be unreasonably withheld, prior to making dividend payments to shareholders greater than $0.6125 per share for any quarter while the Merger Agreement is pending.

SCE&G’s bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. SCE&G's bond indenture permits the payment of dividends on SCE&G's common stock only either (1) out of its Surplus (which as defined in the bond indenture equates to its retained earnings) or (2) in case there is no Surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, the Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2017 and 2016, retained earnings of approximately $93.9 million and $79.0 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

PSNC Energy’s note purchase and debenture purchase agreements contain provisions that could limit the payment of cash distributions, including dividends, on PSNC Energy's common stock. These agreements generally limit the sum of distributions to an amount that does not exceed $30 million *plus* 85% of Consolidated Net Income (as therein defined) accumulated after December 31, 2008 *plus* the net proceeds of issuances by PSNC Energy of equity or convertible debt securities (as therein defined). As of December 31, 2017, this limitation would permit PSNC Energy to pay cash distributions in excess of $100 million.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

The Company

December 31, Dollars in millions	Maturity	2017 Balance	2017 Rate	2016 Balance	2016 Rate
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%
SCANA Senior Notes (unsecured) (a)	2018 - 2034	75	2.18%	79	1.63%
SCE&G First Mortgage Bonds (secured)	2018 - 2065	4,840	5.80%	4,840	5.79%
GENCO Notes (secured)	2018 - 2024	207	5.94%	213	5.93%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.52%	122	3.51%
PSNC Energy Senior Debentures and Notes	2020 - 2046	600	5.19%	450	5.53%
Other	2018 - 2027	28	2.83%	27	2.76%
Total debt		6,672		6,531	
Current maturities of long-term debt		(727)		(17)	
Unamortized discount, net		(1)		(1)	
Unamortized debt issuance costs		(38)		(40)	
Total long-term debt, net		$ 5,906		$ 6,473	

Consolidated SCE&G

December 31, Dollars in millions	Maturity	2017 Balance	2017 Rate	2016 Balance	2016 Rate
First Mortgage Bonds (secured)	2018 - 2065	$ 4,840	5.80%	$ 4,840	5.79%
GENCO Notes (secured)	2018 - 2024	207	5.94%	213	5.93%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.52%	122	3.51%
Other	2018 - 2027	28	2.83%	26	2.76%
Total debt		5,197		5,201	
Current maturities of long-term debt		(723)		(12)	
Unamortized premium, net		1		1	
Unamortized debt issuance costs		(34)		(36)	
Total long-term debt, net		$ 4,441		$ 5,154	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%).
(b) Includes variable rate debt of $67.8 million at December 31, 2017 (rate of 1.85%) and 2016 (rate of 0.76%) which are hedged by fixed swaps.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. Also in June 2016, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2017, PSNC Energy issued $150 million of 4.18% senior notes due June 30, 2047. In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from these sales were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

The Company's long-term debt maturities will be $727 million in 2018, $16 million in 2019, $366 million in 2020, $494 million in 2021 and $264 million in 2022. These amounts include, for Consolidated SCE&G, $723 million in 2018, $12 million in 2019, $11 million in 2020, $40 million in 2021 and $9 million in 2022.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be issued (Bond Ratio). For the year ended December 31, 2017, the Bond Ratio was 5.24. Adjusted Net Earnings, as therein defined, excludes the impairment loss.

Lines of Credit and Short-Term Borrowings

At December 31, 2017 and 2016, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	Total	SCANA	SCE&G	PSNC Energy
December 31, 2017				
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 350.3	—	$ 251.6	$ 98.7
Weighted average interest rate		—	1.92%	1.93%
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,646.4	$ 397.0	$ 1,148.1	$ 101.3
December 31, 2016				
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 940.5	$ 64.4	$ 804.3	$ 71.8
Weighted average interest rate		1.43%	1.04%	1.07%
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,056.2	$ 332.6	$ 595.4	$ 128.2

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to credit agreements in the amounts and for the terms described above. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018. Were adverse developments to occur with respect to uncertainties highlighted elsewhere, the ability of SCE&G or GENCO to secure renewal of this short-term borrowing authority may be adversely impacted.

Each of the Company and Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2017, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $37 million and investments due from an affiliate of $28 million. At December 31, 2016, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $29 million. On SCE&G's consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense (benefit) are as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Current taxes (benefit):						
Federal	$ (414)	$ 36	$ 382	$ (410)	$ 50	$ 208
State	18	13	57	(18)	13	32
Total current taxes (benefit)	(396)	49	439	(428)	63	240
Deferred tax (benefit) expense, net:						
Federal	323	203	(36)	261	167	(3)
State	(37)	21	(7)	(2)	20	(3)
Total deferred taxes (benefit)	286	224	(43)	259	187	(6)
Investment tax credits:						
Amortization of amounts deferred-state	—	—	(1)	—	—	(1)
Amortization of amounts deferred-federal	(2)	(2)	(2)	(2)	(2)	(2)
Total investment tax credits	(2)	(2)	(3)	(2)	(2)	(3)
Total income tax expense (benefit)	$ (112)	$ 271	$ 393	$ (171)	$ 248	$ 231

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Net income (loss)	$ (119)	$ 595	$ 746	$ (185)	$ 513	$ 466
Income tax expense (benefit)	(112)	271	393	(171)	248	231
Noncontrolling interest	—	—	—	13	13	14
Total pre-tax income (loss)	$ (231)	$ 866	$ 1,139	$ (343)	$ 774	$ 711
Income taxes (benefit) on above at statutory federal income tax rate	$ (81)	$ 303	$ 399	$ (120)	$ 271	$ 249
Increases (decreases) attributed to:						
State income taxes (less federal income tax effect)	(7)	27	38	(8)	26	24
State investment tax credits (less federal income tax effect)	(5)	(5)	(6)	(5)	(5)	(6)
Allowance for equity funds used during construction	(8)	(10)	(9)	(5)	(9)	(9)
Deductible dividends—401(k) Retirement Savings Plan	(9)	(10)	(10)	—	—	—
Amortization of federal investment tax credits	(2)	(2)	(2)	(2)	(2)	(2)
Section 45 tax credits	(8)	(8)	(9)	(8)	(8)	(9)
Domestic production activities deduction	(18)	(23)	(18)	(18)	(23)	(18)
Remeasurement of deferred taxes upon enactment of Tax Act	30	—	—	(1)	—	—
Realization of basis differences upon sale of subsidiaries	—	—	7	—	—	—
Other differences, net	(4)	(1)	3	(4)	(2)	2
Total income tax expense (benefit)	$ (112)	$ 271	$ 393	$ (171)	$ 248	$ 231

The tax effects of significant temporary differences comprising net deferred tax liabilities are as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	2017	2016	2017	2016
Deferred tax assets:				
Net operating loss and tax credit carryforward	$ 600	—	$ 541	—
Toshiba settlement	273	—	273	—
Nondeductible accruals	88	$ 148	42	$ 53
Asset retirement obligation, including nuclear decommissioning	141	213	132	200
Regulatory liability, non-property accumulated deferred income tax	54	—	54	—
Financial instruments	15	22	—	—
Unamortized investment tax credits	8	15	8	15
Deferred fuel costs	—	17	—	17
Other	6	10	5	8
Total deferred tax assets	1,185	425	1,055	293
Deferred tax liabilities:				
Property, plant and equipment	1,220	2,159	1,035	1,856
Regulatory asset, unrecovered nuclear plant costs	962	—	962	—
Deferred employee benefit plan costs	60	105	53	93
Regulatory asset, asset retirement obligation	91	143	85	135
Regulatory asset, other unrecovered plant	27	45	27	45
Demand side management costs	16	23	16	23
Prepayments	21	32	19	30
Other	49	77	31	50
Total deferred tax liabilities	2,446	2,584	2,228	2,232
Net deferred tax liabilities	$ 1,261	$ 2,159	$ 1,173	$ 1,939

The federal and state tax credits and NOL carryforwards are presented below:

	December 31, 2017		
Millions of dollars	The Company	Consolidated SCE&G	Expiration Year
Federal NOL Carryforwards	$ 2,052	$ 1,905	2037
Federal Tax Credits	35	35	2035 - 2037
Federal Charitable Carryforwards	7	5	2021 - 2022
State NOL Carryforwards	2,382	2,301	2037
State Charitable Carryforwards	3	2	2022
Total Tax Credits and NOL Carryforwards	$ 4,479	$ 4,248	

A valuation allowance is needed when it is more likely than not that all or a portion of a deferred tax asset will not be realized. In determining whether a valuation allowance is required, the Company and Consolidated SCE&G consider such factors as prior earnings history, expected future earnings, carryback and carryforward periods, and tax strategies that could potentially enhance the likelihood of the realization of a deferred tax asset. Based on this evaluation, management has concluded that a valuation allowance is not needed.

In December 2017, the Tax Act was enacted, resulting in the remeasurement of all federal deferred income tax assets and liabilities to reflect a 21% federal statutory tax rate. Due to the regulated nature of the Company's and Consolidated SCE&G's operations, the effect of this remeasurement is primarily reflected in deferred income tax balances within regulatory liabilities (see Note 2). In connection with this remeasurement, however, the Company recorded additional deferred income tax expense of approximately $30 million, and Consolidated SCE&G recorded a deferred income tax benefit of approximately $1 million in their respective statements of operations for the year ended December 31, 2017. Upon the eventual filing of the Company's 2017 consolidated income tax return, adjustments to deferred income taxes and deferred income taxes may be recorded; however, these adjustments are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

The State of North Carolina lowered its corporate income tax rate from 6.0% to 5.0% in 2015, 4.0% in 2016, 3% in 2017 and 2.5% effective January 1, 2019. In connection with these changes in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The changes in income tax rates did not and are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

The Company files consolidated federal income tax returns which includes Consolidated SCE&G, and the Company and its subsidiaries file various applicable state and local income tax returns.

The IRS has completed examinations of the Company's federal returns through 2004, and the Company's federal returns through 2009 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2015 as a result of claims discussed below. With few exceptions, the Company, including Consolidated SCE&G, is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes in Unrecognized Tax Benefits

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Unrecognized tax benefits, January 1	$ 350	$ 49	$ 16	$ 350	$ 49	$ 16
Gross increases—uncertain tax positions in prior period	—	94	33	—	94	33
Gross decreases—uncertain tax positions in prior period	(273)	—	(2)	(273)	—	(2)
Gross increases—current period uncertain tax positions	21	207	2	21	207	2
Unrecognized tax benefits, December 31	$ 98	$ 350	$ 49	$ 98	$ 350	$ 49

During 2013 and 2014, the Company amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). The Company also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In 2016 and 2017, the Company claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the design and construction activities of the Nuclear Project, in its 2015 and 2016 income tax returns. The Company expects to claim similar deductions and credits in its 2017 tax return when it is filed in 2018. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models.

The IRS examined the claims in the amended returns, and as the examination progressed without resolution, the Company and Consolidated SCE&G evaluated and recorded adjustments to unrecognized tax benefits; however, none of these changes materially affected the Company's and Consolidated SCE&G's effective tax rate. In October 2016, the examination of the amended tax returns progressed to the IRS Office of Appeals. In addition, the IRS has begun an examination of SCANA's 2013 through 2015 income tax returns, and it is expected that the IRS will also examine later returns.

These IRC Section 174 income tax deductions and IRC Section 41 credits were considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities were recorded as unrecognized tax benefits in the financial statements. Following the abandonment of the Nuclear Project, the Company and Consolidated SCE&G anticipate that an abandonment loss deduction under IRC Section 165 will be claimed on the 2017 tax return. As such, certain of the IRC Section 174 deductions, to the extent they are denied, would instead be deductible in 2017 under IRC Section 165. The abandonment loss deduction is also considered an uncertain tax position; however, under relevant accounting guidance, no estimated unrecognized tax benefits were recorded as of December 31, 2017. The remaining unrecognized tax benefits include the impact of the IRC Section 174 deductions on domestic production activities deductions, credits, and certain unrecognized state tax benefits.

As of December 31, 2017, the Company and Consolidated SCE&G have recorded an unrecognized tax benefit of $98 million ($19 million net of the impact of state deductions on federal returns, net of NOL and credit carryforwards, and net of receivables related to the uncertain tax positions). If recognized, $98 million of the tax benefit would affect the Company's and Consolidated SCE&G's effective tax rates. These unrecognized tax benefits are not expected to increase significantly within the next 12 months. It is also reasonably possible that these unrecognized tax benefits may decrease by $11 million within the next 12 months. No other material changes in the status of the Company's or Consolidated SCE&G's tax positions have occurred through December 31, 2017.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 and 2016 income tax returns and similar claims made in determining taxable income for 2017, and under the terms of an SCPSC order, the Company and Consolidated SCE&G recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, with the expectation that these deferred costs and related interest thereon would be recoverable through customer rates in future years (see Note 2). However, as further described in Note 10, as of December 31, 2017, an impairment loss with respect to such deferred regulatory asset was recorded. SCE&G's current customer rates reflect the availability of domestic production activities deductions.

Also under the terms of an SCPSC order, estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 and 2016 income tax returns was deferred as a regulatory asset and was expected to be recoverable through customer rates in future years. An impairment loss with respect to these deferred amounts was also recorded as of December 31, 2017 (see Note 10). Otherwise, the Company and Consolidated SCE&G recognize interest accrued related to unrecognized tax benefits within interest expense or interest income and recognize tax penalties within other expenses. Amounts recorded for such interest income, interest expense or tax penalties have not been material for any period presented.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Derivative instruments are recognized either as assets or liabilities in the statement of financial position and are measured at fair value. Changes in the fair value of derivative instruments are recognized either in earnings, as a component of other comprehensive income (loss) or, for regulated operations, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures, and in some cases risk limits, are established to control the level of market, credit, liquidity and operational and administrative risks. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Risk Management Officer and other senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statements of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and NYMEX futures and options. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the under- or over-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SCANA Energy, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

Interest rate swaps may be used to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which swaps designated as cash flow hedges are used to synthetically convert variable rate debt to fixed rate debt, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

Forward starting swap agreements that are designated as cash flow hedges may be used in anticipation of the issuance of debt. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For SCANA and its nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated for accounting purposes as cash flow hedges and fair value changes and settlement amounts related to them have been recorded as regulatory assets and liabilities. Settlement losses on swaps have generally been amortized over the lives of subsequent debt issuances and gains have been amortized to interest expense or may be applied as otherwise directed by the SCPSC. However, see Note 10 for a discussion of the impairment of previously deferred regulatory asset amounts related to settlement losses on swaps that had been entered into for debt that was anticipated to be issued in connection with the Nuclear Project.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)		
Hedge designation	**Gas Distribution**	**Gas Marketing**	**Total**
As of December 31, 2017			
Commodity	6,430,000	13,433,000	19,863,000
Energy Management (a)	—	41,856,890	41,856,890
Total (a)	6,430,000	55,289,890	61,719,890
As of December 31, 2016			
Commodity	4,510,000	11,947,000	16,457,000
Energy Management (a)	—	67,447,223	67,447,223
Total (a)	4,510,000	79,394,223	83,904,223

(a) Includes amounts related to basis swap contracts totaling 2,582,000 MMBTU in 2017 and 730,721 MMBTU in 2016.

The aggregate notional amounts of the interest rate swaps were as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	**December 31, 2017**	**December 31, 2016**	**December 31, 2017**	**December 31, 2016**
Designated as hedging instruments	$ 111.2	$ 115.6	$ 36.4	$ 36.4
Not designated as hedging instruments	735.0	1,285.0	735.0	1,285.0

The following table shows the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the consolidated balance sheet, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Fair Values of Derivative Instruments

Millions of dollars	Balance Sheet Location	The Company Asset	The Company Liability	Consolidated SCE&G Asset	Consolidated SCE&G Liability
As of December 31, 2017					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 3		$ 1
	Other deferred credits and other liabilities		24		9
Commodity contracts					
	Prepayments		2		
	Other current liabilities		1		
Total		—	$ 30	—	$ 10
Not designated as hedging instruments					
Interest rate contracts					
	Other deferred debits and other assets				
	Derivative financial instruments	$ 54	$ 1	$ 54	$ 1
	Other deferred credits and other liabilities		4		4
Commodity contracts					
	Other current assets	1			
Energy management contracts					
	Prepayments		1		
	Other current assets	3			
	Other deferred debits and other assets	1			
	Derivative financial instruments		2		
Total		$ 59	$ 8	$ 54	$ 5
As of December 31, 2016					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 4		$ 1
	Other deferred credits and other liabilities		24		8
Commodity contracts					
	Prepayments	$ 5			
	Other current assets	1			
Total		$ 6	$ 28	—	$ 9
Not designated as hedging instruments					
Interest rate contracts					
	Other deferred debits and other assets	$ 71		$ 71	
	Derivative financial instruments		$ 27		$ 27
	Other deferred credits and other liabilities		3		3
Commodity contracts					
	Other current assets	3			
Energy management contracts					
	Prepayments	6	2		
	Other current assets	2	1		
	Other deferred debits and other assets	2			
	Derivative financial instruments		4		
	Other deferred credits and other liabilities		2		
Total		$ 84	$ 39	$ 71	$ 30

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

The Company and Consolidated SCE&G:	**Loss Deferred in Regulatory Accounts**	**Loss Reclassified from Deferred Accounts into Income (Effective Portion)**	
Millions of dollars	**(Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2017			
Interest rate contracts	$ (2)	Interest expense	$ (2)
Year Ended December 31, 2016			
Interest rate contracts	—	Interest expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)

The Company:	**Gain or (Loss) Recognized in OCI, net of tax**	**Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion)**	
Millions of dollars	**(Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2017			
Interest rate contracts	—	Interest expense	$ (7)
Commodity contracts	$ (7)	Gas purchased for resale	1
Total	$ (7)		$ (6)
Year Ended December 31, 2016			
Interest rate contracts	$ (1)	Interest expense	$ (7)
Commodity contracts	5	Gas purchased for resale	(6)
Total	$ 4		$ (13)
Year Ended December 31, 2015			
Interest rate contracts	$ (2)	Interest expense	$ (7)
Commodity contracts	(10)	Gas purchased for resale	(15)
Total	$ (12)		$ (22)

As of December 31, 2017, the Company expects that during the next 12 months reclassifications from AOCI to earnings arising from cash flow hedges will include approximately $3.3 million as an increase to gas cost, assuming natural gas markets remain at their current levels, and approximately $7.2 million as an increase to interest expense, assuming financial markets remain at their current levels. As of December 31, 2017, all of the Company’s commodity cash flow hedges settle by their terms before the end of the fourth quarter of 2020.

As of December 31, 2017, each of the Company and Consolidated SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.5 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

For the Company and Consolidated SCE&G, ineffectiveness on interest rate hedges designated as cash flow hedges was insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

The Company and Consolidated SCE&G: Millions of dollars	Loss Deferred in Regulatory Accounts	Gain (Loss) Reclassified from Deferred Accounts into Income: Location	Amount
Year Ended December 31, 2017			
Interest rate contracts	$ (32)	Interest Expense	$ (3)
Interest rate contracts		Impairment Loss	(173)
Year Ended December 31, 2016			
Interest rate contracts	$ (34)	Other income	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2. For more discussion of amounts reclassified to Impairment Loss, see Note 10.

As of December 31, 2017, the Company and Consolidated SCE&G expect that during the next 12 months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $2.7 million as an increase to interest expense.

Credit Risk Considerations

Certain derivative contracts contain contingent credit features. These features may include (i) material adverse change clauses or payment acceleration clauses that could result in immediate payments or (ii) the posting of letters of credit or termination of the derivative contract before maturity if specific events occur, such as a credit rating downgrade below investment grade or failure to post collateral.

Derivative Contracts with Credit Contingent Features

	The Company		Consolidated SCE&G	
Millions of dollars	**December 31, 2017**	**December 31, 2016**	**December 31, 2017**	**December 31, 2016**
in Net Liability Position				
Aggregate fair value of derivatives in net liability position	$ 33.7	$ 50.3	$ 14.7	$ 30.3
Fair value of collateral already posted	28.9	29.2	10.1	9.2
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	4.8	21.1	4.6	21.1
in Net Asset Position				
Aggregate fair value of derivatives in net asset position	$ 53.5	$ 62.9	$ 53.5	$ 62.0
Fair value of collateral already posted	—	—	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	53.5	62.9	53.5	62.0

In addition, for fixed price supply contracts offered to certain of SCANA Energy's customers, the Company could have called on letters of credit in the amount of $1.2 million related to $4.0 million in commodity derivatives that are in a net asset position at December 31, 2017, compared to letters of credit of $1.5 million related to derivatives of $9.0 million at December 31, 2016, if all the contingent features underlying these instruments had been fully triggered.

Information related to the offsetting derivative assets follows:

Derivative Assets	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2017					
Gross Amounts of Recognized Assets	$ 54	$ 1	$ 4	$ 59	$ 54
Gross Amounts Offset in Statement of Financial Position			—	—	
Net Amounts Presented in Statement of Financial Position	54	1	4	59	54
Gross Amounts Not Offset - Financial Instruments	—			—	—
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 54	$ 1	$ 4	$ 59	$ 54
Balance sheet location					
Other current assets				$ 58	$ 54
Other deferred debits and other assets				1	
Total				$ 59	$ 54
As of December 31, 2016					
Gross Amounts of Recognized Assets	$ 71	$ 9	$ 10	$ 90	$ 71
Gross Amounts Offset in Statement of Financial Position			(4)	(4)	
Net Amounts Presented in Statement of Financial Position	71	9	6	86	71
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 62	$ 9	$ 6	$ 77	$ 62
Balance sheet location					
Prepayments				$ 9	
Other current assets				5	
Other deferred debits and other assets				72	$ 71
Total				$ 86	$ 71

Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2017					
Gross Amounts of Recognized Liabilities	$ 32	3	$ 3	$ 38	$ 15
Gross Amounts Offset in Statement of Financial Position			(1)	(1)	
Net Amounts Presented in Statement of Financial Position	32	3	2	37	15
Gross Amounts Not Offset - Financial Instruments	—			—	—
Gross Amounts Not Offset - Cash Collateral Posted	28		(1)	27	—
Net Amount	$ 60	$ 3	$ 1	$ 64	$ 15
Balance sheet location					
Other current assets				$ 2	
Derivative financial instruments				7	$ 2
Other deferred credits and other liabilities				28	13
Total				$ 37	$ 15

As of December 31, 2016					
Gross Amounts of Recognized Liabilities	$ 58		$ 9	$ 67	$ 39
Gross Amounts Offset in Statement of Financial Position			(3)	(3)	
Net Amounts Presented in Statement of Financial Position	58	—	6	64	39
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Posted	(29)			(29)	(9)
Net Amount	$ 20	—	$ 6	$ 26	$ 21
Balance sheet location					
Derivative financial instruments				$ 35	$ 28
Other deferred credits and other liabilities				29	11
Total				$ 64	$ 39

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Available for sale securities are valued using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded or are open-ended mutual funds registered with the SEC which maintain a stable NAV and are invested in government money market agreements or fully collateralized repurchase agreements. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2017				As of December 31, 2016		
	The Company		Consolidated SCE&G		The Company		Consolidated SCE&G
Millions of dollars	**Level 1**	**Level 2**	**Level 1**	**Level 2**	**Level 1**	**Level 2**	**Level 2**
Assets:							
Available for sale securities	$ 119	—	$ 100	—	$ 14	—	—
Held to maturity securities	—	$ 6	—	—	—	$ 7	—
Interest rate contracts	—	54	—	$ 54	—	71	$ 71
Commodity contracts	1	—	—	—	8	1	—
Energy management contracts	—	4	—	—	6	4	—
Liabilities:							
Interest rate contracts	—	32	—	15	—	58	39
Commodity contracts	2	1	—	—	—	—	—
Energy management contracts	1	4	—	—	2	10	—

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2017 and December 31, 2016 were as follows:

	As of December 31, 2017		As of December 31, 2016	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
The Company	$ 6,632.9	$ 7,399.7	$ 6,489.8	$ 7,183.3
Consolidated SCE&G	5,163.3	5,790.3	5,166.0	5,752.3

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

In connection with the impairment loss described in Note 10, the Company and Consolidated SCE&G determined that the fair value of certain of their nuclear fuel was lower than its carrying amount. At December 31, 2017, this nuclear fuel had an estimated fair value of $43.8 million. This estimate is based on quoted prices received from vendors of nuclear fuel, which are considered to be Level 3 fair value measurements. The Company and Consolidated SCE&G assess the fair value of nuclear fuel in connection with the analysis of impairment described in Note 10 on a quarterly basis.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. SCE&G participates in SCANA's pension plan. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. SCE&G participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	The Company				Consolidated SCE&G			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Benefit obligation, January 1	$ 904.3	$ 855.4	$ 274.7	$ 253.6	$ 768.4	$ 724.0	$ 207.2	$ 191.7
Service cost	21.7	20.7	4.5	4.4	18.1	16.9	3.7	3.6
Interest cost	37.4	39.4	11.5	12.1	31.9	33.4	9.5	9.9
Plan participants' contributions	—	—	1.3	1.7	—	—	1.1	1.3
Actuarial (gain) loss	42.2	45.0	9.7	14.0	36.6	41.8	6.8	11.5
Benefits paid	(72.4)	(56.2)	(12.5)	(11.1)	(62.0)	(47.7)	(10.3)	(9.1)
Amounts Funded to parent	n/a	n/a	n/a	n/a	—	—	(1.4)	(1.7)
Benefit obligation, December 31	$ 933.2	$ 904.3	$ 289.2	$ 274.7	$ 793.0	$ 768.4	$ 216.6	$ 207.2

The accumulated benefit obligation for pension benefits for the Company was $905.8 million at the end of 2017 and $874.3 million at the end of 2016. The accumulated benefit obligation for pension benefits for Consolidated SCE&G was $769.7 million at the end of 2017 and $742.9 million at the end of 2016.The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
Annual discount rate used to determine benefit obligation	3.71%	4.22%	3.74%	4.30%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease gradually to 5.0% for 2023 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate for the Company would increase the postretirement benefit obligation by $1.6 million at December 31, 2017 and by $0.8 million at December 31, 2016. A one percent decrease in the assumed health care cost trend rate for the Company would decrease the postretirement benefit obligation by $1.4 million at December 31, 2017 and by $0.7 million at December 31, 2016. A one percent increase in the assumed health care cost trend rate for Consolidated SCE&G would increase the postretirement benefit obligation by $1.3 million at December 31, 2017 and by $0.6 million at December 31, 2016. A one percent decrease in the assumed health care cost trend rate for Consolidated SCE&G would decrease the postretirement benefit obligation by $1.1 million at December 31, 2017 and by $0.6 million at December 31, 2016.

Funded Status

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2017	2016	2017	2016	2017	2016	2017	2016
Fair value of plan assets	$ 849.6	$ 793.6	—	—	$ 781.3	$ 732.9	—	—
Benefit obligation	933.2	904.3	$ 289.2	$ 274.7	793.0	768.4	$ 216.6	$ 207.2
Funded status	$ (83.6)	$ (110.7)	$ (289.2)	$ (274.7)	$ (11.7)	$ (35.5)	$ (216.6)	$ (207.2)

Amounts recognized on the consolidated balance sheets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2017	2016	2017	2016	2017	2016	2017	2016
Current liability	—	—	$ (13.5)	$ (12.6)	—	—	$ (10.8)	$ (10.4)
Noncurrent liability	$ (83.6)	$ (110.7)	(275.7)	(262.1)	$ (11.7)	$ (35.5)	(205.8)	(196.8)

Amounts recognized in accumulated other comprehensive loss were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2017	2016	2017	2016	2017	2016	2017	2016
Net actuarial loss	$ 8.8	$ 10.4	$ 3.5	$ 2.5	$ 2.1	$ 1.9	$ 1.5	$ 1.0
Prior service cost	0.1	0.1	—	—	—	—	—	—
Total	$ 8.9	$ 10.5	$ 3.5	$ 2.5	$ 2.1	$ 1.9	$ 1.5	$ 1.0

Amounts recognized in regulatory assets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2017	2016	2017	2016	2017	2016	2017	2016
Net actuarial loss	$ 194.8	$ 236.1	$ 43.3	$ 34.7	$ 171.4	$ 208.8	$ 35.9	$ 29.3
Prior service cost	1.2	2.5	—	—	1.0	2.2	—	—
Total	$ 196.0	$ 238.6	$ 43.3	$ 34.7	$ 172.4	$ 211.0	$ 35.9	$ 29.3

In connection with the joint ownership of Summer Station, costs related to the pension benefit obligation attributable to Santee Cooper as of December 31, 2017 and 2016 totaled $21.4 million and $23.4 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2017 and 2016 totaled $14.7 million and $15.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

Pension Benefits	**The Company**		**Consolidated SCE&G**	
Millions of dollars	**2017**	**2016**	**2017**	**2016**
Fair value of plan assets, January 1	$ 793.6	$ 781.7	$ 732.9	$ 720.1
Actual return on plan assets	128.4	68.1	110.4	60.5
Benefits paid	(72.4)	(56.2)	(62.0)	(47.7)
Fair value of plan assets, December 31	$ 849.6	$ 793.6	$ 781.3	$ 732.9

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. SCANA uses a dynamic investment strategy for the management of the pension plan assets. This strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2017 and 2016 and the target allocation for 2018 are as follows:

	Percentage of Plan Assets		
	Target Allocation	**December 31,**	
Asset Category	**2018**	**2017**	**2016**
Equity Securities	58%	58%	57%
Fixed Income	33%	31%	32%
Hedge Funds	9%	11%	11%

For 2018, the expected long-term rate of return on assets will be 7%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan’s historical cumulative actual returns over several periods, considers the expected active and passive returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2017 and 2016, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	The Company 2017	The Company 2016	Consolidated SCE&G 2017	Consolidated SCE&G 2016
Investments with fair value measure at Level 2:				
Mutual funds	$ 120	$ 125	$ 110	$ 115
Short-term investment vehicles	17	16	16	15
US Treasury securities	15	18	14	17
Corporate debt securities	91	82	84	76
Municipals	17	14	15	13
Total assets in the fair value hierarchy	260	255	239	236
Investments at net asset value:				
Common collective trust	498	453	458	418
Joint venture interests	92	86	84	79
Total investments at fair value	$ 850	$ 794	$ 781	$ 733

For all periods presented, assets with fair value measurements classified as Level 1 were insignificant, and there were no assets with fair value measurements classified as Level 3. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2017 or 2016.

Mutual funds held by the plan are open-ended mutual funds registered with the SEC. The price of the mutual funds' shares is based on its NAV, which is determined by dividing the total value of portfolio investments, less any liabilities, by the total number of shares outstanding. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. US Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Common collective trust assets and limited partnerships are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds' net assets at fair value by the units outstanding at each valuation date. Joint venture interests are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and not traded on a daily basis. The valuation of such multi-strategy hedge fund of funds is estimated based on the NAV of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may influence their fair value.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	The Company Pension Benefits	The Company Other Postretirement Benefits	Consolidated SCE&G Pension Benefits	Consolidated SCE&G Other Postretirement Benefits
2018	$ 66.9	$ 13.8	$ 66.9	$ 11.0
2019	64.6	14.6	64.6	11.7
2020	63.9	15.4	63.9	12.3
2021	66.5	16.0	66.5	12.8
2022	72.0	16.5	72.0	13.1
2023-2027	303.0	87.3	303.0	69.6

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals at the end of 2023, no significant contributions to the pension plan are expected to be made for the foreseeable future based on current market conditions and assumptions.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

The Company	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Service cost	$ 21.7	$ 20.7	$ 24.1	$ 4.5	$ 4.4	$ 5.3
Interest cost	37.4	39.4	38.2	11.5	12.1	11.4
Expected return on assets	(54.7)	(55.9)	(62.0)	n/a	n/a	n/a
Prior service cost amortization	1.6	3.9	4.1	—	0.3	0.4
Amortization of actuarial losses	16.3	14.8	13.6	1.0	0.5	2.1
Net periodic benefit cost	$ 22.3	$ 22.9	$ 18.0	$ 17.0	$ 17.3	$ 19.2

Consolidated SCE&G	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Service cost	$ 18.1	$ 16.9	$ 19.3	$ 3.7	$ 3.6	$ 4.4
Interest cost	31.9	33.4	32.2	9.5	9.9	9.4
Expected return on assets	(46.7)	(47.4)	(52.2)	n/a	n/a	n/a
Prior service cost amortization	1.4	3.4	3.4	—	0.3	0.3
Amortization of actuarial losses	13.9	12.5	11.4	0.8	0.4	1.7
Net periodic benefit cost	$ 18.6	$ 18.8	$ 14.1	$ 14.0	$ 14.2	$ 15.8

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

The Company	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Current year actuarial (gain) loss	$ (1.0)	$ 0.6	$ 2.7	$ 1.1	$ 0.8	$ (1.2)
Amortization of actuarial losses	(0.6)	(0.6)	(0.4)	(0.1)	—	(0.1)
Amortization of prior service cost	—	(0.1)	(0.1)	—	—	(0.1)
Total recognized in OCI	$ (1.6)	$ (0.1)	$ 2.2	$ 1.0	$ 0.8	$ (1.4)

Consolidated SCE&G	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Current year actuarial (gain) loss	$ 0.3	—	$ 0.2	$ 0.5	$ 0.3	$ (0.3)
Amortization of actuarial losses	(0.1)	$ (0.1)	(0.1)	—	—	—
Amortization of prior service cost	—	—	(0.1)	—	—	—
Total recognized in OCI	$ 0.2	$ (0.1)	—	$ 0.5	$ 0.3	$ (0.3)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

The Company	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Current year actuarial (gain) loss	$ (27.1)	$ 29.4	$ 9.2	$ 9.4	$ 11.1	$ (18.0)
Amortization of actuarial losses	(14.1)	(12.7)	(11.9)	(0.8)	(0.4)	(1.8)
Amortization of prior service cost	(1.4)	(3.4)	(3.7)	—	(0.3)	(0.3)
Total recognized in regulatory assets	$ (42.6)	$ 13.3	$ (6.4)	$ 8.6	$ 10.4	$ (20.1)

Consolidated SCE&G	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Current year actuarial (gain) loss	$ (24.8)	$ 26.3	$ 12.2	$ 7.3	$ 9.2	$ (14.0)
Amortization of actuarial losses	(12.5)	(11.2)	(10.4)	(0.7)	(0.3)	(1.5)
Amortization of prior service cost	(1.3)	(3.0)	(3.1)	—	(0.2)	(0.3)
Total recognized in regulatory assets	$ (38.6)	$ 12.1	$ (1.3)	$ 6.6	$ 8.7	$ (15.8)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Discount rate	4.22%	4.68%	4.20%	4.30%	4.78%	4.30%
Expected return on plan assets	7.25%	7.50%	7.50%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Health care cost trend rate	n/a	n/a	n/a	6.60%	7.00%	7.00%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2021	2021	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2018 are as follows for the Company. For Consolidated SCE&G such amounts are insignificant:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 0.5	$ 0.1

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2018 are as follows:

	The Company		Consolidated SCE&G	
Millions of Dollars	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 10.2	$ 1.8	$ 9.0	$ 1.5
Prior service cost	0.4	—	0.4	—
Total	$ 10.6	$ 1.8	$ 9.4	$ 1.5

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCANA sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. SCE&G participates in this plan. Contributions are matched 100% up to 6% of an employee’s eligible earnings. Such matching contributions made by the Company totaled $27.9 million in 2017, $27.5 million in 2016 and $26.2 million in 2015. These matching contributions included those made by Consolidated SCE&G, which totaled $23.4 million in 2017, $22.9 million in 2016 and $21.8 million in 2015. Employee deferrals, matching contributions, and earnings on all contributions are fully vested and nonforfeitable at all times.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2015-2017, 2016-2018 and 2017-2019 performance cycles provide for performance measurement and award determination based on performance over a single three-year cycle, with payment of awards being deferred until after the end of the three-year performance cycle. In each of these performance cycles, 30% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash, and 70% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Cash-settled liabilities related to performance cycles totaled approximately $28.0 million in 2017, $18.4 million in 2016 and $20.8 million in 2015 for the Company and approximately $20.2 million in 2017, $13.2 million in 2016 and $6.3 million in 2015 for Consolidated SCE&G.

Fair value adjustments for all performance cycles resulted in compensation expense (benefit) recognized in the statements of operations totaling approximately $(9.0) million in 2017, $25.6 million in 2016 and $18.0 million in 2015 for the Company, of which approximately $(6.3) million in 2017, $17.3 million in 2016 and $12.2 million in 2015 for Consolidated SCE&G (including amounts allocated from SCANA Services). Such fair value adjustments also resulted in capitalized compensation costs of $(1.3) million in 2017, $3.3 million in 2016 and $2.3 million in 2015 for the Company and $(0.9) million in 2017, $3.1 million in 2016 and $0.6 million in 2015 for Consolidated SCE&G. At December 31, 2017, unrecognized compensation cost, which is expected to be recognized over a weighted-average period of 18 months, was $5.4 million for the Company and $4.1 million for Consolidated SCE&G. Large declines in stock price and relative performance in 2017 resulted in reductions of liabilities previously accrued with respect to open performance cycles. In the event of consummation of the merger, additional compensation cost arising from these liability awards may also be recognized.

10. COMMITMENTS AND CONTINGENCIES

Abandoned Nuclear Project

SCE&G, on behalf of itself and as agent for Santee Cooper, entered into the EPC Contract with the Consortium in 2008 for the design and construction of Unit 2 and Unit 3. SCE&G's ownership share in these units is 55%. As discussed below, various difficulties were encountered in connection with the project. The ability of the Consortium to adhere to established budgets and construction schedules was affected by many variables, including unanticipated difficulties encountered in connection with project engineering and the construction of project components, constrained financial resources of the contractors, regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected time frames, the availability of labor and materials at estimated costs and the efficiency of project labor. There were also contractor and supplier performance issues, difficulties in timely meeting critical regulatory requirements, contract disputes, and changes in key contractors or subcontractors. These matters, and others more fully discussed below, were the subject of comprehensive analyses performed by the Company and Santee Cooper (see Contractor Bankruptcy Proceedings and Related Uncertainties below). Based on the results of the Company's analysis, and in light of Santee Cooper's decision to suspend construction on Unit 2 and Unit 3, on July 31, 2017, the Company determined to stop the construction of the units and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means.

EPC Contract and BLRA Matters

The Nuclear Project and SCE&G's related recovery of financing costs through rates has been subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC approved, among other things, a milestone schedule and a capital costs estimates schedule for Unit 2 and Unit 3. Pursuant to the BLRA, this approval constituted a final and binding determination that the units were used and useful for utility purposes, and that the capital costs associated with them were prudent utility costs and expenses and were properly included in rates, so long as Unit 2 and Unit 3 were constructed or were being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the Nuclear Project. As of December 31, 2017, financing costs on $3.5 billion of SCE&G's construction costs for the Nuclear Project, excluding related transmission assets, have been reflected in revised rates under the BLRA, with the last revised rates increase having gone into effect in November 2016. SCE&G estimates that revised rates collections that have accumulated as of December 31, 2017, including collections related to transmission assets expected to be placed into service, total approximately $1.9 billion.

As a result of the decision to abandon the Nuclear Project, amounts reclassified from construction work in progress into regulatory assets, net of impairments described below, are summarized as follows:

Unrecovered Nuclear Project Costs		**Millions of dollars**
Nuclear Project costs as of September 30, 2017, prior to impairment loss and excluding transmission assets	$	4,730
Less Impairment loss recorded in the third quarter of 2017 (See below)		210
Balance of unrecovered Nuclear Project costs as of September 30, 2017		4,520
Less Impairment loss recorded in the fourth quarter of 2017 (See below)		460
Less Nuclear Project and switchyard assets transferred for use by Unit 1		84
Balance of unrecovered Nuclear Project costs as of December 31, 2017 (See Note 2)	$	3,976

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued combined Construction and Operating Licenses in March 2012. In November 2012, and again in September 2015 and November 2016 (see discussion below), the SCPSC approved SCE&G's requested updates to the milestone schedule, revised contractual substantial completion dates, and increases in capital and other costs. As further discussed below, under the current regulatory construct in South Carolina, approval by the SCPSC of cost recovery under the abandonment provisions of the BLRA or through other means will be required as a consequence of the Company's determination on July 31, 2017 to cease construction of the Nuclear Project.

October 2015 Amendment and WEC's Engagement of Fluor

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The amendment became effective in December 2015, at which time Fluor began serving as a subcontracted construction manager for the Consortium. The October 2015 Amendment provided SCE&G and Santee Cooper an option to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G's 55% portion being approximately $3.345 billion). This total amount to be paid would be reduced by amounts paid since June 30, 2015. SCE&G, on behalf of itself and as agent for Santee Cooper, elected the fixed price option, subject to SCPSC approval, on July 1, 2016.

Among other things, the October 2015 Amendment revised the contractual guaranteed substantial completion dates of Unit 2 and Unit 3 to August 31, 2019 and August 31, 2020, respectively, and provided for development of a revised construction milestone payment schedule. In February 2017, WEC notified the Company and Consolidated SCE&G that the contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively, which were reflected in the October 2015 Amendment, would not be met. Instead, WEC provided further revised estimated substantial completion dates of April 2020 and December 2020.

November 2016 SCPSC Order

In May 2016, SCE&G petitioned the SCPSC for approval of the updated construction and capital cost schedules for Unit 2 and Unit 3 which had been developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, the ORS and certain other parties concerning this petition. The

SCPSC also approved SCE&G's election of the fixed price option. By order dated February 28, 2017, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement, and that order was not appealed.

The construction schedule approved by the SCPSC in November 2016 provided for contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively. The approved capital cost schedule included incremental capital costs that totaled $831 million, raising SCE&G's total project capital cost as then approved to an estimated amount of approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for the Nuclear Project from 10.5% to 10.25%. This revised ROE was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. No such revised rates have been sought since that time.

Contractor Bankruptcy Proceedings and Related Uncertainties

On March 29, 2017, WEC and WECTEC, the two members of the Consortium, and certain of their affiliates filed petitions for protection under Chapter 11 of the U.S. Bankruptcy Code, citing a liquidity crisis arising from project contract losses attributable to the Nuclear Project and similar units being built for an unaffiliated company as a material factor that caused WEC and WECTEC to seek protection under the bankruptcy laws. As part of such filing, WEC and WECTEC publicly announced their inability to complete Unit 2 and Unit 3 under the terms of the EPC Contract.

In connection with the bankruptcy filing, SCE&G, Santee Cooper, WEC and WECTEC entered into an Interim Assessment Agreement under which engineering and construction continued on the project and under which SCE&G and Santee Cooper were provided the right to discuss project status with Fluor and other subcontractors and vendors and to obtain from them relevant project information and documents that had been previously contractually unavailable in order for SCE&G and Santee Cooper to perform comprehensive analyses regarding whether or how to proceed with the Nuclear Project. As part of the Interim Assessment Agreement, and to avoid an immediate rejection of the EPC Contract upon the filing of the bankruptcy case, WEC and WECTEC required SCE&G and Santee Cooper to make estimated weekly payments to WEC, WECTEC, subcontractors and vendors, irrespective of the fixed price provisions of the EPC Contract, to permit the time to conduct analyses. SCE&G and Santee Cooper agreed to pay specified costs incurred by the Consortium, Fluor, other subcontractors and vendors for work performed or services rendered while the Interim Assessment Agreement remained in effect.

During the period of the Interim Assessment Agreement, as amended and extended, SCE&G and Santee Cooper evaluated the various elements of the Nuclear Project, including forecasted costs and completion dates, while construction continued and SCE&G and Santee Cooper continued to make payments for such work.

As part of its evaluation, SCE&G considered that, as a result of the bankruptcy process (including WEC and WECTEC's public announcements that they could not perform under the terms of the EPC Contract), the EPC Contract would likely be rejected and that the benefit of the fixed-price terms provided by the EPC Contract would be lost. As such, any cost overruns that would have been absorbed by the Consortium would become the responsibility of SCE&G and Santee Cooper. Additionally, these cost increases and other costs identified by SCE&G would not be fully recoverable from the Consortium or from Toshiba under its payment guaranty or the related Toshiba Settlement, discussed below, and such costs would likely substantially exceed the amount of the Consortium's payment obligations guaranteed by Toshiba.

SCE&G also considered that even the newly revised substantial completion dates identified by WEC of April and December 2020 for Unit 2 and Unit 3, respectively, likely would not be met. As such, the electricity to be produced by each of the units would not qualify for nuclear production tax credits under Section 45J of the IRC. SCE&G's 55% share of these nuclear production tax credits for both Unit 2 and Unit 3 could have totaled as much as approximately$1.4 billion. Failure to meet the newly revised substantial completion dates identified by WEC would result in the nuclear production tax credits not being earned.

On September 1, 2017, SCE&G, for itself and as agent for Santee Cooper, filed with the Bankruptcy Court Proofs of Claim for unliquidated damages against each of WEC and WECTEC. The Proofs of Claim are based upon the anticipatory repudiation and material breach by the Consortium of the EPC Contract, and assert against WEC and WECTEC any and all claims that are based thereon or that may be related thereto. These claims were sold to Citibank on September 27, 2017 as part of the monetization transaction discussed below. Notwithstanding the sale of the claims, SCE&G and Santee Cooper remain responsible for any claims that may be made by WEC and WECTEC against them relating to the EPC Contract.

Toshiba Settlement and Subsequent Monetization

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and WECTEC, and in connection with the October 2015 Amendment, Toshiba, WEC's parent company, reaffirmed its guaranty of WEC's payment obligations. In satisfaction of such guaranty obligations, on July 27, 2017, the Toshiba Settlement was executed under which Toshiba was to make periodic settlement payments from October 2017 through September 2022 in the total amount of approximately $2.2 billion ($1.2 billion for SCE&G's 55% share). The $2.2 billion is subject to offset for payments by WEC that have the effect of satisfying the liens on the project discussed below.

On September 27, 2017, the scheduled payments under the Toshiba Settlement, exclusive of the payment due in October 2017, were purchased by Citibank for a one-time upfront payment of $1.847 billion (approximately $1.016 billion for SCE&G's 55% share), including amounts related to the contractor liens discussed below. The initial payment was then received from Toshiba on October 2, 2017, as scheduled, in the amount of $150 million ($82.5 million for SCE&G's 55% share). SCE&G's share of amounts received, net of certain expenses, total $1.095 billion. The purchase agreement provides that SCE&G and Santee Cooper (each according to its pro rata share) would indemnify Citibank for its losses arising from misrepresentations or covenant defaults under the purchase agreement. SCE&G and Santee Cooper also assigned their claims under the WEC bankruptcy process to Citibank, and agreed to use commercially reasonable efforts to cooperate with Citibank and provide reasonable support necessary for its enforcement of those claims. The proceeds received under or arising from the monetization of the Toshiba Settlement were recorded as cash and as a regulatory liability on the accompanying consolidated balance sheets, as the net value of the proceeds will be utilized to benefit SCE&G's customers in a manner to be determined by the SCPSC. While this determination is pending, SCE&G has utilized portions of the proceeds to repay maturing commercial paper balances, which short-term borrowings had been incurred primarily for the construction of Unit 2 and Unit 3 prior to the decision to stop their construction. See further discussion in Note 4.

A number of subcontractors and vendors to the Consortium have alleged non-payment by the Consortium for amounts owed for work performed on the Nuclear Project and have filed liens on property in Fairfield County, South Carolina, where Unit 2 and Unit 3 were to be located. SCE&G is contesting the filed liens. Payments under the Toshiba Settlement are subject to reduction if WEC pays creditors holding these liens directly. Under these circumstances, SCE&G and Santee Cooper, each in its pro rata share, would be required to make Citibank whole for the reduction. On January 2, 2018, the purchase agreement among SCE&G, Santee Cooper and Citibank was amended to limit the amount that SCE&G and Santee Cooper could be required to reimburse Citibank for valid subcontractor and vendor liens to $60 million ($33 million for SCE&G's 55% share).

Determination to Stop Construction and Related Regulatory, Political and Legal Developments

The BLRA provides that, in the event of abandonment prior to plant completion, costs incurred, including AFC, and a return on those costs, may be recoverable through rates, if the SCPSC determines that the decision to abandon the Nuclear Project was prudent. Based on the evaluation previously discussed, and in light of Santee Cooper's decision to suspend construction, on July 31, 2017, the Company determined to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means. On July 31, 2017, SCE&G gave WEC a five-day notice of termination of the Interim Assessment Agreement and notified WEC of its determination to stop construction of Unit 2 and Unit 3.

On August 1, 2017, SCE&G senior management provided an allowable ex parte briefing to the SCPSC regarding the Nuclear Project and this decision, and SCE&G also filed a petition with the SCPSC which included its plan of abandonment and certain proposed actions which would mitigate related customer rate increases, including a proposal to return to customers the net value of proceeds received by SCE&G under or arising from the monetization of the Toshiba Settlement. Through this petition, SCE&G had sought recovery of such costs expended on the construction of the Nuclear Project, including certain costs incurred subsequent to SCE&G's last revised rates update, and certain other costs under the abandonment provisions of the BLRA. Subsequently, SCE&G's management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow for adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew its petition to abandon the project from the SCPSC on August 15, 2017.

In August 2017, special committees of the South Carolina General Assembly, both in the House of Representatives and in the Senate, began conducting public hearings regarding the decision to abandon the Nuclear Project. Members of SCE&G's senior management, along with representatives from Santee Cooper, the ORS and other interested parties, testified before these committees. Several legislative proposals adverse to the Company and Consolidated SCE&G resulted from the work of these committees and certain adverse proposals have been or are being considered by the General Assembly in 2018. In January 2018, these committees reconvened for the purpose of considering the effects of the proposed merger discussed below on Nuclear Project stakeholders. On January 31, 2018, the South Carolina House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

In September 2017, the Company was served with a subpoena issued by the United States Attorney's Office for the District of South Carolina seeking documents relating to the Nuclear Project. The subpoena requires the Company to produce a broad range of documents related to the project. Also in September 2017, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. In October 2017, the staff of the SEC's Division of Enforcement also issued a subpoena for documents related to an investigation they are conducting related to the Nuclear Project. The Company and Consolidated SCE&G intend to fully cooperate with these investigations. Also in connection with the abandonment of the Nuclear Project, various state or local governmental authorities have attempted and may further attempt to challenge, reverse or revoke one or more previously-approved tax or economic development incentives, benefits or exemptions and may attempt to apply such action retroactively. No assurance can be given as to the timing or outcome of these matters.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the South Carolina General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections. SCE&G estimates that revised rates collections, including collections related to transmission assets expected to be placed into service, currently total approximately $445 million annually, and such amounts accumulated as of December 31, 2017 total approximately $1.9 billion.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed a motion with the SCPSC to amend the Request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. Parties who filed to intervene in the matter or who filed a letter in support of the request by the ORS include the Governor, the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, the SCEUC, certain large industrial customers, and several environmental groups. After conducting a hearing to consider SCE&G's motion, the SCPSC denied the motion on December 20, 2017 and requested that the ORS carry out an inspection, audit and examination of SCE&G's revenue requirements to assist the SCPSC in determining whether SCE&G's present schedule of rates is fair and reasonable and also ordered that a hearing be scheduled to consider the Request. The hearing has not yet been scheduled. SCE&G intends to continue vigorously contesting the Request, but cannot give any assurance as to the timing or outcome of this matter. See also Note 2.

Proposals to Resolve Outstanding Issues

On November 16, 2017, SCE&G announced for public consideration a proposal to resolve outstanding issues relating to the Nuclear Project. Under the proposal, SCE&G electric customers were to receive a 3.5% electric rate reduction, the addition of an existing 540-MW natural gas fired power plant by SCE&G with the acquisition cost borne by SCANA shareholders, and the addition of approximately 100-MW of large scale solar energy by SCE&G. The proposal also provided for the recovery of the nuclear construction costs (net of the proceeds of the Toshiba Settlement not utilized for liquidation of project liens) over 50 years. While SCE&G's proposal was not formally submitted for regulatory approval, discussions with key stakeholders over the ensuing weeks indicated that SCE&G's proposal would not be sufficient to resolve the outstanding issues.

On January 2, 2018, SCANA entered into the Merger Agreement with Dominion Energy, and on January 12, 2018, SCE&G and Dominion Energy filed the Joint Petition requesting SCPSC approval of the merger or a finding that either the merger is in the public interest or that there is an absence of harm arising from the merger. In this petition, the parties commit to providing an up-front, one time rate credit to SCE&G's electric customers totaling approximately $1.3 billion within 90 days of the merger's closing, providing at least a 5% reduction in customer bills, shortening the amortization period for costs related to the Nuclear Project to 20 years, forgoing recovery of approximately $1.7 billion in costs related to the Nuclear Project, and adding an existing 540-MW natural gas fired power plant by SCE&G with no initial investment borne by customers. No assurance can be given as to the timing or outcome of efforts to consummate the Merger Agreement or to obtain approval of the Joint Petition.

Impairment Considerations

Under the current regulatory construct in South Carolina, pursuant to the BLRA or through other means, the ability of SCE&G to recover costs incurred in connection with Unit 2 and Unit 3, and a reasonable return on them, will be subject to review and approval by the SCPSC. In light of the contentious nature of the reviews by legislative committees and others, the adverse impact that would result if proposed legislation is enacted, and the Request being considered by the SCPSC that could result in the suspension of rates currently being collected under the BLRA, as well as the return of such amounts previously collected, there is significant uncertainty as to SCE&G's ultimate ability to fully recover its costs of Unit 2 and Unit 3 and a return on them from its customers. SCE&G continues to contest the specific challenges described above. However, based on the consideration of those challenges, and particularly in light of SCE&G's proposed solution announced on November 16, 2017 and details in the Joint Petition filed by SCE&G and Dominion Energy with the SCPSC on January 12, 2018, the Company and Consolidated SCE&G have determined that a disallowance of recovery of part of the cost of the abandoned plant is both probable and reasonably estimable under applicable accounting guidance. In addition, the Company and Consolidated SCE&G have determined that full recovery of certain other related costs deferred within regulatory assets is less than probable. As a result, as of December 31, 2017, the Company and Consolidated SCE&G have recognized a pre-tax impairment loss totaling $1.118 billion ($690 million net of tax). With the exception of the $210 million loss recorded in the third quarter of 2017 as explained below, this impairment loss was recorded in the fourth quarter of 2017. A discussion of this impairment loss follows:

- A pre-tax impairment loss was recorded with respect to disallowance of unrecovered nuclear project costs of approximately $670 million. This amount includes $210 million recorded in the third quarter of 2017, which represented costs of approximately $1.2 billion that had been expended on the project, exclusive of transmission costs, but which had not yet been determined to be prudent by the SCPSC in connection with revised rates proceedings under the BLRA, offset by the amount of approximately $1 billion, which amount represents the recovery of the Toshiba Settlement proceeds that are in excess of amounts from that settlement that the Company and Consolidated SCE&G estimated may be necessary to satisfy certain project liens. This impairment loss also includes $180 million, which amount arises from SCE&G's entry into an agreement in the fourth quarter of 2017 to purchase in 2018 an existing 540-MW combined cycle gas generating station along with SCE&G's commitment to regulators and the public that the recovery of the initial capital investment in the facility would not be sought from customers. The remaining $280 million of this impairment loss was recorded after consideration of the regulatory and political developments described above.

- A pre-tax impairment loss was recorded in the aggregate amount of $361 million to write off costs which had been previously deferred, primarily as regulatory assets, in connection with the Nuclear Project. Such regulatory assets included deferred losses on interest rate swaps for which debt will not be issued due to the abandonment of the Nuclear Project, carrying costs on deferred tax assets arising from the capitalization of interest costs for tax purposes, net deferred costs and tax benefits related to foregone domestic production activities deductions (net of uncertain tax positions and credits) taken with respect to the project, and taxes associated with equity AFC.

- Finally, an $87 million pre-tax impairment loss was recorded in order to reduce to estimated fair value the carrying value of nuclear fuel acquired for use in Unit 2 and Unit 3.

With the exception of the $87 million related to nuclear fuel, the above impairment loss reflects impacts similar to those that may have resulted had the proposed solution announced November 16, 2017 been implemented. That proposal is presented by SCE&G as a less-favored alternative to the merger benefits and cost recovery plan in the January 12, 2018 Joint

Petition. It is reasonably possible that a change in the estimated impairment loss could occur in the near term. If the merger benefits and cost recovery plan outlined in the Joint Petition is implemented (upon closing of the merger as contemplated in the Merger Agreement), an additional impairment loss and other charges totaling as much as approximately $1.7 billion would be expected to be recorded. This additional impairment loss would result from the write-off of unrecovered Nuclear Project costs of approximately $856 million recorded within regulatory assets and the recording of additional liabilities for customer refunds totaling approximately $1.875 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. If instead the Joint Petition is not approved and the Request by the ORS is approved, and if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, the Company and Consolidated SCE&G may be required to record an additional impairment loss and other charges totaling as much as approximately $4.8 billion. This additional impairment loss would result from the write-off of the remaining unrecovered Nuclear Project costs of $3.976 billion recorded within regulatory assets and the refund of revised rates collections under the BLRA described above of approximately $1.9 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. The Company and Consolidated SCE&G do not currently anticipate that any of the $1.9 billion in revenue previously collected will be subject to refund; however, no assurance can be given as to the outcome of this matter.

Liquidity Considerations

As a result of the decision to stop construction of Unit 2 and Unit 3, downgrades by credit ratings agencies have recently occurred. The Company and Consolidated SCE&G have significant obligations that must be paid within the next 12 months, including long-term debt maturities and capital lease payments of $727 million for the Company (including $723 million for Consolidated SCE&G), short-term borrowings of $350 million for the Company (including $252 million for Consolidated SCE&G), interest payments of approximately $335 million for the Company (including $259 million for Consolidated SCE&G), and future minimum payments for operating leases of $34 million for the Company (including $26 million for Consolidated SCE&G). Working capital requirements, such as those for fuel supply and similar obligations, also arise due to the lag between when such amounts are paid and when related collection of such costs through customer rates occurs.

Management believes as of the date of issuance of these financial statements that it has access to available sources of cash to pay obligations when due over the next 12 months. These sources include committed, long-term lines of credit that expire in December 2020 totaling $1.8 billion for the Company (including $1.2 billion for Consolidated SCE&G). In addition, as of the date of issuance of these financial statements, SCE&G continues to collect in customer rates amounts previously approved under the BLRA, as well as amounts provided for in other orders related to non-BLRA electric and gas rates. However, as further described below, SCANA's credit rating has fallen below investment grade, which has constricted its ability and that of Consolidated SCE&G to issue commercial paper.

As described above, on January 31, 2018, the South Carolina House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Such regulatory, legislative or judicial proceedings outside of the Company's and Consolidated SCE&G's control may result in the temporary or permanent suspension of the approximately $445 million annually of rates being collected currently under the BLRA, the return of such amounts previously collected of $1.9 billion, or the requirement that SCE&G's share of payments received from the Toshiba Settlement ($1.095 billion) be placed in escrow or be refunded to customers. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

Were the SCPSC to grant the relief sought by the ORS in the Request or grant similar relief resulting from legislative action, and as further discussed above in Impairment Considerations, an additional impairment loss or other charges totaling as much as approximately $4.8 billion may be required. Such an impairment loss or other charges would further stress the Company's and Consolidated SCE&G's equity to total capitalization ratio and may result in the Company's and Consolidated SCE&G's ratio of equity to total capitalization falling below minimum levels prescribed in the Company's credit agreements. In such an event, the Company's and Consolidated SCE&G's ability to borrow under their commercial paper programs and credit facilities and their ability to pay future dividends would likely be limited or may trigger events of default under such agreements.

Known and knowable conditions and events when considered in the aggregate as of the date of issuance of these financial statements do not suggest it is probable that the Company and Consolidated SCE&G will not be able to meet obligations as they come due over the next 12 months. However, possible future actions related to rates or refunds could have a material adverse effect on the Company's and Consolidated SCE&G's financial condition, liquidity, results of operations and cash flows such that management's conclusion with respect to its ability to pay obligations when due could change.

Claims and Litigation

Following the Company's decision to stop construction of Unit 2 and Unit 3, putative derivative and class action lawsuits have been filed in multiple state circuit courts and federal district court on behalf of customers, shareholders and SCANA (in the case of the derivative shareholder actions), against SCANA, SCE&G, or both, and in certain cases some of their officers and/or directors. The plaintiffs allege various causes of action, including but not limited to waste, breach of fiduciary duty, negligence, unfair trade practices, unjust enrichment, conspiracy, fraud, constructive fraud, misrepresentation and negligent misrepresentation, promissory estoppel, constructive trust, and money had and received, among other causes of action. Plaintiffs generally seek compensatory and consequential damages and statutory treble damages and such further relief as the court deems just and proper. In addition, certain plaintiffs seek a declaration that SCE&G may not charge its customers to reimburse itself for past and continuing costs of the Nuclear Project. Certain plaintiffs also seek to freeze or appoint a receiver for certain of SCE&G's assets, including all money SCE&G has received under the Toshiba payment guaranty and related settlement agreement and money to be collected from customers for the Nuclear Project.

Putative class action lawsuits have been filed on behalf of investors in federal court against SCANA and certain of its current and former executive officers and directors. The plaintiffs allege, among other things, that defendants violated Section 10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and two suits allege violations of the Racketeer Influenced and Corrupt Organizations Act. In one suit, plaintiff alleges that director defendants violated Section 14(a) of the Exchange Act and SEC Rule 14a-9 by allowing or causing misleading proxy statements to be issued. The plaintiffs in each of these suits seek compensatory and consequential damages and such further relief as the court deems proper.

Lawsuits seeking class action status have also been filed on behalf of investors in the Court of Common Pleas in the Counties of Lexington and Richland, South Carolina, against SCANA, its CEO and directors, Dominion Energy and Sedona Corp. The plaintiffs allege, among other things, that defendants violated their fiduciary duties to shareholders by executing a merger agreement that unfairly deprived plaintiffs of the true value of their SCANA stock, and that Dominion Energy and Sedona Corp. aided and abetted these actions. Among other remedies, the plaintiffs in each case seek to enjoin the merger and rescind the Merger Agreement. In addition, two of the lawsuits seek in the alternative, should the merger be completed, an award of unspecified monetary damages.

A complaint has been filed by Fairfield County against SCE&G making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of the implied duty of good faith and fair dealing, and unfair trade practices related to SCE&G's termination of the FILOT agreement. Plaintiff seeks injunctive relief to prevent SCE&G from terminating the FILOT agreement; actual and consequential damages; treble damages; punitive damages; and attorneys' fees.

The Company has also been served with subpoenas issued by the United States Attorney's Office for the District of South Carolina and the staff of the SEC's Division of Enforcement seeking documents relating to the Nuclear Project. In addition, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee have requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. The Company and Consolidated SCE&G intend to fully cooperate with any such investigations.

On January 26, 2018, the DOR notified the Company that it was initiating an audit of the Company's sales and use tax returns for the periods September 1, 2008 through December 31, 2017. Based on an introductory meeting regarding that audit on February 8, 2018, the Company understands that the DOR's position is that the exemption for sales and use tax for purchases related to the Nuclear Project should not apply because Unit 2 and Unit 3 will not be placed into service and no electricity will be manufactured for sale. The Company intends to vigorously contest the DOR's position.

While the Company and Consolidated SCE&G intend to vigorously contest the lawsuits, claims, and audit positions which have been filed or initiated against them, they cannot predict the timing or outcome of these matters or others that may arise, and adverse outcomes from some of these matters would not be covered by insurance. As noted above, the various claims for damages do not specify an amount for those damages and the number of plaintiffs that are ultimately certified in the potential class actions lawsuits is unknown. In addition, each of the cases referred to above is in its early stages. For these reasons, the Company and Consolidated SCE&G cannot provide any estimate or range of potential loss for these matters at this time, and no accrual for these potential losses has been included in the consolidated financial statements. However, outcomes could have a material adverse effect on the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G are subject to various other claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on the Company's and Consolidated SCE&G's results of operations, cash flows or financial condition.

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Unit 1. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $450 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G’s maximum assessment, based on its two-thirds ownership of Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin and up to $2.33 billion resulting from an event of a non-nuclear origin. The NEIL policies in aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. The NEIL policies permit retrospective assessments under certain conditions to cover insurer’s losses. Based on the current annual premium, SCE&G’s portion of the retrospective premium assessment would not exceed $22.3 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Unit 1 for property damage and outage costs up to $415 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $2.0 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on the Company’s and Consolidated SCE&G's results of operations, cash flows and financial position.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, the Company and Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company and Consolidated SCE&G expect to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at its coal-fired electric generating plants. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future.

On August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule included state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030, and established a phased-in compliance approach beginning in 2022. The rule gave each state from one to three years to issue its SIP, which would ultimately define the specific compliance methodology that would be applied to existing units in that state. On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. As a result of an Executive Order on March 28, 2017, the EPA placed the rule under review and the Court of Appeals agreed to hold the case in abeyance. On October 10, 2017, the Administrator of the EPA signed a notice proposing to repeal the rule on the grounds that it exceeds the EPA's statutory authority. In a separate but related action, the EPA issued an Advance Notice of Proposed Rulemaking on December 18, 2017, to solicit information from the public about a potential future rulemaking to limit greenhouse gas emissions from existing units. The Company and Consolidated SCE&G expect any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual SO_2 emissions and annual and ozone season NO_X emissions to assist in attaining the ozone and fine particle National Ambient Air Quality Standards. The rule establishes an emissions cap for SO_2 and NO_X and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. The State of South Carolina has chosen to remain in the CSAPR program, even though recent court rulings exempted the state. This allows the state to remain compliant with regional haze standards. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any costs incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The MATS rule has been the subject of ongoing litigation even while it remains in effect. Rulings on this litigation are not expected to have an impact on SCE&G or GENCO due to plant retirements, conversions, and enhancements. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits such that, as a facility's NPDES permit is renewed, any new effluent limitations would be incorporated. The ELG Rule had become effective on January 4, 2016, after which state regulators could modify facility NPDES permits to match more restrictive standards, which would require facilities to retrofit with new wastewater treatment technologies. Compliance dates varied by type of wastewater, and some were based on a facility's five-year permit cycle and thus could range from 2018 to 2023. However, the ELG Rule is under reconsideration by the EPA and has been stayed administratively. The EPA has decided to conduct a new rulemaking that could result in revisions to certain flue gas desulfurization wastewater and bottom ash transport water requirements in the ELG Rule. Accordingly, in September 2017 the EPA finalized a rule that resets compliance dates under the ELG Rule to a range from November 1, 2020 to December 31, 2023. The EPA indicates that the new rulemaking process may take up to three years to complete, such that any revisions to the ELG Rule likely would not be final until the summer of 2020. While the Company and Consolidated SCE&G expect that wastewater treatment technology retrofits will be required at Williams and Wateree Stations, any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications to ensure compliance with this rule. Any costs incurred to comply with this rule are expected to be recoverable through rates.

The EPA's final rule for CCR became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. SCE&G has three ponds and three landfills that are governed by the CCR rule. The Company and Consolidated SCE&G do not expect the incremental compliance costs associated with this rule to be significant and expect to recover such costs in future rates.

In December 2016, the U.S. Congress passed and the President signed legislation that creates a framework for EPA-approved state CCR permit programs. Under this legislation, an approved state CCR permit program functions in lieu of the self-implementing Federal CCR rule. The legislation allows states more flexibility in developing permit programs to implement the environmental criteria in the CCR rule. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. To date, South Carolina has not begun drafting a CCR rule.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2016, the federal government has not accepted any spent fuel from Unit 1, and it remains unclear when the repository may become available. SCE&G has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2019 and will cost an additional $9.9 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2017, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $24.6 million and are included in regulatory assets.

Operating Lease Commitments

The Company and Consolidated SCE&G are obligated under various operating leases for land, office space, furniture, equipment, rail cars, a purchase power agreement, and for the Company, airplanes. Leases expire at various dates through 2057.

	Rent Expense		
Millions of dollars	**2017**	**2016**	**2015**
The Company	$ 10.0	$ 10.2	$ 11.1
Consolidated SCE&G	11.4	12.2	12.3

	Future Minimum Rental Payments					
Millions of dollars	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
The Company	$ 34	$ 30	$ 6	$ 6	$ 5	$ 31
Consolidated SCE&G	26	23	1	1	—	17

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is not probable; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2017, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.8 billion.

Asset Retirement Obligations

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2017, SCE&G has recorded AROs of approximately $208 million for nuclear plant decommissioning (see Note 1). In addition, the Company has recorded AROs of approximately $360 million, including $321 million for Consolidated SCE&G, for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	**2017**	**2016**	**2017**	**2016**
Beginning balance	$ 558	$ 520	$ 522	$ 488
Liabilities incurred	—	—	—	—
Liabilities settled	(10)	(11)	(9)	(11)
Accretion expense	25	23	23	22
Revisions in estimated cash flows	(5)	26	(7)	23
Ending balance	$ 568	$ 558	$ 529	$ 522

Revisions in estimated cash flows in 2017 primarily related to ash pond retirement obligations settled and updates in the timing of cash flows as work is completed. Such revisions in 2016 related to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study.

11. AFFILIATED TRANSACTIONS

The Company:

The Company received cash distributions from equity-method investees of $2.8 million in 2017, $3.7 million in 2016 and $4.0 million in 2015. The Company made investments in equity-method investees of $4.6 million in 2017, $5.5 million in 2016 and $4.1 million in 2015.

The Company and Consolidated SCE&G:

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. The net of the total purchases and total sales are recorded in Other expenses on the consolidated statements of operations (for the Company) and of comprehensive income (for Consolidated SCE&G).

Millions of Dollars	2017	2016	2015
Purchases from Canadys Refined Coal, LLC	$ 162.1	$ 161.8	$ 233.2
Sales to Canadys Refined Coal, LLC	161.1	160.8	232.0

Millions of Dollars	2017	2016
Receivable from Canadys Refined Coal, LLC	$ 4.9	$ 16.0
Payable to Canadys Refined Coal, LLC	4.9	16.1

Consolidated SCE&G:

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy to serve its retail gas customers and for certain electric generation requirements.

SCANA Services, on behalf of itself and its parent company, provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative, and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services include amounts capitalized. Amounts expensed are recorded in Other operation and maintenance - nonconsolidated affiliate and Other expenses on the consolidated statements of comprehensive income (loss).

Millions of Dollars	2017	2016	2015
Purchases from SCANA Energy	$ 127.4	$ 111.5	$ 128.5
Direct and Allocated Costs from SCANA Services	302.8	337.7	300.0

Millions of Dollars	2017	2016
Payable to SCANA Energy	$ 10.0	$ 8.8
Payable to SCANA Services	42.0	63.5

Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in 2015.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs is described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1. Intersegment sales and transfers of electricity and gas are recorded based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively. Gas Marketing is comprised of the marketing operations of SCANA Energy, which markets natural gas to retail customers in Georgia and to industrial and large commercial customers and municipalities in the Southeast.

All Other includes the parent company and a services company. In addition, All Other includes gains from the sales of CGT and SCI (see Note 1) and their operating results prior to their sale in the first quarter of 2015. CGT and SCI were nonreportable segments during all periods presented. External revenue and intersegment revenue for All Other related to CGT and SCI were not significant during any period presented.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. Gas Marketing operates in a deregulated environment.

Management uses operating income (loss) to measure segment profitability for its regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, no allocation is made to segments for interest charges, income tax expense (benefit) or assets other than utility plant. For nonregulated operations, management uses net income (loss) as the measure of segment profitability and evaluates total assets for financial position. Intersegment revenue for SCE&G was not significant. Interest income is not reported by segment and is not material. Deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income (loss) consist of the unallocated net income (loss) of regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense (Benefit), Expenditures for Assets and Deferred Tax Assets include primarily the amounts that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs, and totals not allocated to other segments. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Disclosure of Reportable Segments

The Company:

Millions of dollars	**Electric Operations**	**Gas Distribution**	**Gas Marketing**	**All Other**	**Adjustments/ Eliminations**	**Consolidated Total**
2017						
External Revenue	$ 2,659	$ 874	$ 874	—	—	$ 4,407
Intersegment Revenue	5	2	127	$ 389	$ (523)	—
Operating Income (Loss)	(161)	186	n/a	—	51	76
Interest Expense	19	28	1	—	315	363
Depreciation and Amortization	295	85	2	16	(16)	382
Income Tax Expense (Benefit)	8	41	25	(7)	(179)	(112)
Net Income (Loss)	n/a	n/a	27	(46)	(100)	(119)
Segment Assets	11,979	3,259	230	1,042	2,229	18,739
Expenditures for Assets	216	417	2	7	583	1,225
Deferred Tax Assets	6	25	9	—	(40)	—
2016						
External Revenue	$ 2,614	$ 788	$ 825	—	—	$ 4,227
Intersegment Revenue	5	2	111	$ 414	$ (532)	—
Operating Income	957	148	n/a	—	48	1,153
Interest Expense	17	25	1	—	299	342
Depreciation and Amortization	287	82	2	16	(16)	371
Income Tax Expense	8	32	19	—	212	271
Net Income (Loss)	n/a	n/a	30	(18)	583	595
Segment Assets	11,929	2,892	230	1,124	2,532	18,707
Expenditures for Assets	1,275	276	2	11	15	1,579
Deferred Tax Assets	9	32	11	—	(52)	—
2015						
External Revenue	$ 2,551	$ 810	$ 1,018	$ 5	$ (4)	$ 4,380
Intersegment Revenue	6	2	128	413	(549)	—
Operating Income	876	152	n/a	236	44	1,308

Interest Expense	17	23	1	1	276	318
Depreciation and Amortization	277	77	2	16	(14)	358
Income Tax Expense	9	32	18	1	333	393
Net Income (Loss)	n/a	n/a	28	185	533	746
Segment Assets	10,883	2,606	201	998	2,458	17,146
Expenditures for Assets	1,087	203	2	15	(154)	1,153
Deferred Tax Assets	5	29	15	—	(49)	—

Consolidated SCE&G:

Millions of dollars	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2017				
External Revenue	$ 2,664	$ 406	—	$ 3,070
Operating Income (Loss)	(161)	71	—	(90)
Interest Expense	19	—	$ 269	288
Depreciation and Amortization	295	30	(13)	312
Segment Assets	11,979	869	3,098	15,946
Expenditures for Assets	216	65	647	928
Deferred Tax Assets	6	n/a	(6)	—
2016				
External Revenue	$ 2,619	$ 367	—	$ 2,986
Operating Income	957	56	—	1,013
Interest Expense	17	—	$ 253	270
Depreciation and Amortization	287	28	(13)	302
Segment Assets	11,929	825	3,337	16,091
Expenditures for Assets	1,275	78	46	1,399
Deferred Tax Assets	9	n/a	(9)	—
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	876	58	—	934
Interest Expense	17	—	$ 231	248
Depreciation and Amortization	277	28	(11)	294
Segment Assets	10,883	757	3,125	14,765
Expenditures for Assets	1,087	57	(136)	1,008
Deferred Tax Assets	5	n/a	(5)	—

13. OTHER INCOME (EXPENSE), NET

Components of other income (expense), net are as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	2017	2016	2015	2017	2016	2015
Other income	$ 79	$ 64	$ 75	$ 45	$ 29	$ 31
Other expense	(46)	(38)	(60)	(25)	(24)	(31)
Allowance for equity funds used during construction	23	29	27	15	26	25
Other income (expense), net	$ 56	$ 55	$ 42	$ 35	$ 31	$ 25

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

The Company **Millions of dollars, except per share amounts**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
2017					
Total operating revenues	$ 1,173	$ 1,001	$ 1,076	$ 1,157	$ 4,407
Operating income (loss)	316	249	120	(609)	76
Net Income (Loss)	171	121	34	(445)	(119)
Earnings (Loss) per share	1.19	0.85	0.24	(3.11)	(0.83)
2016					
Total operating revenues	$ 1,172	$ 905	$ 1,093	$ 1,057	$ 4,227
Operating income	331	221	348	253	1,153
Net Income	176	105	189	125	595
Earnings per share	1.23	0.74	1.32	0.87	4.16

Consolidated SCE&G **Millions of dollars**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
2017					
Total operating revenues	$ 719	$ 756	$ 856	$ 739	$ 3,070
Operating income (loss)	222	246	123	(681)	(90)
Net Income (Loss)	112	126	42	(452)	(172)
Earnings Available (Loss Attributable) to Common Shareholder	109	123	39	(456)	(185)
2016					
Total operating revenues	$ 717	$ 692	$ 882	$ 695	$ 2,986
Operating income	236	222	359	196	1,013
Net Income	116	113	204	93	526
Earnings Available to Common Shareholder	113	110	201	89	513

See Note 10 for a discussion of the impairment loss that was booked in the third quarter and the fourth quarter of 2017.

15. SUBSEQUENT EVENT

On January 2, 2018, SCANA, Sedona Corp. and Dominion Energy entered into the Merger Agreement pursuant to which Sedona Corp. (a wholly-owned subsidiary of Dominion Energy) agreed to merge into SCANA in a stock-for-stock transaction in which SCANA shareholders would receive 0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock. The completion of the merger is subject to a variety of closing conditions, including the receipt of approvals from SCANA's shareholders and is also subject to consents and approvals or findings from governmental entities, which may impose conditions that could have an adverse effect on the Company or Consolidated SCE&G or could cause either SCANA or Dominion Energy to abandon the merger. The completion of the merger is also subject to an absence of substantive changes in certain South Carolina laws, including the BLRA, that would reasonably be expected to have an adverse effect on SCANA or its subsidiaries, or if any governmental entity enacts any order or there is any change in law which imposes any material change to the terms, conditions or undertakings set forth in the Joint Petition or any significant changes to the economic value of the Joint Petition. See also Note 10.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2017, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCANA's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2017, SCANA's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2017, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCANA's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2017. There has been no change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2017 that has materially affected or is reasonably likely to materially affect SCANA's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA's internal control system was designed by or under the supervision of SCANA's management, including its CEO and CFO, to provide reasonable assurance to SCANA's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA's management assessed the effectiveness of SCANA's internal control over financial reporting as of December 31, 2017. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA's management believes that, as of December 31, 2017, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on SCANA's internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2017, of the Company and our report dated February 22, 2018, expressed an unqualified opinion on those financial statements and financial statement schedule and included an emphasis-of-matter paragraph regarding legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company as a result of the abandoned Nuclear Project.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2017, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2017, SCE&G's disclosure controls and procedures were effective.

Management’s Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2017, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCE&G's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2017. There has been no change in SCE&G’s internal controls over financial reporting during the quarter ended December 31, 2017 that has materially affected or is reasonably likely to materially affect SCE&G’s internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G’s internal control system was designed by or under the supervision of SCE&G’s management, including its CEO and CFO, to provide reasonable assurance to SCE&G’s management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G’s management assessed the effectiveness of SCE&G’s internal control over financial reporting as of December 31, 2017. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).* Based on this assessment, SCE&G’s management believes that, as of December 31, 2017, internal control over financial reporting is effective based on those criteria.

ITEM 9B. OTHER INFORMATION

Not Applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report on Form 10-K at page 34. As permitted by Form 10-K General Instruction G(3), the other information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: As permitted by Form 10-K General Instruction G(3), the information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: As permitted by Form 10-K General Instruction G(3), the information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

Equity securities issuable under SCANA's compensation plans at December 31, 2017 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
2015 Long-Term Equity Compensation Plan	454,023 (1)	n/a	4,545,977
Non-Employee Director Compensation Plan	n/a	n/a	154,635
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	454,023	n/a	4,700,612

(1) Represents unearned non-vested performance share awards from the 2015-2017, 2016-2018 and 2017-2019 performance periods, assuming a target level payout.

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: As permitted by Form 10-K General Instruction G(3), the information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA and SCE&G:

The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm's Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to the Company and Consolidated SCE&G for the fiscal years ended December 31, 2017 and 2016 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	The Company		Consolidated SCE&G	
	2017	2016	2017	2016
Audit Fees [1]	$ 3,670,360	$ 2,857,000	$ 3,127,191	$ 2,316,288
Audit-Related Fees [2]	168,229	171,710	139,172	117,146
Total Fees	$ 3,838,589	$ 3,028,710	$ 3,266,363	$ 2,433,434

[1] Fees for audit services billed in 2017 and 2016 consisted of audits of annual financial statements, comfort letters for securities underwriters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

[2] Fees primarily for employee benefit plan audits and non-statutory audit services.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under Item 8 herein. The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under Item 8 herein. The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts

Description (in millions)		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2017	$ 6	$ 13	—	$ 13	$ 6
	2016	5	12	—	11	6
	2015	7	12	—	14	5
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2017	$ 9	$ 8	—	$ 8	$ 9
	2016	6	5	—	2	9
	2015	5	11	—	10	6
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2017	$ 3	$ 8	—	$ 7	$ 4
	2016	3	6	—	6	3
	2015	4	6	—	7	3
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2017	$ 8	$ 8	—	$ 8	$ 8
	2016	5	5	—	2	8
	2015	3	11	—	9	5

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ J. E. Addison
J. E. Addison, Chief Executive Officer and President

DATE: February 22, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ J. E. Addison
J. E. Addison, Chief Executive Officer and President

(Principal Executive Officer)

/s/ I. N. Griffin

I. N. Griffin, Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV
J. E. Swan, IV
Vice President and Controller
(Principal Accounting Officer)

Directors*:

G. E. Aliff	L. M. Miller
J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
S. A. Decker	A. Trujillo
D. M. Hagood	

*Signed on behalf of each of these persons by Jim Odell Stuckey, Attorney-in-Fact

DATE: February 22, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ J. E. Addison
J. E. Addison, Chief Executive Officer

DATE: February 22, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ J. E. Addison
J. E. Addison
Chief Executive Officer
(Principal Executive Officer)

/s/ I. N. Griffin
I. N. Griffin
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV
J. E. Swan, IV
Vice President and Controller
(Principal Accounting Officer)

Directors*:

G. E. Aliff	L. M. Miller
J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
S. A. Decker	A. Trujillo
D. M. Hagood	

*Signed on behalf of each of these persons by Jim Odell Stuckey, Attorney-in-Fact

DATE: February 22, 2018

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	Applicable to Form 10-K of SCE&	Description
*2.01	X		Agreement and Plan of Merger by and among Dominion Energy, Sedona Corp., and SCANA, dated as of January 2, 2018 (Filed as Exhibit 2.1 to Form 8-K on January 5, 2018 (File No. 001-08809 (SCANA)) and incorporated by reference herein)
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-A to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of December 30, 2016 (Filed as Exhibit 3.05 to Form 10-K for the period ended December 31, 2016 (File No. 001-08809) and incorporated by reference herein)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.03		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.04		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.05		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.06		X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)
10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (Filed as Exhibit 10.01 to Amendment No. 2 of Form 10-Q/A for the quarter ended June 30, 2008 filed on May 25, 2017 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.03	X	X	Amendment to EPC Contract referred to in Exhibit 10.01 dated October 27, 2015 (Filed as Exhibit 10.05 to Form 10-Q for the quarter ended September 30, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
**10.04	X	X	SCANA Executive Deferred Compensation Plan (including amendments through November 25, 2014) (Filed as Exhibit 10.03 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
**10.05	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.06	X	X	SCANA Director Compensation and Deferral Plan (including amendments through August 25, 2016) (Filed herewith)
**10.07	X	X	SCANA Long-Term Equity Compensation Plan effective February 19, 2015 (Filed as Exhibit 4.05 to Registration Statement No. 333-204218 and incorporated by reference herein)
**10.08	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.09	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.10	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.11	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
10.12		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.13	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.14	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
10.15	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A., as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.16	X	X	Amended and Restated Three-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.17	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.18	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
10.19	X	X	Settlement Agreement dated as of July 27, 2017, by and among Toshiba Corporation, SCE&G and Santee Cooper (Filed as Exhibit 99.2 to Form 8-K dated July 27, 2017 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.20	X	X	Trade Confirmation dated September 25, 2017, between SCE&G, Santee Cooper and Citibank, N.A., and associated Assignment and Purchase Agreement, dated September 27, 2017, by and among SCE&G, Santee Cooper and Citibank, N. A. (Filed as Exhibit 10.03 to Form 10-Q for the quarter ended September 30, 2017 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02		X	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS***	X	X	XBRL Instance Document
101. SCH***	X	X	XBRL Taxonomy Extension Schema
101. CAL***	X	X	XBRL Taxonomy Extension Calculation Linkbase
101. DEF***	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB***	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE***	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. SCANA agrees to furnish supplementally to the SEC a copy of any omitted schedule upon request by the SEC.

** Management Contract or Compensatory Plan or Arrangement

*** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM S-4
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

DOMINION ENERGY, INC.
(Exact name of Registrant as specified in its charter)

Virginia	4911	54-1229715
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

120 TREDEGAR STREET RICHMOND, VIRGINIA 23219
(804) 819-2000
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Carlos M. Brown, Esq.
Vice President and General Counsel
Dominion Energy, Inc.
120 Tredegar Street
Richmond, Virginia 23219
Telephone: (804) 819-2690
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Jane Whitt Sellers, Esq.	Jim Stuckey, Esq.	William Kucera, Esq.
McGuireWoods LLP	Senior Vice President and General Counsel	Mayer Brown LLP
Gateway Plaza	SCANA Corporation	71 South Wacker Drive
800 East Canal Street	100 SCANA Parkway	Chicago, Illinois 60606
Richmond, Virginia 23219	Cayce, South Carolina 29033	(312) 782-0600
(804) 775-1000	(803) 217-9000	

Approximate date of commencement of proposed sale of the securities to the public: , 2018.

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box ☐

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and " emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-accelerated Filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act. ☐

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Issuer Tender Offer) ☐

Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer) ☐

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Calculation of Registration Fee

Title of each class of securities to be registered(1)	Amount to be registered(2)	Proposed maximum offering price per share	Proposed maximum aggregate offering price(3)(4)	Amount of registration fee(4)
Common Stock	95,611,418	N/A	$5,078,452,603.75	$632,267.35

(1) This Registration Statement relates to shares of common stock, no par value, of Dominion Energy, Inc. ("Dominion Energy common stock"), issuable to holders of common stock, no par value, of SCANA Corporation ("SCANA common stock") upon completion of the merger described herein.

(2) Represents the estimated maximum number of shares of Dominion Energy common stock to be issued upon completion of the merger described herein. This number is based on 142,916,917 shares of SCANA common stock, the estimated maximum number of shares of SCANA common stock outstanding or reserved for issuance under various equity plans or otherwise, immediately prior to the merger, and the exchange of each such share of SCANA common stock for 0.6690 of a share of Dominion Energy common stock, pursuant to the terms of the Agreement and Plan of Merger, dated as of January 2, 2018, by and among Dominion Energy, Inc., Sedona Corp. and SCANA Corporation, which is attached to the proxy statement/prospectus included in this Registration Statement on Form S-4 as Annex A.

(3) Estimated solely for the purpose of calculating the registration fee required by Section 6(b) of the Securities Act and computed pursuant to Rule 457(f) of the Securities Act. The proposed maximum offering price is equal to the product of (a) $35.5343, the average of the high and low prices of SCANA's common stock reported on the New York Stock Exchange on February 13, 2018 and (b) 142,916,917, the estimated maximum number of shares of SCANA common stock that is expected to be exchanged in connection with the merger described herein.

(4) Computed in accordance with Section 6(b) of the Securities Act by multiplying 0.00012450 by the proposed maximum aggregate offering price.

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The information in this document is not complete and may be changed. Dominion Energy, Inc. may not sell the securities offered by this document until the registration statement filed with the Securities and Exchange Commission, of which this document is a part, is declared effective. This document shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of these securities in any jurisdiction where such offer, solicitation or sale is not permitted.

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PRELIMINARY—SUBJECT TO COMPLETION—DATED , 2018

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MERGER PROPOSED—YOUR VOTE IS VERY IMPORTANT

Dear SCANA Shareholders:

The board of directors of SCANA Corporation, which we refer to as SCANA, has adopted an Agreement and Plan of Merger, which we refer to as the merger agreement, dated as of January 2, 2018, by and among Dominion Energy, Inc., which we refer to as Dominion Energy, Sedona Corp., a wholly owned subsidiary of Dominion Energy, which we refer to as Merger Sub, and SCANA.

Pursuant to the merger agreement, Merger Sub will merge with and into SCANA, which we refer to as the merger, with SCANA surviving the merger as a wholly owned subsidiary of Dominion Energy. In the merger, holders of SCANA common stock, whom we refer to as SCANA shareholders, will have the right to receive 0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock held at the time of the merger, which we refer to as the merger consideration, with cash to be paid in lieu of the issuance of any fractional share of Dominion Energy common stock. The value of the merger consideration to be received in exchange for each share of SCANA common stock will fluctuate with the market value of Dominion Energy common stock. The transaction structure contemplates that the receipt of shares of Dominion Energy common stock will be tax-deferred for SCANA shareholders.

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SCANA shareholders are encouraged to read this entire proxy statement/prospectus carefully, including:

- **the "Questions and Answers About the Merger and the Special Meeting" section beginning on page iv;**
- **the "Risk Factors" section beginning on page 17; and**
- **the "The Merger—SCANA's Reasons for the Merger; Recommendation of the SCANA Board" section beginning on page 47.**

SCANA will hold a special meeting of shareholders to consider the merger, which we refer to as the special meeting. Based on the number of shares of SCANA common stock outstanding on , 2018, the record date for the special meeting, Dominion Energy expects to issue approximately shares of Dominion Energy common stock to the SCANA shareholders. As a result, upon the completion of the merger, former SCANA shareholders will own approximately 13% of the issued and outstanding shares of Dominion Energy common stock. SCANA common stock is listed on the New York Stock Exchange, which we refer to as the NYSE, under the symbol "SCG" and Dominion Energy common stock is listed on the NYSE under the symbol "D."

We cannot complete the merger unless the SCANA shareholders approve the proposal related to the merger and, therefore, your vote is very important. Whether or not you expect to attend the special meeting in person, please vote your shares as promptly as possible by (i) accessing the Internet website specified on your proxy card, (ii) calling the toll-free number specified on your proxy card or (iii) signing all proxy cards that you receive and returning them in the postage-paid envelopes provided, so that your shares of SCANA common stock may be represented and voted at the special meeting. You may change or revoke your proxy at any time before the vote at the special meeting by following the procedures outlined in this proxy statement/prospectus.

We look forward to the successful completion of the merger.

Sincerely,

Jimmy E. Addison
Chief Executive Officer
SCANA Corporation

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of the securities to be issued in connection with the merger or determined that this proxy statement/prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

This proxy statement/prospectus is dated , 2018, and is first being mailed to SCANA shareholders on or about , 2018.

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SCANA CORPORATION

NOTICE OF SPECIAL MEETING OF SHAREHOLDERS TO BE HELD ON , 2018

NOTICE IS HEREBY GIVEN that SCANA Corporation, a South Carolina corporation, which we refer to as SCANA, will hold a special meeting, which we refer to as the special meeting, of the shareholders of SCANA, whom we refer to as SCANA shareholders, on , 2018, at [a.m./p.m.], Eastern Daylight Time, at .

The SCANA shareholders are being asked to consider and vote on the proposals listed below at the special meeting or any adjournment or postponement of the special meeting:

1. the proposal to approve the Agreement and Plan of Merger, dated as of January 2, 2018, by and among Dominion Energy, Inc., a Virginia corporation, which we refer to as Dominion Energy, Sedona Corp., a South Carolina corporation and a wholly owned subsidiary of Dominion Energy, which we refer to as Merger Sub, and SCANA, as such agreement may be amended from time to time, which we refer to as the merger agreement, pursuant to which Merger Sub will be merged with and into SCANA, with SCANA surviving the merger as a wholly owned subsidiary of Dominion Energy, and each outstanding share of the common stock of SCANA, no par value, which we refer to as SCANA common stock, will be converted into the right to receive 0.6690 of a share of the common stock of Dominion Energy, no par value, which we refer to as Dominion Energy common stock, with cash paid in lieu of fractional shares, which we refer to as the merger proposal;

2. the proposal to approve, on a non-binding advisory basis, the compensation to be paid to SCANA's named executive officers that is based on or otherwise relates to the merger, which we refer to as the merger-related compensation proposal; and

3. the proposal to adjourn the special meeting, if necessary or appropriate, in the view of the board of directors of SCANA, which we refer to as the SCANA board, to solicit additional proxies in favor of the merger proposal if there are not sufficient votes at the time of the special meeting to approve the merger proposal, which we refer to as the adjournment proposal.

Approval of the merger proposal by SCANA shareholders is required to complete the merger. Approval of the merger-related compensation proposal and the adjournment proposal are not required to complete the merger.

The SCANA board has unanimously adopted the merger agreement and approved the transactions contemplated thereby, including the merger, and recommends that you vote **"FOR"** the merger proposal, **"FOR"** the merger-related compensation proposal and **"FOR"** the adjournment proposal. Only SCANA shareholders of record at the close of business on , 2018, are entitled to notice of and to vote at the special meeting.

You may vote your shares of SCANA common stock over the Internet at *proxy.georgeson.com*, by calling toll-free [ ], by completing and mailing the enclosed proxy card, or in person at the special meeting. We request that you vote in advance whether or not you plan to attend the special meeting.

If you do not vote on the merger proposal, it will have the same effect as a vote by you against the merger proposal.

You may revoke your proxy at any time prior to the vote at the special meeting by voting your shares of SCANA common stock in person at the special meeting, revoting through the website or telephone numbers listed above, or returning a later-dated proxy card.

Sincerely,

Gina Champion
Vice President, Corporate Secretary and
Deputy General Counsel
, 2018

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ADDITIONAL INFORMATION

This proxy statement/prospectus incorporates important business and financial information about Dominion Energy and SCANA from other documents that Dominion Energy and SCANA have each filed with the U.S. Securities and Exchange Commission, which we refer to as the SEC. For a listing of documents incorporated by reference into this proxy statement/prospectus, please see the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/prospectus. This information is available for you to review at the SEC's public reference room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549, and through the SEC's website at *www.sec.gov*.

This information is available to you without charge upon your request. You can obtain the documents incorporated by reference into this proxy statement/prospectus by requesting them in writing or by telephone from the appropriate company at:

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SCANA Corporation	**Dominion Energy, Inc.**
220 Operation Way, Mail Code C103	120 Tredegar Street
Cayce, South Carolina 29033	Richmond, Virginia 23219
(803) 217-6916	Corporate.Secretary@dominionenergy.com
Attn: Investor Relations	Attn: Corporate Secretary

The firm assisting SCANA with the solicitation of proxies:

Georgeson, Inc.
480 Washington Boulevard
Jersey City, NJ 07310
Shareholders Call Toll-Free: [ ]
Banks and Brokers Call Collect: [ ]
Email: [ ]

Investors may also consult SCANA's or Dominion Energy's website for more information concerning the merger and other related transactions described in this proxy statement/prospectus. SCANA's website is *www.scana.com*. Dominion Energy's website is *www.dominionenergy.com*. Each company's filings with the SEC are also available at *www.sec.gov*. Information contained on SCANA's and Dominion Energy's respective websites is not incorporated by reference into, and does not constitute part of, this proxy statement/prospectus. The references to SCANA's and Dominion Energy's respective websites are intended to be inactive textual references only.

If you would like to request documents, please do so by , 2018 in order to receive them before the special meeting.

For more information, see the section entitled "Where You Can Find More Information" beginning on page 136 of this proxy statement/prospectus.

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ABOUT THIS PROXY STATEMENT/PROSPECTUS

This document, which forms part of a registration statement on Form S-4 filed with the SEC by Dominion Energy (File No. 333-   ), constitutes a prospectus of Dominion Energy under Section 5 of the Securities Act of 1933, as amended, which we refer to as the Securities Act, with respect to the shares of Dominion Energy common stock to be issued to SCANA shareholders pursuant to the merger agreement. This document also constitutes a proxy statement of SCANA under Section 14(a) of the Securities Exchange Act of 1934, as amended, which we refer to as the Exchange Act, with respect to the special meeting at which SCANA shareholders will be asked to vote upon and approve the merger proposal, the non-binding merger-related compensation proposal and the adjournment proposal. It also constitutes a notice of meeting with respect to the special meeting.

You should rely only on the information contained in, or incorporated by reference into, this proxy statement/prospectus. No one has been authorized to provide you with information that is different from that contained in, or incorporated by reference into, this proxy statement/prospectus. This proxy statement/prospectus is dated   , 2018. You should not assume that the information contained in, or incorporated by reference into, this proxy statement/prospectus is accurate as of any date other than, in the case of this proxy statement/prospectus, the date on the front cover of this proxy statement/prospectus and, in the case of information incorporated by reference, the respective dates of such referenced documents. Neither the mailing of this proxy statement/prospectus to SCANA shareholders nor the issuance by Dominion Energy of shares of Dominion Energy common stock in connection with the merger will create any implication to the contrary.

This proxy statement/prospectus does not constitute an offer to sell, or a solicitation of an offer to buy, any securities, or the solicitation of a proxy, in any jurisdiction in which, or from any person to whom, it is unlawful to make any such offer or solicitation in such jurisdiction. Information contained in this proxy statement/prospectus regarding Dominion Energy has been provided by Dominion Energy and information contained in this proxy statement/prospectus regarding SCANA has been provided by SCANA.

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QUESTIONS AND ANSWERS ABOUT THE MERGER AND THE SPECIAL MEETING

The following questions and answers are intended to briefly address some questions that you, as a SCANA shareholder, may have regarding the merger, the merger agreement and the special meeting. Dominion Energy and SCANA urge you to read carefully the remainder of this proxy statement/prospectus because these questions and answers may not address all questions or provide all information that might be important to you with respect to the merger, the merger agreement and the matters being considered at the special meeting. Additional important information is also contained in the annexes and the documents incorporated by reference into this proxy statement/prospectus. You may obtain the information incorporated by reference into this proxy statement/prospectus without charge by following the instructions under the section entitled "Where You Can Find More Information" beginning on page 136 of this proxy statement/prospectus. For your convenience, these questions and answers have been divided into questions and answers about the merger and questions and answers about the special meeting.

Questions and Answers About the Merger

Q: What is the merger?

A: SCANA, Dominion Energy and Merger Sub have entered into the merger agreement, a copy of which is attached as Annex A to this proxy statement/prospectus and is incorporated by reference herein. The merger agreement contains the terms and conditions of the merger, in which Merger Sub will merge with and into SCANA with SCANA surviving the merger as a wholly owned subsidiary of Dominion Energy, which we refer to as the surviving corporation.

Q: Why am I receiving this proxy statement/prospectus and proxy or voting instruction card?

A: SCANA is sending these materials to the SCANA shareholders to help them decide how to vote their shares of SCANA common stock with respect to the merger and other matters to be considered at the special meeting. SCANA is holding the special meeting to ask its shareholders to consider and vote upon the merger proposal. The merger cannot be completed unless SCANA shareholders approve the merger proposal. At the special meeting, SCANA shareholders will also be asked to consider and vote upon (i) the merger-related compensation proposal, on a non-binding, advisory basis and (ii) the adjournment proposal, if necessary or appropriate in the view of the SCANA board.

This proxy statement/prospectus includes important information about the merger, the merger agreement and the special meeting. SCANA shareholders should read this information carefully and in its entirety. The enclosed voting materials allow SCANA shareholders to vote their shares without attending the special meeting in person.

Your vote is very important. We encourage you to vote as soon as possible.

This proxy statement/prospectus constitutes both a proxy statement of SCANA and a prospectus of Dominion Energy. It is a proxy statement of SCANA because the SCANA board is soliciting proxies from the SCANA shareholders. It is a prospectus of Dominion Energy because Dominion Energy will issue shares of Dominion Energy common stock in exchange for outstanding shares of SCANA common stock in the merger.

Q: What will I receive if the merger is completed?

A: If the merger is completed, you will have the right to receive the merger consideration (0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock that you own at the time of the merger). No fractional shares of Dominion Energy common stock will be issued in the merger; instead, if you otherwise would be owed a fraction of a share of Dominion Energy common stock, you will receive the value of that fraction of a share in cash, without interest and rounded to the nearest cent, where value is

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based on a formula that takes into account the volume-weighted average price of Dominion Energy common stock for the ten (10) consecutive trading day period ending on and including the second trading day prior to the time of the closing of the merger. For example, if you own 100 shares of SCANA common stock, in exchange for your shares of Dominion Energy common stock, you will receive 66 shares of Dominion Energy common stock, plus an amount of cash equivalent to the value of 0.90 of a share of Dominion Energy common stock. See the section entitled "*The Merger Agreement—Terms of the Merger*" beginning on page 84 of this proxy statement/prospectus.

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Q: Will my shares of Dominion Energy common stock acquired in the merger receive a dividend?

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A: After the closing of the merger, as a holder of Dominion Energy common stock, you will receive the same dividends on shares of Dominion Energy common stock that all other holders of Dominion Energy common stock will receive with respect to any dividend record date that occurs after the effective time of the merger (as defined below).

Former SCANA shareholders who hold SCANA share certificates will not be entitled to be paid dividends otherwise payable on the shares of Dominion Energy common stock into which their shares of SCANA common stock are exchangeable until they surrender their SCANA share certificates according to the instructions provided to them. Dividends will be accrued for these shareholders and they will receive the accrued dividends when they surrender their SCANA share certificates. Dominion Energy most recently paid a quarterly dividend on December 20, 2017 in an amount equal to $0.770 per share of Dominion Energy common stock. See the section entitled "*Comparative Stock Prices and Dividends*" on page 15 of this proxy statement/prospectus.

All future Dominion Energy dividends will remain subject to approval by the board of directors of Dominion Energy, which we refer to as the Dominion Energy board.

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Q: What will holders of SCANA equity compensation awards receive in the merger?

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A: At the effective time of the merger, each performance share award in respect of SCANA common stock, which we refer to as a performance share award, and restricted stock unit in respect of SCANA common stock, which we refer to as a restricted stock unit, granted under SCANA's 2015 Long-Term Equity Compensation Plan, 2000 Long-Term Equity Compensation Plan, or Director Compensation and Deferral Plan, as applicable, which we collectively refer to as the SCANA equity award plans, will fully vest (at the target level of performance in the case of the performance share awards) and will be cancelled and converted automatically into the right to receive an amount in cash, without interest, based on a formula that takes into account the volume-weighted average price of Dominion Energy common stock for the ten (10) consecutive trading day period ending on and including the second (2nd) trading day prior to the closing of the merger for each share of SCANA common stock underlying such performance share award or restricted stock unit, as applicable.

At the effective time of the merger each deferred unit in respect of SCANA common stock, which we refer to as a deferred unit, credited or deemed credited to the SCANA stock ledger under SCANA's Director Compensation and Deferral Plan or Executive Deferred Compensation Plan shall be converted automatically into a number of deferred unit(s) in respect of Dominion Energy common stock under such plans (which will be assumed by Dominion Energy) equal to the product of (x) such deferred unit multiplied by (y) the merger consideration, to be payable pursuant to the terms of the applicable plan.

For additional information regarding the SCANA equity compensation awards, see the section entitled "*The Merger—Interests of SCANA's Directors and Executive Officers in the Merger—Equity Compensation*" beginning on page 73 of this proxy statement/prospectus.

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Q: Do any of SCANA's directors or executive officers have interests in the merger that may differ from or be in addition to my interests as a SCANA shareholder?

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A: In considering the recommendation of the SCANA board with respect to the merger proposal, you should be aware that SCANA's directors and executive officers may have interests in the merger that are different

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from, or in addition to, the interests of the SCANA shareholders generally. The SCANA board was aware of and considered these interests, among other matters, in evaluating and negotiating the merger agreement and the merger, and in recommending that the SCANA shareholders approve the merger agreement. For additional information on the interests of SCANA's directors and executive officers in the merger, see the section entitled "*The Merger—Interests of SCANA's Directors and Executive Officers in the Merger*" beginning on page 72 of this proxy statement/prospectus and "*Non-Binding Advisory Vote on Named Executive Officer Merger-Related Compensation*" beginning on page 110 of this proxy statement/prospectus.

Q: Why am I being asked to consider and vote on the merger-related compensation proposal?

A: Under SEC rules, we are required to conduct a non-binding advisory vote of shareholders regarding the compensation that may be paid or become payable to our named executive officers in connection with the completion of the merger.

Q: What will happen if the SCANA shareholders do not approve the merger-related compensation proposal?

A: Approval of the merger-related compensation proposal is not a condition to completion of the merger. The merger-related compensation vote is advisory and will not be binding. Therefore, if the merger proposal is approved by the SCANA shareholders and the merger is completed, the compensation that is the subject of the merger-related compensation proposal, which includes amounts we are contractually obligated to pay, would still be paid regardless of the outcome of the non-binding advisory vote.

Q: If I do not favor the approval of the merger agreement, do I have appraisal or dissenters' rights?

A: No. Because SCANA common stock is listed on the NYSE as of the record date of the special meeting, holders of SCANA common stock are not entitled to exercise appraisal or dissenters' rights under Section 33-13-102(B) of the South Carolina Business Corporation Act, which we refer to as the SCBCA, in connection with the merger. SCANA shareholders may vote against the merger proposal if they are not in favor of the approval of the merger agreement. For additional information on appraisal or dissenters' rights, see the section entitled "*The Merger—No Dissenters' Rights*" beginning on page 67 of this proxy statement/prospectus.

Q: What are the U.S. federal income tax consequences of the merger to SCANA shareholders?

A: The merger is intended to be non-taxable to SCANA shareholders, provided it qualifies as a "reorganization" within the meaning of Section 368(a) of the Internal Revenue Code of 1986, as amended, which we refer to as the Code. The holders of SCANA common stock are not expected to recognize any gain or loss for U.S. federal income tax purposes on the exchange of shares of SCANA common stock for shares of Dominion Energy common stock in the merger, except with respect to any cash received in lieu of fractional shares of Dominion Energy common stock.

You should read "*The Merger—U.S. Federal Income Tax Consequences of the Merger*" beginning on page 65 of this proxy statement/prospectus for a more complete discussion of the U. S. federal income tax consequences of the merger. Tax matters can be complicated and the tax consequences of the merger to you will depend on your particular tax situation. You should consult your tax advisor to determine the tax consequences of the merger to you.

Q: What will happen to SCANA as a result of the merger?

A: If the merger is completed, Merger Sub will be merged with and into SCANA, with SCANA continuing as the surviving corporation and a wholly owned subsidiary of Dominion Energy.

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SCANA will no longer be a public company, and its shares will be delisted from the NYSE, deregistered under the Exchange Act and cease to be publicly traded. SCANA shareholders of record at the effective time of the merger will be entitled to receive the merger consideration.

Q: What equity stake will SCANA shareholders hold in Dominion Energy immediately following the merger?

A: We estimate that upon the closing of the merger, holders of SCANA common stock will hold, in the aggregate, approximately 13% of the issued and outstanding shares of Dominion Energy common stock.

Q: When do you expect the merger to be completed?

A: We hope to complete the merger in 2018; however, the merger is subject to various regulatory approvals and other conditions set forth in the merger agreement and described elsewhere in this proxy statement/prospectus and it is possible that factors outside the control of SCANA and Dominion Energy could result in the merger being completed at a later time, or not at all. There may be a substantial amount of time between the special meeting and the completion of the merger. We hope to complete the merger as soon as reasonably practicable following the receipt of all required approvals and the satisfaction or waiver of the other conditions.

Q: What are the conditions to the completion of the merger?

A: In addition to the approval of the merger agreement by SCANA shareholders as described above, closing of the merger is subject to the satisfaction or, to the extent permitted by applicable law, waiver of a number of other conditions, including compliance with applicable federal and state regulatory filing and approval requirements under the terms of the merger agreement, including under the Hart-Scott-Rodino Act, which we refer to as the HSR Act, and from the Nuclear Regulatory Commission, which we refer to as the NRC, and the Federal Energy Regulatory Commission, which we refer to as FERC, as well as from the Public Service Commission of South Carolina, the North Carolina Utilities Commission and the Georgia Public Service Commission, which we refer to as SCPSC, NCUC and GPSC, respectively. Other conditions include that, since the date of the merger agreement, there have been no substantive changes in any applicable law or order with respect to the South Carolina Base Load Review Act of 2007, as amended, which we refer to as the BLRA, or other South Carolina public utility laws that have or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries and that no governmental entity of competent jurisdiction shall have entered any order or enacted any change in law that imposes any condition that would reasonably be expected to result in any material change to the proposed terms, conditions or undertakings of the SCPSC petition (as defined in "*Summary—Conditions to Completion of the Merger*") or any significant change to the economic value of the proposed terms of the SCPSC petition, in each case as reasonably determined by Dominion Energy in good faith. Further conditions to closing include (1) that the SCPSC approve the SCPSC petition (other than the request for the SCPSC to make the SCPSC merger determination (as defined below)), unless otherwise consented to by Dominion Energy in its sole discretion, without any material change to the terms, conditions or undertakings of the cost recovery plan (as defined below) or any significant change to the economic value of the cost recovery plan, in each case as reasonably determined by Dominion Energy in good faith, and (2) that the SCPSC approve the merger with no material changes to the terms of the merger or make a finding that the merger is in the public interest or make a finding that there is an absence of harm to South Carolina rate payers as a result of the merger. We refer to the condition in clause (2) as the SCPSC merger determination.

For a more complete summary of these conditions and additional conditions that must be satisfied or waived prior to the closing of the merger, see the section entitled "*The Merger Agreement—Conditions to Completion of the Merger*" beginning on page 88 of this proxy statement/prospectus.

Q: What happens if I sell my shares of SCANA common stock before the special meeting?

A: The record date for SCANA shareholders entitled to vote at the special meeting is , 2018, which is earlier than the date of the special meeting. If you sell or otherwise transfer your shares of SCANA

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common stock after the record date but before the special meeting, you will retain your right to vote such shares at the special meeting but will otherwise transfer ownership of your shares of SCANA common stock, unless special arrangements (such as provision of a proxy) are made between you and the person to whom you transfer your shares and each of you notifies us in writing of such special arrangements.

Q: What happens if I sell or otherwise transfer my shares of SCANA common stock before the completion of the merger?

A: Only holders of shares of SCANA common stock at the time the articles of merger have been filed with the South Carolina Secretary of State (unless the parties agree in writing to a later time for the completion of the merger and specify such time in the articles of merger), which we refer to as the effective time of the merger, will become entitled to receive the merger consideration. If you sell your shares of SCANA common stock prior to the completion of the merger, you will not be entitled to receive the merger consideration upon completion of the merger.

Q: What happens if the merger is not completed?

A: Under the terms of the merger agreement, if the conditions to the merger are not satisfied or waived by January 2, 2019, which we refer to as the termination date (which will automatically be extended to April 2, 2019 if on the termination date certain required regulatory approvals have not been obtained), then either SCANA or Dominion Energy may terminate the merger agreement, subject to certain restrictions. The merger agreement can also be terminated under other circumstances specified under the merger agreement (see the section entitled "*The Merger Agreement—Termination of the Merger Agreement*" beginning on page 99 of this proxy statement/prospectus). Under specified circumstances, SCANA may be required to pay to Dominion Energy, or be entitled to receive from Dominion Energy, a fee with respect to the termination of the merger agreement. See the section entitled "*The Merger Agreement—Termination Fees*" beginning on page 100.

We cannot complete the merger unless the SCANA shareholders approve the merger proposal. If the merger agreement is not approved by SCANA shareholders or if the merger is not completed for any other reason, SCANA will remain an independent company, the SCANA shareholders will not receive any merger consideration for their shares of SCANA common stock in connection with the merger, and the shares of SCANA common stock will remain outstanding and will continue to be listed and traded on the NYSE.

Questions and Answers Regarding the Special Meeting and Voting

Q: When and where will the special meeting be held?

A: The special meeting will be held at [a.m./p.m.], Eastern Daylight Time on , 2018 at .

Q: What matters will be voted on at the special meeting?

A: You will be asked to consider and vote on the following proposals:

- the merger proposal;
- the merger-related compensation proposal; and
- the adjournment proposal.

SCANA will transact no other business at the special meeting or any adjournment or postponement thereof.

Q: What vote is required for approval of the proposals?

A:
- Approval of the merger proposal requires the affirmative vote of the holders of at least two-thirds of the outstanding shares of SCANA common stock;

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- The merger-related compensation proposal will be approved if more votes are cast in favor of the proposal than against the proposal (the outcome of the merger-related compensation proposal will not be binding on SCANA or the SCANA board or the compensation committee of the SCANA board); and
- The adjournment proposal will be approved if more votes are cast in favor of the proposal than against the proposal.

Q: How does the SCANA board recommend that I vote on the proposals?

A: The SCANA board recommends that the SCANA shareholders vote (i) **"FOR"** the merger proposal, (ii) **"FOR"** the merger-related compensation proposal and (iii) **"FOR"** the adjournment proposal.

Q: Who is entitled to vote at the special meeting?

A: All holders of SCANA common stock as of the close of business on   , 2018, the record date for the special meeting, are entitled to vote at the special meeting, unless a new record date is fixed for any adjournment or postponement of the special meeting.

Q: What are the quorum requirements?

A: A quorum requires the presence, in person or by proxy, of the holders of a majority of the shares of SCANA common stock outstanding and entitled to vote. A quorum is needed to conduct the votes on the merger proposal and the merger-related compensation proposal. Abstentions and broker "non-votes," if any, will be counted as present and entitled to vote for purposes of determining the presence or absence of a quorum.

Q: How can I attend the special meeting in person?

A: An admission ticket or proof of share ownership as of the record date is required to attend the special meeting in person. If you plan to use the admission ticket, please remember to detach the admission ticket from your proxy card before mailing your proxy card. If you forget to bring the admission ticket, you will be admitted to the special meeting only if you are listed as a shareholder of record as of the record date and you bring proof of identification. If you hold your shares through a broker, bank or other nominee, you must provide proof of ownership by bringing either a copy of the voting instruction card provided by your broker, bank or other nominee or a brokerage statement showing your share ownership as of the record date. If you are a SCANA shareholder of record and your shares are owned jointly and you need an additional admission ticket, you should contact the SCANA Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033, or call 803-217-7568.

Q: How do I vote?

A: If you are a SCANA shareholder of record as of the record date for the special meeting, whether or not you plan to attend the special meeting, you may vote by submitting a proxy via the Internet, touchtone telephone or mail before the special meeting, or you may vote in person at the special meeting. To ensure your shares are represented at the special meeting, you may submit your proxy by:

- accessing *proxy.georgeson.com* (this Internet website is specified on your proxy card);
- calling   (this toll-free number is specified on your proxy card); or
- signing and returning the enclosed proxy card in the postage-paid envelope provided.

If you hold shares of SCANA common stock through a broker, bank or other nominee, please follow the voting instructions provided by your broker, bank or other nominee to ensure that your shares are represented at the special meeting.

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Q: How many votes do I have?

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A: You are entitled to one (1) vote for each share of SCANA common stock that you owned as of the record date. As of the close of business on , 2018, there were outstanding shares of SCANA common stock.

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Q: What will happen if I fail to vote or I abstain from voting?

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A: You are strongly encouraged to vote. It is important that your views be represented no matter how many shares you own. Your failure to vote, or failure to instruct your broker, bank or other nominee to vote, or your abstention from voting, will have the same effect as a vote against the merger proposal, but will not be counted as a vote "for" or "against" the merger-related compensation proposal or the adjournment proposal.

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Q: Who is SCANA's transfer agent?

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A: Wells Fargo Shareowner Services, a division of Wells Fargo Bank, N.A., which we refer to as Shareowner Services, has served as the transfer agent and registrar for SCANA. On July 12, 2017, Wells Fargo Bank, N.A. announced that it had entered into an agreement to sell Shareowner Services to Equiniti Group plc. In connection with the sale of Shareowner Services, its appointment as transfer agent of SCANA will be transferred to Equiniti Trust Company, which we refer to as EQ, provided that the sale closes. Accordingly, following the closing of the sale, EQ will serve as the transfer agent and registrar for SCANA common stock.

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Q: What is the difference between holding shares as a shareholder of record and as a beneficial owner?

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A: If your shares of SCANA common stock are registered directly in your name with SCANA's transfer agent, you are considered the shareholder of record with respect to those shares and you can attend the special meeting and vote in person. You can also vote your shares by proxy without attending the special meeting in any of the ways specified in "*The Special Meeting—Voting by Proxy*" beginning on page 31 of this proxy statement/prospectus.

If your shares of SCANA common stock are held by a brokerage firm, trustee, bank, other financial intermediary or nominee, referred to as an intermediary, you are considered the beneficial owner of shares held in "street name," and the intermediary is considered the shareholder of record with respect to those shares.

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Q: How do I vote my shares of SCANA common stock if my shares are held in "street name" by my broker, bank or other nominee?

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A: If your shares of SCANA common stock are held in "street name" (that is, through a broker, bank or other nominee), you will receive a voting instruction card or other information from your broker, bank or other nominee seeking instruction from you as to how your shares should be voted, and, to vote your shares, you must provide your broker, bank or other nominee with instructions on how to vote them. Please follow the voting instructions provided by your broker, bank or other nominee. Please note that you may not vote shares held in "street name" by returning a proxy card directly to SCANA or by voting in person at the special meeting unless you provide a "legal proxy," which you must obtain from your broker, bank or other nominee.

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Q: If my shares of SCANA common stock are held in "street name," what will happen if I do not instruct my broker, bank or other nominee on how to vote?

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A: If you do not instruct your broker, bank or other nominee on how to vote your shares:

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- your broker, bank or other nominee may not vote your shares on the merger proposal, which broker non-votes will have the same effect as a vote against the merger proposal;

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- your broker, bank or other nominee may not vote your shares on the merger-related compensation proposal, which broker non-votes will not be counted as a vote "for" or "against" the merger-related compensation proposal; and
- your broker, bank or other nominee may not vote your shares on the adjournment proposal, which broker non-votes will not be counted as a vote "for" or "against" the adjournment proposal.

Q: If I am a shareholder of record, what will happen if I sign and return my proxy card without indicating how to vote?

A: If you sign and return your proxy card without indicating how to vote on any particular proposal, the SCANA common stock represented by your proxy will be voted in favor of that proposal.

Q: How do I vote shares I hold as a participant in the SCANA Corporation 401(k) Retirement Savings Plan (formerly named the SCANA Corporation Stock Purchase-Savings Plan)?

A: If you own shares of SCANA common stock as a participant in the SCANA Corporation 401(k) Retirement Savings Plan, which we refer to as the Plan, you will receive a proxy card that covers only your Plan shares. Proxies executed by Plan participants will serve as instructions to the Plan's trustee as to how Plan shares are to be voted. If you do not instruct the Plan's trustee how your Plan shares are to be voted, the Plan trustee will instruct the proxy agents to vote your shares in the same proportion as the Plan shares for which the Plan's trustee received instructions were voted. As a result of this proportional voting, if voting instructions are given for only a small percentage of Plan participant shares, the wishes of those participants would determine the voting instructions by the Plan's trustee. Accordingly, the greater the number of Plan participant shares for which Plan participants complete and execute proxies, the more representative the Plan trustee's voting instructions will be.

The deadline to provide voting directions for shares allocated to your Plan account in the Plan is   [a.m./p.m.], Eastern Daylight Time on   , 2018, which, for administrative reasons, is earlier than the deadline for voting SCANA common stock not held through the Plan. You will not be able to submit or change voting directions after this deadline. If you own SCANA common stock both through and outside of the Plan, you will be required to vote those shares separately.

Q: May I change my vote after I have returned a proxy or voting instruction card?

A: Yes. You may change your vote (i.e., revoke your proxy card) at any time before your proxy is voted at the special meeting. If you are a shareholder of record (i.e., you hold your shares directly in your name), you may accomplish this by granting a new proxy (by telephone, Internet or mail) bearing a later date or by attending the special meeting and voting in person (each of which automatically revokes the earlier proxy). However, your attendance at the special meeting alone will not revoke any proxy that you have previously given. If you hold your shares in "street name," you must follow the instructions on the voting instruction card you received from your broker, bank or other nominee in order to change or revoke your instructions.

Q: What do I need to do now?

A: Carefully read and consider the information contained in and incorporated by reference into this proxy statement/prospectus, including its annexes.

In order for your shares to be represented at the special meeting:

- you can vote through the Internet or by telephone by following the instructions included on your proxy card;
- you can indicate on the enclosed proxy card how you would like to vote and return the card in the accompanying pre-addressed postage paid envelope; or
- you can attend the special meeting in person.

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Q: Do I need to do anything with my SCANA common stock certificates now?

A: No. If and after the merger is completed, if you held certificates representing shares of SCANA common stock, which we refer to as SCANA stock certificates, prior to the merger, Dominion Energy's exchange agent will send you a letter of transmittal and instructions for exchanging your SCANA stock certificates for the merger consideration. Upon surrender of the SCANA stock certificates for cancellation along with the executed letter of transmittal and other required documents described in the instructions, you will receive the merger consideration. The shares of Dominion Energy common stock you receive in the merger will be issued in book-entry form.

Q: Who will solicit and pay the cost of soliciting proxies?

A: SCANA has engaged Georgeson, Inc. to assist in the solicitation of proxies for the special meeting, and will pay an estimated fee of $ for their services plus associated costs and expenses.

Q: Who can help answer my questions?

A: If you have questions about the merger or the other matters to be voted on at the special meeting or desire additional copies of this proxy statement/prospectus or additional proxy cards, you should contact our proxy solicitor or our shareholder services provider:

Georgeson, Inc.
480 Washington Boulevard,
Jersey City, NJ 07310
Shareholders Call Toll-Free: [ ]
Banks and Brokers Call Collect: [ ]
Email: [ ]
or
[ ]
[ ]
Telephone: [ ]
Email: [ ]

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SUMMARY

This summary highlights information contained elsewhere in this proxy statement/prospectus and may not contain all the information that is important to you. We urge you to read carefully the remainder of this proxy statement/prospectus, including the attached annexes, and the other documents to which we have referred you for a more complete understanding of the matters being considered at the special meeting. See also the section entitled "Where You Can Find More Information" on page 136 of this proxy statement/prospectus. We have included page references to direct you to a more complete description of the topics presented in this summary.

Parties to the Merger

Dominion Energy

120 Tredegar Street
Richmond, Virginia 23219
(804) 819-2000

Headquartered in Richmond, Virginia and incorporated in Virginia in 1983, Dominion Energy is one of the nation's largest producers and transporters of energy, with a portfolio of approximately 26,000 megawatts of electric generation, 66,100 miles of natural gas transmission, gathering, storage and distribution pipelines and 64,500 miles of electric transmission and distribution lines. Dominion Energy operates one of the largest natural gas storage systems in the U.S. with 1 trillion cubic feet of capacity, and serves nearly 6 million utility and retail energy customers.

Dominion Energy common stock is listed on the NYSE under the symbol "D."

Additional information about Dominion Energy is included in the documents incorporated by reference into this proxy statement/prospectus. See the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/prospectus.

SCANA

100 SCANA Parkway
Cayce, South Carolina 29033
(803) 217-9000

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA, through its wholly owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in the central, southern and southwestern portions of South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. SCANA, through a wholly owned nonregulated subsidiary, also markets natural gas to retail customers in Georgia and to wholesale customers in the southeast United States.

SCANA common stock is traded on the NYSE under the symbol "SCG."

Additional information about SCANA and its subsidiaries is included in the documents incorporated by reference into this proxy statement/prospectus. See the section entitled "*Where You Can Find More Information*" on page 136 of this proxy statement/prospectus.

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Merger Sub

120 Tredegar Street
Richmond, Virginia 23219
(804) 819-2000

Merger Sub, a wholly owned subsidiary of Dominion Energy, is a South Carolina corporation formed on December 29, 2017 for the purpose of effecting the merger. To date, Merger Sub has not conducted any activities other than those incidental to its formation and the matters contemplated by the merger agreement in connection with the merger.

The Merger and the Merger Agreement

The terms and conditions of the merger are contained in the merger agreement, a copy of which is attached as Annex A to this proxy statement/prospectus. We encourage you to carefully read the merger agreement in its entirety, as it is the principal document that governs the merger.

Pursuant to and in accordance with the terms and conditions of the merger agreement, at the effective time of the merger, Merger Sub will merge with and into SCANA. After the effective time of the merger, SCANA will be the surviving corporation and a wholly owned subsidiary of Dominion Energy. Following the effective time of the merger, SCANA common stock will be delisted from the NYSE, deregistered under the Exchange Act, and cease to be publicly traded.

Merger Consideration (See page 84)

Upon completion of the merger, each issued and outstanding share of SCANA common stock (other than shares owned by Dominion Energy, Merger Sub or any other wholly owned subsidiary of Dominion Energy and shares owned by SCANA or any wholly owned subsidiary of SCANA, which shares we refer to as cancelled shares) will be automatically converted into the right to receive the merger consideration. Cash will be paid in lieu of any fractional shares of Dominion Energy common stock.

Recommendations of the SCANA Board of Directors (See page 47)

On January 2, 2018 the SCANA board adopted the merger agreement by a unanimous vote. For the factors considered by the SCANA board in reaching its decision to approve the merger agreement, see the section entitled "*The Merger—SCANA's Reasons for the Merger; Recommendation of the SCANA Board*" beginning on page 42.

The SCANA board recommends that the SCANA shareholders vote (i) "FOR" the merger proposal, (ii) "FOR" the merger-related compensation proposal and (iii) "FOR" the adjournment proposal.

Opinions of SCANA's Financial Advisors (See page 47)

Opinion of Morgan Stanley & Co. LLC (See page 47)

The SCANA board selected Morgan Stanley & Co. LLC, which we refer to as Morgan Stanley, to act as its financial advisor based on Morgan Stanley's qualifications, expertise and reputation, its knowledge of and involvement in recent transactions in SCANA's industry and its knowledge and understanding of the business and affairs of SCANA. On January 2, 2018, Morgan Stanley rendered its oral opinion, which was subsequently confirmed in writing, to the SCANA board to the effect that, as of that date, and based upon and subject to the assumptions made, procedures followed, matters considered and qualifications and limitations on the scope of

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review undertaken by Morgan Stanley as set forth in Morgan Stanley's written opinion, the merger consideration to be received by the holders of shares of SCANA common stock (other than the holders of the cancelled shares) pursuant to the merger agreement was fair from a financial point of view to the holders of shares of SCANA common stock.

The full text of the written opinion of Morgan Stanley delivered to the SCANA board, dated January 2, 2018, is attached as Annex B and incorporated into this proxy statement/prospectus by reference in its entirety. The opinion sets forth, among other things, the assumptions made, procedures followed, matters considered and qualifications and limitations on the scope of the review undertaken by Morgan Stanley in rendering its opinion. SCANA shareholders are urged to, and should, read the opinion carefully and in its entirety. Morgan Stanley's opinion is directed to the SCANA board and addresses only the fairness from a financial point of view of the merger consideration to be received by the holders of shares of SCANA common stock (other than the holders of the cancelled shares) pursuant to the merger agreement as of the date of the opinion. Morgan Stanley's opinion did not address the relative merits of the transactions contemplated by the merger agreement as compared to other business or financial strategies that might be available to SCANA, nor did it address the underlying business decision of SCANA to enter into the merger agreement or proceed with any other transaction contemplated by the merger agreement. In addition, Morgan Stanley's opinion did not in any manner address the prices at which shares of Dominion Energy common stock will trade following completion of the merger or at any time, and Morgan Stanley's opinion was not intended to, and does not, express any opinion or recommendation as to how the SCANA shareholders should vote at the special meeting. The summary of Morgan Stanley's opinion set forth in this proxy statement/prospectus is qualified in its entirety by reference to the full text of Morgan Stanley's opinion.

For a summary of Morgan Stanley's opinion and the methodology that Morgan Stanley used to render its opinion, see the section entitled "*The Merger—Opinions of SCANA's Financial Advisors—Opinion of Morgan Stanley & Co. LLC*" beginning on page 47 of this proxy statement/prospectus.

Opinion of RBC Capital Markets, LLC (See page 58)

SCANA has engaged RBC Capital Markets, LLC, which we refer to as RBC Capital Markets, as a financial advisor to SCANA in connection with the merger. As part of this engagement, RBC Capital Markets delivered an opinion, dated January 2, 2018, to the SCANA board as to the fairness, from a financial point of view and as of such date, of the merger consideration to be received by holders of SCANA common stock pursuant to the merger agreement. The full text of RBC Capital Markets' written opinion, dated January 2, 2018, is attached as Annex C to this proxy statement/prospectus and sets forth, among other things, the procedures followed, assumptions made, factors considered and qualifications and limitations on the review undertaken by RBC Capital Markets in connection with its opinion, as more fully described in the section entitled "*The Merger—Opinions of SCANA's Financial Advisors—Opinion of RBC Capital Markets, LLC*" beginning on page 58 of this proxy statement/prospectus. **RBC Capital Markets delivered its opinion to the SCANA board for the benefit, information and assistance of the SCANA board (in its capacity as such) in connection with its evaluation of the merger. RBC Capital Markets' opinion addressed only the fairness, from a financial point of view and as of the date of such opinion, of the merger consideration (to the extent expressly specified in such opinion) and did not address any other aspect of the merger. RBC Capital Markets' opinion also did not address the underlying business decision of SCANA to engage in the merger or the relative merits of the merger compared to any alternative business strategy or transaction that might be available to SCANA or in which SCANA might engage. RBC Capital Markets does not express any opinion and does not make any recommendation to any shareholder as to how such shareholder should vote or act with respect to the merger or any proposal to be voted upon in connection with the merger or otherwise.**

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Interests of SCANA's Directors and Executive Officers in the Merger (See page 72)

In considering the recommendation of the SCANA board with respect to the merger proposal and the other information contained in this proxy statement/prospectus, you should be aware that SCANA's executive officers and directors may have interests in the merger that may be different from, or in addition to, the interests of the SCANA shareholders. These interests include the accelerated vesting of equity awards, arrangements that provide for severance benefits if the employment of a SCANA executive officer is terminated under specified circumstances following the completion of the merger and rights to indemnification and director's and officer's liability insurance that will survive the completion of the merger. For a detailed discussion of the interests that SCANA's directors and executive officers may have in the merger, please see the section entitled "*The Merger—Interests of SCANA's Directors and Executive Officers in the Merger*" beginning on page 72 of this proxy statement/prospectus.

Expected Timing of the Merger (See page 68)

We are targeting to complete the merger in 2018, subject to the receipt of required shareholder and regulatory approvals and the satisfaction or waiver of the other conditions to the merger discussed below.

Conditions to Completion of the Merger (See page 88)

As more fully explained below, the obligation of SCANA, Dominion Energy and Merger Sub to effect the merger is subject to the satisfaction or waiver of the following mutual conditions:

- the receipt of the affirmative vote of holders of at least two-thirds of the outstanding shares of SCANA common stock entitled to vote thereon at a duly held special meeting (or any adjournment or postponement of the special meeting) with respect to the merger proposal, which we refer to as the SCANA requisite vote;
- the absence of any law or order issued by any governmental entity (as defined below) prohibiting the completion of the merger;
- the expiration or termination of the waiting period applicable to the completion of the merger under the HSR Act;
- authorization of the merger from the FERC;
- authorization of the merger from the NRC;
- authorization of the merger from the GPSC;
- authorization of the merger from the NCUC;
- the issuance by the SCPSC of an order approving the SCPSC petition (other than with respect to the SCPSC merger determination, which is discussed in the conditions of Dominion Energy and Merger Sub in the immediately following paragraph), unless otherwise consented to by Dominion Energy in its sole discretion, without any material changes to the proposed terms, conditions or undertakings set forth in the cost recovery plan or any significant changes to the economic value of the proposed terms of the cost recovery plan (we refer to (i) the South Carolina Public Service Authority as Santee Cooper, (ii) the New Nuclear Development Project under which SCANA and Santee Cooper undertook to construct two (2) Westinghouse AP1000 Advanced Passive Safety nuclear units in Jenkinsville, South Carolina as the NND project, (iii) the cost recovery plan set forth in the SCPSC petition as the cost recovery plan and (iv) the joint petition filed by SCANA's wholly owned utility subsidiary South Carolina Electric & Gas Company, which we refer to as SCE&G, and Dominion Energy with the SCPSC requesting that the SCPSC approve the merger and approve the terms for cost recovery and other regulatory matters with respect to the NND project set forth therein as the SCPSC petition);

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- the approval for listing of the shares of Dominion Energy common stock to be issued in the merger on the NYSE; and
- the effectiveness under the Securities Act of the registration statement on Form S-4 of which this proxy statement/prospectus is a part.

The obligation of Dominion Energy and Merger Sub to effect the merger is subject to the satisfaction or waiver of the following additional conditions:

- the representations and warranties of SCANA relating to SCANA's capitalization being true and correct in all respects, except for de minimis inaccuracies;
- the representations and warranties of SCANA relating to (i) SCANA's authority to execute and deliver the merger agreement and perform its obligations under the merger agreement and (ii) broker's and advisor's fees and commissions owed by SCANA to brokers or other financial advisors in connection with the merger, each being true and correct in all material respects;
- the representations and warranties of SCANA relating to (i) the absence of any changes since January 1, 2017 that have or would be reasonably expected to have, individually or in the aggregate, a material adverse effect on SCANA and its subsidiaries, taken as a whole and (ii) the SCANA requisite vote being the only vote of the SCANA shareholders required to approve the merger agreement and the merger, each being true and correct in all respects;
- each of the representations and warranties of SCANA other than those referred to in the three immediately preceding bullets being true and correct in all respects, except where the failure of such representations and warranties to be true and correct has not had or would not be reasonably expected to have, individually or in the aggregate, a material adverse effect on SCANA and its subsidiaries, taken as a whole;
- performance in all material respects by SCANA of all obligations required to be performed by it under the merger agreement on or prior to the closing date of the merger;
- Dominion Energy having received a certificate of the chief executive officer or the chief financial officer of SCANA, certifying that the conditions set forth in the five (5) immediately preceding bullets have been satisfied;
- the absence of any regulatory approval or other approval or consent, in each case in connection with the merger, or order of a governmental entity related to any of the foregoing imposing a burdensome condition;
- the absence of any changes since the date of the merger agreement that have or would be reasonably expected to have, individually or in the aggregate, a material adverse effect on SCANA and its subsidiaries, taken as a whole;
- the absence of any order enacted by a governmental entity of competent jurisdiction or any change in law which, in each case, imposes any condition that would reasonably be expected to result in (i) a material change to the proposed terms, conditions, or undertakings set forth in the SCPSC petition, or (ii) a significant change to the economic value of the proposed terms set forth in the SCPSC petition, in each case as reasonably determined by Dominion Energy in good faith;
- the SCPSC shall have made the SCPSC merger determination; and
- the absence of any (i) substantive change in applicable law or any order with respect to the BLRA as in effect as of the date of the merger agreement or (ii) substantive change in any applicable law or any order enacted by a governmental entity with respect to any other laws of the State of South Carolina governing public utilities as in effect as of the date of the merger agreement, in each case, which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries.

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The obligation of SCANA to effect the merger is subject to the satisfaction or waiver of the following additional conditions:

- the representations and warranties of Dominion Energy and Merger Sub relating to Dominion Energy's and Merger Sub's capitalization being true and correct in all respects, except for *de minimis* inaccuracies;
- the representations and warranties of Dominion Energy and Merger Sub relating to (i) Dominion Energy's and Merger Sub's authority to execute and deliver the merger agreement and perform its obligations under the merger agreement and (ii) broker's and advisor's fees and commissions owed by Dominion Energy and Merger Sub to brokers or other financial advisors in connection with the merger, each being true and correct in all material respects;
- the representations and warranties of Dominion Energy and Merger Sub relating to (i) the absence of any change since January 1, 2017 that has or would be reasonably expected to have, individually or in the aggregate, a material adverse effect on Dominion Energy and its subsidiaries, taken as a whole and (ii) the approval of the merger agreement by the sole shareholder of Merger Sub being the only vote or consent of any class of capital stock of Dominion Energy or any of its affiliates necessary for Dominion Energy and Merger Sub to approve the merger agreement and complete the merger and the other transactions contemplated by the merger agreement, each being true and correct in all respects;
- each of the representations and warranties of Dominion Energy and Merger Sub other than those referred to in the three (3) immediately preceding bullets above being true and correct in all respects, except where the failure of such representations and warranties to be true and correct has not had or would not be reasonably expected to have, individually or in the aggregate, a material adverse effect on Dominion Energy and its subsidiaries, taken as a whole;
- performance in all material respects by Dominion Energy and Merger Sub of all obligations required to be performed by them under the merger agreement on or prior to the closing date of the merger; and
- SCANA having received a certificate of the chief executive officer or the chief financial officer of Dominion Energy certifying that the conditions set forth in the five (5) immediately preceding bullets have been satisfied.

We cannot be certain when, or if, the conditions to the merger will be satisfied or waived, or that the merger will be completed.

Termination of the Merger Agreement (See page 99)

As more fully explained below, the merger agreement may be terminated and the merger may be abandoned at any time prior to the effective time of the merger:

- by mutual written consent of Dominion Energy and SCANA;
- by either Dominion Energy or SCANA:
  - if the merger shall not have been completed on or before January 2, 2019, except that such date will be automatically extended to April 2, 2019 if, as of January 2, 2019, the only conditions to closing not yet satisfied or waived are the ones relating to governmental orders, regulatory approvals or the SCPSC's approval of the cost recovery plan;
  - if the SCANA requisite vote is not obtained at the special meeting (or any adjournment or postponement thereof); or
  - if a governmental entity shall have entered a final, nonappealable order that prohibits completion of the merger;

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- by SCANA:
  - if, prior to obtaining the SCANA requisite vote, the SCANA board has effected a SCANA board adverse recommendation change with respect to a superior proposal in accordance with the procedures set forth in the merger agreement and shall have approved, and concurrently with the termination of the merger agreement, SCANA shall have entered into, an alternative acquisition agreement with respect to a superior proposal and paid to Dominion Energy the applicable termination fee; or
  - if Dominion Energy or Merger Sub have breached any of their respective representations or warranties or failed to perform any of their respective covenants under the merger agreement where (i) such breach would give rise to a failure of a condition to SCANA's obligation to complete the merger relating to (a) the accuracy of Dominion Energy's and Merger Sub's representations and warranties or (b) the performance by Dominion Energy and Merger Sub of all obligations required to be performed by them under the merger agreement and (ii) the breach cannot be cured by Dominion Energy or Merger Sub prior to the termination date, or is not cured by Dominion Energy or Merger Sub prior to the earlier of (a) the thirtieth (30th) day after SCANA provides Dominion Energy written notice of such breach and (b) the third (3rd) business day immediately preceding the termination date;
- by Dominion Energy:
  - if the SCANA board (or a committee thereof) has effected a SCANA board adverse recommendation change; or
  - if SCANA has breached any of its representations or warranties or failed to perform any of its covenants under the merger agreement where (i) such breach would give rise to a failure of a condition to Dominion Energy's and Merger Sub's obligation to complete the merger relating to (a) the accuracy of SCANA's representations and warranties or (b) the performance by SCANA of all obligations required to be performed by it under the merger agreement and (ii) the breach cannot be cured by SCANA prior to the termination date, or is not cured by SCANA prior to the earlier of (a) the thirtieth (30th) day after Dominion Energy provides SCANA written notice of such breach and (b) the third (3rd) business day immediately preceding the termination date.

Termination Fees (See page 100)

The merger agreement provides that, upon termination of the merger agreement under certain circumstances, each party may be obligated to pay the other party a termination fee, discussed under the section entitled "*The Merger Agreement—Termination Fees*" beginning on page 100 of this proxy statement/prospectus.

Directors and Management of Dominion Energy After the Merger (See page 65)

Upon completion of the merger, the board of directors and executive officers of Dominion Energy are expected to remain unchanged. Pursuant to the terms of the merger agreement, as soon as practical after completion of the merger, the Dominion Energy board intends to appoint a mutually agreeable current member of the SCANA board or SCANA's executive management to serve on the Dominion Energy board. For information on Dominion Energy's current directors and executive officers, please see Dominion Energy's proxy statement dated March 20, 2017. See the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/prospectus.

Regulatory Approvals Required for the Merger (See page 67)

Under the terms of the merger agreement, to complete the merger, Dominion Energy and SCANA must obtain approvals or consents from, or make filings with, public utility, antitrust and other regulatory authorities.

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The U. S. federal and state approvals, consents and filings required under the terms of the merger agreement to complete the merger include the following:

- the expiration or early termination of certain waiting periods under the HSR Act and the related rules and regulations, which provide that certain acquisition transactions may not be completed until required information has been furnished to the Antitrust Division of the Department of Justice, which we refer to as the DOJ, and the Federal Trade Commission, which we refer to as the FTC;
- approval of the FERC under the Federal Power Act, which we refer to as the FPA;
- consent of the NRC under Section 184 of the Atomic Energy Act and the NRC's implementing regulations in 10 C.F.R. 50.80;
- approval of the GPSC under § 46-4-25 of the Official Code of Georgia, which we refer to as the O.C.G.A.;
- authorization of the NCUC under Section 62-111(a) of the North Carolina General Statutes, which we refer to as the NCGS;
- approval by the SCPSC of the SCPSC petition (other than the request for the SCPSC to make the SCPSC merger determination), unless otherwise consented to by Dominion Energy in its sole discretion, without any material changes to the terms, conditions or undertakings of the cost recovery plan or any significant change to the economic value of the cost recovery plan, in each case as reasonably determined by Dominion Energy in good faith; and
- the SCPSC merger determination.

While not a condition to the closing of the merger, the transfer of indirect control over certain licenses for private internal communications held by SCANA and certain SCANA subsidiaries will require the approval of the Federal Communications Commission, which we refer to as the FCC, and the indirect transfer of control of certain state issued radioactive material licenses will require state-level consents.

Dominion Energy and SCANA have made or intend to make various filings and submissions for the above-mentioned authorizations and approvals. Dominion Energy and SCANA filed the required HSR Act notification and report forms with the DOJ and FTC on January 19, 2018, requested early termination of the HSR Act waiting period and were granted such early termination on February 1, 2018. We cannot assure that we will obtain such consents or approvals on terms and subject to conditions that will satisfy the requirements of the merger agreement. Please see the section entitled "*The Merger—Regulatory Approvals Required for the Merger*" beginning on page 67 of this proxy statement/prospectus for additional information about these matters.

U.S. Federal Income Tax Consequences of the Merger (See page 65)

The merger is intended to be non-taxable to shareholders, provided it qualifies as a "reorganization" within the meaning of Section 368(a) of the Code. The holders of SCANA common stock are not expected to recognize any gain or loss for U.S. federal income tax purposes on the exchange of shares of SCANA common stock for shares of Dominion Energy common stock in the merger, except with respect to any cash received in lieu of fractional shares of Dominion Energy common stock.

You should read "*The Merger—U.S. Federal Income Tax Consequences of the Merger*" beginning on page 65 of this proxy statement/prospectus for a more complete discussion of the U. S. federal income tax consequences of the merger. Tax matters can be complicated and the tax consequences of the merger to you will depend on your particular tax situation. You should consult your tax advisor to determine the tax consequences of the merger to you.

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Accounting Treatment (See page 67)

Dominion Energy prepares its financial statements in accordance with generally accepted accounting principles in the United States, which we refer to as GAAP. The merger will be accounted for using the acquisition method of accounting. Dominion Energy will be treated as the acquiror for accounting purposes.

No Dissenters' Rights (See page 67)

No SCANA shareholder will be entitled to exercise any dissenters' rights, appraisal rights or other similar rights in connection with the merger and the other transactions contemplated by the merger agreement.

The Special Meeting (See page 29)

The special meeting will be held at [a.m./p.m.] Eastern Daylight Time on , 2018 at . At the special meeting, SCANA shareholders will be asked to consider and vote on:

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- the merger proposal;

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- the merger-related compensation proposal; and

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- the adjournment proposal, if necessary or appropriate in the view of the SCANA board.

You may vote at the special meeting if you owned common stock of SCANA at the close of business on the record date, , 2018. As of the record date there were shares of SCANA common stock outstanding and entitled to vote.

You may cast one (1) vote for each share of SCANA common stock that you owned on the record date.

Required Vote (See page 30)

Approval of the merger proposal requires the affirmative vote of the holders of at least two-thirds of the outstanding shares of SCANA common stock. Your failure to vote, or failure to instruct your broker, bank or other nominee to vote, or your abstention from voting, will have the same effect as a vote against the merger proposal.

The merger-related compensation proposal will be approved if more votes are cast in favor of the proposal than against the proposal. Because the votes for the merger-related compensation proposal are non-binding, if the merger agreement is approved by the SCANA shareholders and the merger is completed, the compensation that is the subject of the merger-related compensation proposal, which includes amounts SCANA is contractually obligated to pay, would still be paid regardless of the outcome of the non-binding advisory vote. Abstentions and broker non-votes will not be counted as a vote "for" or "against" the merger-related compensation proposal.

The adjournment proposal will be approved if more votes are cast in favor of the proposal than against the proposal. Abstentions and broker non-votes will not be counted as a vote "for" or "against" the adjournment proposal.

If you sign and return your proxy card without indicating how to vote on any particular proposal, SCANA common stock represented by your proxy will be voted in favor of that proposal.

As of the record date for the special meeting, the directors and executive officers of SCANA as a group owned and were entitled to vote shares of the common stock of SCANA, or approximately % of the outstanding shares of SCANA common stock on that date. SCANA currently expects that its directors and executive officers will vote their shares in favor of approval of the merger agreement, but none of SCANA's directors or executive officers have entered into any agreement obligating them to do so.

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Risk Factors (See page 17)

Before voting at the special meeting, you should carefully consider all of the information contained in or incorporated by reference into this proxy statement/prospectus, as well as the specific factors under the section entitled "*Risk Factors*" beginning on page 17 of this proxy statement/prospectus.

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SELECTED HISTORICAL FINANCIAL DATA OF DOMINION ENERGY

The selected historical consolidated financial data of Dominion Energy for each of the years ended 2016, 2015 and 2014 and at December 31, 2016 and 2015 have been derived from Dominion Energy's audited consolidated financial statements and related notes contained in its Annual Report on Form 10-K for the year ended December 31, 2016, which are incorporated by reference into this proxy statement/prospectus, and will accompany this proxy statement/prospectus mailed to SCANA shareholders in accordance with South Carolina law. The selected historical consolidated financial data for the years ended 2013 and 2012 and at December 31, 2014, 2013 and 2012 have been derived from Dominion Energy's audited consolidated financial statements, which have not been incorporated by reference into this proxy statement/prospectus. The selected historical consolidated financial data at September 30, 2017 and for the nine months ended September 30, 2017 and 2016 have been derived from Dominion Energy's unaudited consolidated financial statements and related notes contained in its Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017, which are incorporated by reference into this proxy statement/prospectus. The selected historical consolidated financial data at September 30, 2016 has been derived from Dominion Energy's unaudited consolidated financial statements, which have not been incorporated by reference into this proxy statement/prospectus. The information set forth below is only a summary and is not necessarily indicative of the results of future operations of Dominion Energy or the combined company, and you should read the following information together with Dominion Energy's audited consolidated financial statements, the related notes and the section titled "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in Dominion Energy's Annual Report on Form 10-K for the year ended December 31, 2016, and Dominion Energy's unaudited consolidated financial statements, the related notes and the section titled "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in Dominion Energy's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017, which are incorporated by reference. For more information, see the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/ prospectus.

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	Nine Months Ended September 30,		Year Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
(millions, except per share amounts)							
Dominion Energy							
Operating revenue	$ 9,376	$ 8,651	$11,737	$11,683	$12,436	$13,120	$12,835
Income from continuing operations, net of tax	1,687	1,666	2,123	1,899	1,310	1,789	1,427
Loss from discontinued operations, net of tax	—	—	—	—	—	(92)	(1,125)
Net income attributable to Dominion Energy	1,687	1,666	2,123	1,899	1,310	1,697	302
Income from continuing operations before loss from discontinued operations per common share-basic	2.66	2.72	3.44	3.21	2.25	3.09	2.49
Net income attributable to Dominion Energy per common share-basic	2.66	2.72	3.44	3.21	2.25	2.93	0.53
Income from continuing operations before loss from discontinued operations per common share-diluted	2.66	2.71	3.44	3.20	2.24	3.09	2.49
Net income attributable to Dominion Energy per common share-diluted	2.66	2.71	3.44	3.20	2.24	2.93	0.53
Dividends declared per common share	2.265	2.10	2.80	2.59	2.40	2.25	2.11
Total assets	75,391	69,599	71,610	58,648	54,186	49,963	46,711
Long-term debt	30,886	28,707	30,231	23,468	21,665	19,199	16,736

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SELECTED HISTORICAL FINANCIAL DATA OF SCANA

The selected historical consolidated financial data of SCANA for the years ended 2016, 2015 and 2014 and at December 31, 2016 and 2015 have been derived from SCANA's audited consolidated financial statements and related notes contained in its Annual Report on Form 10-K for the year ended December 31, 2016, which are incorporated by reference into this proxy statement/prospectus, and will accompany this proxy statement/prospectus mailed to SCANA shareholders in accordance with South Carolina law. The selected historical consolidated financial data for the years ended 2013 and 2012 and at December 31, 2014, 2013 and 2012 have been derived from SCANA's audited consolidated financial statements, which have not been incorporated by reference into this proxy statement/prospectus. The selected historical consolidated financial data at September 30, 2017 and for the nine months ended September 30, 2017 and 2016 have been derived from SCANA's unaudited consolidated financial statements and related notes contained in its Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017, which are incorporated by reference into this proxy statement/prospectus. The selected historical consolidated financial data at September 30, 2016 has been derived from SCANA's unaudited consolidated financial statements, which have not been incorporated by reference into this proxy statement/prospectus. The information set forth below is only a summary and is not necessarily indicative of the results of future operations of SCANA or the combined company, and you should read the following information together with SCANA's audited consolidated financial statements, the related notes and the section titled "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in SCANA's Annual Report on Form 10-K for the year ended December 31, 2016, and SCANA's unaudited consolidated financial statements, the related notes and the section titled "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in SCANA's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017, which are incorporated by reference into this proxy statement/prospectus. See the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/prospectus.

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	Nine Months Ended September 30,		Year Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
(millions, except per share amounts)							
SCANA							
Operating revenues	$ 3,249	$ 3,171	$ 4,227	$ 4,380	$ 4,951	$ 4,495	$ 4,176
Operating income	685	900	1,153	1,308	1,007	910	859
Net income	326	471	595	746	538	471	420
Earnings per share of common stock—basic	2.28	3.29	4.16	5.22	3.79	3.40	3.20
Earnings per share of common stock—diluted	2.28	3.29	4.16	5.22	3.79	3.39	3.15
Dividends declared per common share	1.8375	1.7250	2.30	2.18	2.10	2.03	1.98
Total assets	20,019	18,446	18,707	17,146	16,818	15,127	14,568
Short-term and long-term debt	7,654	7,367	7,431	6,529	6,581	5,788	5,707

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SELECTED UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL INFORMATION

The following selected unaudited pro forma consolidated financial information is derived from the unaudited pro forma consolidated statements of income data of Dominion Energy for the nine months ended September 30, 2017 and the year ended December 31, 2016, which have been prepared to give effect to the merger as if the merger was completed on January 1, 2016, and the unaudited pro forma condensed consolidated balance sheet of Dominion Energy at September 30, 2017, which has been prepared to give effect to the merger as if the merger was completed on September 30, 2017.

The following selected unaudited pro forma consolidated financial information is for illustrative and informational purposes only and is not necessarily indicative of the results that might have occurred had the merger taken place on January 1, 2016, for statements of income purposes, and September 30, 2017 for balance sheet purposes, and is not intended to be a projection of future results. Future results may vary significantly from the results reflected because of various factors, including those discussed in the section entitled "*Risk Factors*" beginning on page 17 of this proxy statement/prospectus. The following selected unaudited pro forma consolidated financial information should be read in conjunction with the section titled "*Unaudited Pro Forma Consolidated Financial Statements*" and related notes included in this proxy statement/prospectus beginning on page 112 of this proxy statement/prospectus.

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(millions, except per share amounts)	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
Pro Forma Consolidated Dominion Energy		
Operating revenue	$ 12,590	$ 15,970
Income from continuing operations, net of tax	2,014	2,741
Net income attributable to Dominion Energy	2,014	2,741
Income from continuing operations per common share-basic	2.76	3.85
Net income attributable to Dominion Energy per common share-basic	2.76	3.85
Income from continuing operations per common share-diluted	2.76	3.85
Net income attributable to Dominion Energy per common share-diluted	2.76	3.85
Total assets	95,657	
Long-term debt	37,393	

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EQUIVALENT AND COMPARATIVE PER SHARE INFORMATION

The following table summarizes unaudited per share data for (i) Dominion Energy and SCANA on a historical basis, (ii) Dominion Energy on a pro forma combined basis giving effect to the merger and (iii) SCANA on a pro forma equivalent basis calculated by multiplying the Dominion Energy pro forma combined data by the exchange ratio of 0.6690. It has been assumed for purposes of the pro forma combined financial information provided below that the merger was completed on January 1, 2016, for earnings per share purposes, and on September 30, 2017, for shareholders' equity per share purposes. The following information should be read in conjunction with the section entitled "*Unaudited Pro Forma Consolidated Financial Statements*" and related notes included in this document beginning on page 112 of this proxy statement/prospectus.

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	Dominion Energy		SCANA	
	Historical	Pro Forma Combined	Historical	Pro Forma Equivalent(a)
Nine Months Ended September 30, 2017				
Basic earnings per share of common stock	$ 2.66	$ 2.76	$ 2.28	$ 1.85
Diluted earnings per share of common stock	2.66	2.76	2.28	1.85
Cash dividends declared per share	2.265	2.265	1.8375	1.515
Book value per share(b)	25.28	29.98	40.47	20.06
Year Ended December 31, 2016				
Basic earnings per share of common stock	3.44	3.85	4.16	2.58
Diluted earnings per share of common stock	3.44	3.85	4.16	2.58
Cash dividends declared per share	2.80	2.80	2.30	1.87

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(a) The unaudited SCANA pro forma equivalents are calculated by multiplying the unaudited Dominion Energy pro forma combined per share amounts by the exchange ratio of 0.6690.

(b) Historical book value per share for Dominion Energy and SCANA represents the total shareholders' equity at September 30, 2017 divided by the number of shares of Dominion Energy or SCANA shares outstanding. The unaudited Dominion Energy pro forma combined book value per share represents the total pro forma shareholders' equity at September 30, 2017 divided by the pro forma combined number of shares of Dominion Energy common stock that would have been outstanding at September 30, 2017 had the merger been completed at that date.

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COMPARATIVE STOCK PRICES AND DIVIDENDS

Dominion Energy common stock is traded on the NYSE under the symbol "D" and SCANA common stock is traded on the NYSE under the symbol "SCG." The following table presents the closing prices for shares of Dominion Energy common stock and SCANA common stock on January 2, 2018, the last trading day before the public announcement of the execution of the merger agreement, and February 13, 2018 the latest practicable trading day before the date of this proxy statement/prospectus. The table also shows the equivalent per share value of the merger consideration for each share of SCANA common stock, which per share values are calculated as the product of (i) the Dominion Energy per share values and (ii) 0.6690, the exchange ratio.

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Date	Dominion Energy Common Stock Closing Price	SCANA Common Stock Closing Price	Equivalent Per Share Information
January 2, 2018	$ 80.28	$ 38.87	$ 53.71
February 13, 2018	$ 75.07	$ 36.02	$ 50.22

The above table shows only historical comparisons. These comparisons may not provide meaningful information to SCANA shareholders in determining whether to approve the merger agreement. SCANA shareholders are urged to obtain current market quotations for Dominion Energy common stock and SCANA common stock and to review carefully the other information contained in this proxy statement/prospectus or incorporated by reference into this proxy statement/prospectus in considering whether to approve the merger agreement. See the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/prospectus for instructions on how to obtain the information that has been incorporated by reference. Historical performance is not necessarily indicative of any performance to be expected in the future. See the sections entitled "*Risk Factors*" and "*Cautionary Statement Regarding Forward-Looking Statements*" beginning on pages 17 and 25, respectively, of this proxy statement/prospectus.

Market Price and Dividend Data

The following table sets forth the high and low sales prices of Dominion Energy common stock as reported on the NYSE and the quarterly cash dividends declared per share in respect of Dominion Energy common stock for the calendar quarters indicated.

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	Dominion Energy		
	Price Range		
	High	Low	Dividends
2016			
First Quarter	$75.18	$66.25	$ 0.700
Second Quarter	77.93	68.71	0.700
Third Quarter	78.97	72.49	0.700
Fourth Quarter	77.32	69.51	0.700
2017			
First Quarter	$79.36	$70.87	$ 0.755
Second Quarter	81.65	76.17	0.755
Third Quarter	80.67	75.40	0.755
Fourth Quarter	85.30	75.75	0.770
2018			
First Quarter through February 13, 2018	$81.67	$72.80	

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Dividends on Dominion Energy common stock are paid as declared by the Dominion Energy board. On January 26, 2018, the Dominion Energy board declared a quarterly dividend of $0.835 per share payable on March 20, 2018 to shareholders of record on March 2, 2018. Dividends are typically paid on the 20th of March, June, September and December of each year.

As of January 31, 2018, Dominion Energy had approximately 651.5 million shares of its common stock outstanding, and there were approximately 123,000 holders of record of Dominion Energy common stock.

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RISK FACTORS

In addition to the other information included or incorporated by reference into this proxy statement/prospectus, including the matters addressed in the section entitled "Cautionary Statement Regarding Forward-Looking Statements" beginning on page 25 of this proxy statement/prospectus, you should carefully consider the following risks before deciding how to vote on the proposals set forth in this document. In addition, you should read and consider the risks associated with each of the businesses of Dominion Energy and SCANA because these risks may also affect the combined company. A description of the material risks can be found in the Annual Reports on Form 10-K for the fiscal year ended December 31, 2016 for each of Dominion Energy and SCANA, as updated by any subsequent Quarterly Reports on Form 10-Q, all of which are filed with the SEC and incorporated by reference into this proxy statement/prospectus. You should also read and consider the other information in this proxy statement/prospectus and the other documents incorporated by reference into this proxy statement/prospectus. See the section entitled "Where You Can Find More Information" beginning on page 136 of this proxy statement/prospectus.

Risk Factors Relating to the Merger

Because the market price of Dominion Energy common stock will fluctuate, SCANA shareholders cannot be certain of the market value of the merger consideration they will receive.

Upon completion of the merger, each outstanding share of SCANA common stock (other than cancelled shares) will be converted into the right to receive 0.6690 of a share of Dominion Energy common stock. The market value of Dominion Energy common stock received in the merger may vary significantly from the closing price of Dominion Energy common stock on the date Dominion Energy and SCANA announced the merger, on the date that this proxy statement/prospectus is mailed to SCANA shareholders, or on the date of the special meeting. Any change in the market price of Dominion Energy common stock prior to the completion of the merger will affect the market value of the merger consideration that SCANA shareholders will receive upon completion of the merger, which may not occur until a significant period of time has passed since the date of the special meeting, and there will be no adjustment to the merger consideration for changes in the market price of either shares of Dominion Energy common stock or shares of SCANA common stock. Neither Dominion Energy nor SCANA is permitted to terminate the merger agreement because of changes in the market price of SCANA common stock or Dominion Energy common stock.

Stock price changes may result from a variety of factors that are beyond the control of Dominion Energy and SCANA, including, but not limited to, general market and economic conditions, changes in the companies' respective businesses, operations and prospects, regulatory considerations, litigation and speculation regarding the likelihood that the merger will be completed and the timing of completion. Therefore, at the time of the special meeting you will not know the precise market value of the consideration you will receive upon completion of the merger. You should obtain current market quotations for shares of Dominion Energy common stock and for shares of SCANA common stock.

The completion of the merger is subject to the receipt of consents, approvals and/or findings from governmental entities, which may impose conditions that could have an adverse effect on Dominion Energy or SCANA or could cause either Dominion Energy or SCANA to abandon the merger. The completion of the merger is also subject to there not having been substantive changes in certain South Carolina laws that have or would reasonably be expected to have an adverse effect on SCANA or its subsidiaries or orders of governmental entities or changes in law that impose any condition that would reasonably be expected to result in specified changes to the SCPSC petition.

Dominion Energy and SCANA are not required to complete the merger until after the applicable waiting period under the HSR Act expires or terminates and the requisite authorizations, approvals, consents and/or permits are received from the FERC, NRC, SCPSC, NCUC and GPSC. Any of the relevant governmental entities

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may oppose the merger, fail to approve the merger, fail to make required findings in favor of the merger, or impose certain requirements or obligations as conditions for their consent, approval or findings or in connection with their review. Regulatory approvals of the merger or findings with respect to the merger may not be obtained on a timely basis or at all, and such approvals or findings may include conditions that could have an adverse effect on Dominion Energy and/or SCANA, and/or result in the abandonment of the merger. The terms of any conditions imposed in order to obtain the requisite regulatory approvals or findings may not be known by the date of the special meeting. Neither Dominion Energy nor SCANA can provide any assurance that they will obtain the necessary approvals or findings or that any required conditions will not have an adverse effect on Dominion Energy following the merger. If SCANA shareholders vote in favor of the merger proposal at the special meeting, Dominion Energy or SCANA may make decisions after the special meeting to waive a condition or approve certain actions required to obtain regulatory approvals or findings without seeking further approval of the SCANA shareholders.

Subject to the terms and conditions set forth in the merger agreement, the merger agreement may require Dominion Energy to accept conditions from regulators that could adversely impact Dominion Energy after the merger without either of Dominion Energy or SCANA having the right to refuse to close the merger on the basis of those regulatory conditions, except that Dominion Energy is generally not required, and SCANA is generally not permitted without Dominion Energy's prior approval, to take any action or accept any condition that results in a burdensome condition, as described in "*The Merger Agreement—Reasonable Best Efforts to Obtain Regulatory Approvals*" on page 92 of this proxy statement/prospectus.

In addition, the merger agreement provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if, since the date of the merger agreement, any governmental entity shall have enacted any order, or there shall have been any change in law (including the BLRA and the other laws governing South Carolina public utilities), which imposes any material change to the terms, conditions or undertakings set forth in the SCPSC petition, or any significant changes to the economic value of the proposed terms set forth in the SCPSC petition, in each case as determined by Dominion Energy in good faith.

The merger agreement further provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if there shall have occurred any substantive change in the BLRA or other laws governing South Carolina public utilities which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries. There is currently pending before the South Carolina Senate a bill that would make substantive changes to the BLRA. This bill (H.4375) has passed the South Carolina House of Representatives. If this bill becomes law, Dominion Energy would not be obligated to complete the merger if it is determined that the bill has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries.

Certain lawsuits and regulatory actions have been filed against SCANA and SCE&G in connection with the abandonment of the NND project. If the relief requested in these matters (including a request for declaratory judgment that the BLRA is unconstitutional) is granted, Dominion Energy might not be obligated to complete the merger.

Dominion Energy and SCANA can provide no assurance that these risks will not materialize and either adversely impact Dominion Energy after the completion of the merger or, if such conditions rise to the thresholds discussed above, some of which, as described above, are in the subjective determination of Dominion Energy acting in good faith, or if the required authorizations, approvals, consents and/or permits are not obtained or received, result in the abandonment of the merger. See the sections entitled "*The Merger—Regulatory Approvals Required for the Merger*" beginning on page 67 of this proxy statement/prospectus and "*The Merger Agreement—Conditions to Completion of the Merger*" beginning on page 88 of this proxy statement/prospectus.

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Failure to complete the merger could negatively impact the stock price and the future business and financial results of SCANA.

If the merger is not completed, the ongoing business of SCANA may be adversely affected and SCANA could be subject to several risks, including the following:

- the price of SCANA common stock may decline to the extent that the current market price reflects an expectation by the market that the merger will be completed;
- obligations to pay certain costs relating to the merger, such as legal, accounting, financial advisory, filing, printing and mailing fees;
- the disruption of SCANA's ongoing business or inconsistencies in its services, standards, controls, procedures and policies due to management's focus on the merger, any of which could adversely affect the ability of SCANA to maintain relationships with customers, regulators, vendors and employees, or could otherwise adversely affect the business and financial results of SCANA, without realizing any of the benefits of having the merger completed;
- the potential negative impact on SCANA ultimately resolving the rate and regulatory issues, including pending investigations and legal challenges, relating to the abandonment of the NND project in a manner satisfactory to SCANA on account of SCANA working with Dominion Energy to pursue the resolution of these issues as contemplated by the merger agreement rather than pursuing its regulatory and legal options for resolving these issues independently of considerations and obligations related to the merger; and
- the loss of other opportunities that could be beneficial to SCANA that could have been pursued during the pendency of the merger, without realizing any of the benefits of having the merger completed.

In addition to the above risks, SCANA may be required, under certain circumstances, to pay to Dominion Energy a termination fee of $240 million.

If the merger is not completed, SCANA cannot assure SCANA shareholders that these risks will not materialize and will not materially affect its business, financial results and stock price.

The merger agreement contains provisions that limit SCANA's ability to pursue alternatives to the merger, which could discourage a potential competing acquirer of SCANA or could result in any competing proposal being at a lower price than it might otherwise be.

The merger agreement contains provisions that, subject to certain exceptions, restrict SCANA's ability to initiate, solicit, knowingly encourage, facilitate or discuss competing third-party proposals to acquire all or a significant part of SCANA, or provide information to a third party that could reasonably be expected to lead to such a proposal. See the section entitled "*The Merger Agreement—Non-Solicitation of Alternative Proposals*" on page 95 of this proxy statement/prospectus. In addition, Dominion Energy generally has an opportunity to offer to modify the terms of the merger in response to any superior acquisition proposal that may be made before the SCANA board is permitted to withdraw or qualify its recommendation. In some circumstances on termination of the merger agreement, SCANA may be required to pay to Dominion Energy a termination fee of $240 million. See the section entitled "*The Merger Agreement—Non- Solicitation of Alternative Proposals*" beginning on page 95 of this proxy statement/prospectus, "*The Merger Agreement—Termination of the Merger Agreement*" beginning on page 99 of this proxy statement/prospectus and "*The Merger Agreement—Termination Fees*" beginning on page 100 of this proxy statement/prospectus.

These provisions, which the SCANA board regards as customary for transactions for this type, could discourage a potential competing acquirer that might have an interest in acquiring all or a significant part of SCANA from considering or proposing that acquisition, even if it were prepared to pay consideration with a higher per share cash or market value than the merger consideration, or might result in a potential competing acquirer proposing to pay a lower price than it might otherwise have proposed to pay because of the added expense of the termination fee that may become payable by SCANA in certain circumstances.

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The pendency of the merger could adversely affect the business and operations of SCANA.

In connection with the pending merger, some current or prospective customers or vendors of SCANA's utilities may delay or defer decisions regarding their existing or proposed relationships with those utilities, which could negatively impact the revenues, earnings, cash flows and expenses of SCANA, regardless of whether the merger is completed. Similarly, current and prospective employees of SCANA and its utilities may experience uncertainty about their future roles following the merger, which may materially adversely affect the ability of SCANA and its utilities to attract and retain key personnel during the pendency of the merger. In addition, due to operating covenants in the merger agreement, during the pendency of the merger, SCANA and its utilities may be unable to pursue strategic transactions, undertake significant capital projects, undertake certain significant financing or other specified transactions or pursue actions that are not in the ordinary course of business, even if such actions would prove beneficial.

Certain directors and executive officers of SCANA may have interests in the merger that may differ from, or be in addition to, the interests of SCANA shareholders.

Executive officers of SCANA negotiated the terms of the merger agreement with their counterparts at Dominion Energy, and the SCANA board approved the transactions contemplated by the merger agreement. In considering these facts and the other information contained in this proxy statement/prospectus, you should be aware that SCANA's executive officers and directors may have interests in the merger that may be different from, or in addition to, the interests of SCANA shareholders. These interests include the accelerated vesting of equity awards, arrangements that provide for severance benefits if the employment of a SCANA executive officer is terminated under specified circumstances following the completion of the merger and rights to indemnification and director's and officer's liability insurance that will survive the completion of the merger. For a detailed discussion of the interests that SCANA's directors and executive officers may have in the merger, please see the section entitled "*The Merger—Interests of SCANA's Directors and Executive Officers in the Merger*" beginning on page 72 of this proxy statement/prospectus.

SCANA shareholders will have a reduced ownership and voting interest in the combined company.

SCANA shareholders currently have the right to vote in the election of directors of SCANA and on certain other matters affecting SCANA. Following the merger, each SCANA shareholder will become a shareholder of Dominion Energy with a percentage ownership of the combined company that is much smaller than the shareholder's percentage ownership of SCANA. It is expected that the former SCANA shareholders as a group will own approximately 13% of the outstanding shares of Dominion Energy common stock immediately after the completion of the merger. Because of this, the SCANA shareholders, as a group, will have substantially less influence on the management and policies of Dominion Energy than they now have, as a group, with respect to the management and policies of SCANA.

Dominion Energy expects to incur substantial expenses related to the merger.

Dominion Energy expects to incur relatively significant expenses in connection with completing the merger. While Dominion Energy has assumed that a certain level of transaction and integration expenses would be incurred, there are a number of factors beyond its control that could affect the total amount or the timing of its integration expenses. Many of the expenses that will be incurred, by their nature, are difficult to estimate accurately at the present time.

Following the merger, Dominion Energy may be unable to successfully integrate SCANA's businesses.

Dominion Energy and SCANA currently operate as independent public companies. After the merger, Dominion Energy will be required to devote significant management attention and resources to integrating
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SCANA's business. Potential difficulties Dominion Energy may encounter in the integration process include the following:

- the complexities associated with integrating SCANA and its utility businesses, while at the same time continuing to provide consistent, high quality services;
- the complexities of integrating a company with different core services, markets and customers;
- the inability to attract and retain key employees;
- potential unknown liabilities and unforeseen increased expenses, delays or regulatory conditions associated with the merger;
- difficulties in managing political and regulatory conditions related to SCANA's utility businesses after the merger;
- the cost recovery plan includes a moratorium on filing requests for adjustments in SCE&G's base electric rates until 2021 if the merger is approved by the SCPSC, which would limit Dominion Energy's ability to recover increases in non-fuel related costs of electric operations for SCE&G's customers; and
- performance shortfalls as a result of the diversion of Dominion Energy management's attention caused by completing the merger and integrating SCANA's utility businesses.

For these reasons, you should be aware that it is possible that the integration process following the merger could result in the distraction of Dominion Energy's management, the disruption of Dominion Energy's ongoing business or inconsistencies in its services, standards, controls, procedures and policies, any of which could adversely affect the ability of Dominion Energy to maintain or establish relationships with current and prospective customers, vendors and employees or could otherwise adversely affect the business and financial results of Dominion Energy.

Dominion Energy and SCANA may be materially adversely affected by negative publicity related to the merger and in connection with other related matters, including the abandonment of the NND project.

From time to time, political and public sentiment in connection with the merger and in connection with other matters, including the abandonment of the NND project, may result in a significant amount of adverse press coverage and other adverse public statements affecting Dominion Energy and SCANA. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceedings, as well as responding to and addressing adverse press coverage and other adverse public statements, can divert the time and effort of senior management from the management of Dominion Energy's and SCANA's respective businesses.

Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of Dominion Energy and SCANA, on the morale and performance of their employees and on their relationships with their respective regulators, customers and commercial counterparties. It may also have a negative impact on their ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on Dominion Energy's and SCANA's respective business, financial condition, results of operations and prospects.

The market price of Dominion Energy common stock after the merger may be affected by factors different from those affecting the market price of SCANA common stock currently.

Upon completion of the merger, holders of SCANA common stock will become holders of Dominion Energy common stock. Dominion Energy's business differs in important respects from that of SCANA, and,

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accordingly, the results of operations of the combined company and the market price of Dominion Energy common stock after the completion of the merger may be affected by factors different from those currently affecting the independent results of operations of each of Dominion Energy and SCANA. For a discussion of the businesses of Dominion Energy and SCANA and of some important factors to consider in connection with those businesses, see the documents incorporated by reference in this proxy statement/prospectus and referred to under the section entitled "*Where You Can Find More Information*" on page 136 of this proxy statement/prospectus.

The market value of Dominion Energy common stock could decline if large amounts of its common stock are sold following the merger.

Following the merger, shareholders of Dominion Energy and former SCANA shareholders will own interests in a combined company operating an expanded business with more assets and a different mix of liabilities. Current shareholders of Dominion Energy and SCANA may not wish to continue to invest in the combined company, or may wish to reduce their investment in the combined company, in order to comply with institutional investing guidelines, to increase diversification or to track any rebalancing of stock indices in which Dominion Energy common stock or SCANA common stock is or was included. If, following the merger, large amounts of Dominion Energy common stock are sold, the price of its common stock could decline.

The merger may not be accretive to operating earnings and may cause dilution to Dominion Energy's earnings per share, which may negatively affect the market price of Dominion Energy common stock.

Dominion Energy currently anticipates that the merger will be immediately accretive to Dominion Energy's forecasted operating earnings per share on a standalone basis. This expectation is based on preliminary estimates, which may materially change. Dominion Energy may encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates or its ability to realize operational efficiencies. Any of these factors could cause a decrease in Dominion Energy's operating earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Dominion Energy's common stock. Dominion Energy expects that the initial effect of the merger on its GAAP earnings will be a decrease in such earnings due to anticipated charges for refunds to SCE&G electric customers, write-offs of regulatory assets and transaction costs.

Pending litigation against SCANA and Dominion Energy could result in an injunction preventing the completion of the merger or may adversely affect the combined company's business, financial condition or results of operations following the merger.

Following the announcement of the merger, three (3) lawsuits have been filed asserting claims relating to the merger. First, an existing derivative lawsuit was amended to assert direct claims on behalf of a putative class of SCANA shareholders in the Court of Common Pleas of the County of Richland, South Carolina against the members of the SCANA board, Dominion Energy and Merger Sub, alleging breaches of various fiduciary duties by the members of the SCANA board in connection with the merger and alleging that Dominion Energy and Merger Sub aided and abetted such alleged breaches. Second, two (2) putative class actions on behalf of SCANA shareholders have been filed in the Court of Common Pleas of the Counties of Lexington and Richland, South Carolina, respectively, against SCANA, the members of the SCANA board, Dominion Energy and Merger Sub, alleging breaches of various fiduciary duties by the members of the SCANA board in connection with the merger and alleging that SCANA, Dominion Energy and Merger Sub aided and abetted such alleged breaches. Among other remedies, the plaintiffs in each case seek to enjoin the merger and rescind the merger agreement. In addition, the second and third lawsuits seek in the alternative, should the merger be completed, an award of unspecified monetary damages.

While the defendants believe that dismissal is warranted, the outcome of any such litigation is inherently uncertain. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger closes may adversely affect the combined company's business, financial condition or results of operation. See the
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section entitled "*The Merger—Litigation Relating to the Merger*" beginning on page 71 of this proxy statement/prospectus for more detail.

The unaudited pro forma combined financial information and prospective financial information included in this proxy statement/prospectus are presented for illustrative purposes only and do not represent the actual financial position or results of operations of the combined company following the merger.

The unaudited pro forma combined financial information and prospective financial information contained in this proxy statement/prospectus are presented for illustrative purposes only, contain a variety of adjustments, assumptions and preliminary estimates and do not represent the actual financial position or results of operations of Dominion Energy and SCANA prior to the merger or that of the combined company following the merger for several reasons. See the sections entitled *"Equivalent and Comparative Per Share Information*" beginning on page 14 of this proxy statement/prospectus and "*Unaudited Pro Forma Consolidated Financial Statements*" beginning on page 112 of this proxy statement/prospectus.

The actual financial positions and results of operations of Dominion Energy and SCANA prior to the merger and those of the combined company following the merger may not be consistent with, or evident from, the unaudited pro forma combined financial information and prospective financial information included in this proxy statement/prospectus. In addition, the assumptions used in preparing the unaudited pro forma combined financial information and prospective financial information included in this proxy statement/prospectus may not prove to be accurate and may be affected by other factors. Any significant changes in the share price of Dominion Energy may cause a significant change in the purchase price and the pro forma financial information.

Dominion Energy has goodwill and other intangible assets on its balance sheet, and these amounts will increase as a result of the merger. If its goodwill or other intangible assets become impaired in the future, Dominion Energy may be required to record a significant, non-cash charge to earnings and reduce its shareholders' equity.

Upon the completion of the merger, Dominion Energy will record as goodwill the excess of the purchase price paid by Dominion Energy over the fair value of SCANA's assets and liabilities as determined for financial accounting purposes. Under GAAP, intangible assets are reviewed for impairment on an annual basis or more frequently whenever events or circumstances indicate that its carrying value may not be recoverable. If Dominion Energy's intangible assets, including goodwill as a result of the merger, are determined to be impaired in the future, Dominion Energy may be required to record a significant, non-cash charge to earnings during the period in which the impairment is determined.

The shares of Dominion Energy common stock to be received by SCANA shareholders as a result of the merger will have different rights from the shares of SCANA common stock.

Upon completion of the merger, SCANA shareholders will become Dominion Energy shareholders and their rights as shareholders will be governed by the Virginia Stock Corporation Act, which we refer to as the VSCA, and Dominion Energy's amended and restated articles of incorporation, which we refer to as the Dominion Energy charter, and amended and restated bylaws, which we refer to as the Dominion Energy bylaws. The rights associated with SCANA common stock are different from the rights associated with Dominion Energy common stock. See the section entitled "*Comparison of Shareholder Rights*" beginning on page 122 of this proxy statement/prospectus for a summary of the material differences between the rights of holders of Dominion Energy common stock and the rights of holders of SCANA common stock.

The merger may fail to qualify as a tax-free reorganization for federal tax purposes, resulting in the SCANA shareholders' recognition of taxable gain or loss in respect of their SCANA common stock.

Dominion Energy and SCANA intend the merger to qualify as a reorganization within the meaning of Section 368(a) of the Code. At the time of effectiveness of the registration statement relating to this proxy

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statement/prospectus, Dominion Energy and SCANA have obtained written tax opinions from Morgan, Lewis & Bockius, LLP, special tax counsel to Dominion Energy, and from Mayer Brown LLP, legal counsel to SCANA, respectively, that the merger will qualify as a reorganization within the meaning of Section 368(a) of the Code. In addition, Dominion Energy and SCANA expect to receive written tax opinions from Morgan, Lewis & Bockius LLP and Mayer Brown, LLP, respectively, dated the closing date of the merger, to the effect that the merger will qualify as a "reorganization" within the meaning of Section 368(a) of the Code. Such tax opinions were and will be based on customary assumptions and representations made by Dominion Energy and SCANA, as well as certain covenants and undertakings by Dominion Energy and SCANA. Such opinions will not bind the Internal Revenue Service, which we refer to as the IRS, or any court, or prevent the IRS from adopting a contrary position. In addition, neither Dominion Energy nor SCANA intends to request a ruling from the IRS regarding the U. S. federal income tax consequences of the merger. Accordingly, even with the tax opinions that conclude that the merger will qualify as a reorganization within the meaning of Section 368(a) of the Code, no assurance can be given that the IRS, will not challenge the conclusions reflected in the opinion or that a court would not sustain such a challenge. If the merger fails to qualify as a reorganization, a SCANA shareholder generally would recognize gain or loss for U. S. federal income tax purposes on each share of SCANA common stock surrendered in an amount equal to the difference between such shareholder's adjusted tax basis in that share and the fair market value of the merger consideration received in exchange for that share upon completion of the merger. SCANA shareholders should read the section entitled "*The Merger—U. S. Federal Income Tax Consequences of the Merger*" on page 65 of this proxy statement/prospectus and consult their own tax advisors regarding the U. S. federal income tax consequences of the merger to SCANA shareholders in their particular circumstances.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This proxy statement/prospectus and the information incorporated by reference in this proxy statement/prospectus include forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These forward-looking statements are subject to risks and uncertainties, and actual results might differ materially from those discussed in, or implied by, the forward-looking statements. Forward-looking statements are based on the current beliefs and assumptions of the management of Dominion Energy and SCANA and can often be identified by terms and phrases that include “anticipate,” “believe,” “intend,” “estimate,” “expect,” “continue,” “should,” “would,” “could,” “may,” “plan,” “project,” “predict,” “will,” “potential,” “forecast,” “target,” “guidance,” “outlook,” or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements included or incorporated by reference in this proxy statement/prospectus might not occur or might occur to a different extent or at a different time than described. Actual results may differ materially from the current expectations of Dominion Energy and SCANA depending on a number of factors affecting their businesses and risks associated with the successful execution of the merger and the integration and performance of their businesses following the merger. In evaluating these forward-looking statements, you should carefully consider the risks described herein and in other reports that Dominion Energy and SCANA file with the SEC. See the sections entitled “*Risk Factors*” beginning on page 17 of this proxy statement/prospectus and “*Where You Can Find More Information*” beginning on page 136 of this proxy statement/prospectus. Factors which could have a material adverse effect on operations and future prospects or which could cause events or circumstances to differ from the forward-looking statements include, but are not limited to:

- the occurrence of any event, change or other circumstances that could give rise to the termination of the merger agreement;
- the risk that SCANA shareholders may not approve the merger proposal;
- the risk that the necessary regulatory approvals may not be obtained or may be obtained subject to conditions that are not anticipated, may be burdensome and/or fail to satisfy the requirements of the merger agreement;
- the risk that any repeal of or amendment to the BLRA may be enacted that does not satisfy the requirements of the merger agreement;
- the risk that a condition to closing of the merger may not be satisfied;
- the timing of the completion the merger;
- the possibility that the anticipated benefits from the merger cannot be fully realized or may take longer to realize than expected;
- risks related to disruption of management time from ongoing business operations due to the merger;
- the possibility that costs, difficulties or disruptions related to the integration of SCANA’s operations into Dominion Energy will be greater than expected;
- the timing and extent of changes in interest rates, commodity prices and demand and market prices for electricity;
- changes in the future cash requirements of Dominion Energy following the merger, whether caused by unanticipated increases in capital expenditures or otherwise;
- risks related to any legal proceedings that have been or may be instituted against Dominion Energy, SCANA and/or others relating to the merger; and

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- the effect of the announcement of the merger on Dominion Energy's and SCANA's operating results and businesses generally.

Except as otherwise required by law, neither Dominion Energy nor SCANA is under any obligation, and each expressly disclaims any obligation, to update, alter, or otherwise revise any forward-looking statements, whether written or oral, that may be made from time to time, whether as a result of new information, future events, or otherwise. Persons reading this proxy statement/prospectus are cautioned not to place undue reliance on these forward-looking statements which speak only as of the date hereof.

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THE COMPANIES

Dominion Energy

120 Tredegar Street
Richmond, Virginia 23219
(804) 819-2000

Headquartered in Richmond, Virginia and incorporated in Virginia in 1983, Dominion Energy is one of the nation's largest producers and transporters of energy, with a portfolio of approximately 26,000 megawatts of electric generation, 66,100 miles of natural gas transmission, gathering, storage and distribution pipelines and 64,500 miles of electric transmission and distribution lines. Dominion Energy's strategy is to be a leading provider of electricity, natural gas and related services to customers primarily in the eastern and Rocky Mountain regions of the U.S. Dominion Energy operates one of the largest natural gas storage systems in the U.S. with 1 trillion cubic feet of capacity, and serves nearly 6 million utility and retail energy customers.

Dominion Energy is focused on expanding its investment in regulated and long-term contracted electric generation, transmission and distribution and regulated natural gas transmission and distribution infrastructure. Dominion Energy's nonregulated operations include merchant generation, energy marketing and price risk management activities and natural gas retail energy marketing operations. Dominion Energy's operations are conducted through various subsidiaries, including (i) Virginia Electric and Power Company, a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina, which we refer to as Virginia Power, (ii) Dominion Energy Gas Holdings, LLC, a holding company for the majority of Dominion Energy's regulated natural gas businesses, which conducts business activities through a regulated interstate natural gas transmission pipeline and underground storage system, a local, regulated natural gas transportation and distribution network and natural gas gathering and processing facilities, which we refer to Dominion Energy Gas, and (iii) Dominion Energy Questar Corporation, a holding company for Dominion Energy's primarily regulated natural gas businesses, including retail natural gas distribution in Utah, Wyoming and Idaho and related natural gas development and production. Dominion Energy also owns the general partner, 50.6% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Energy Midstream Partners, LP, which was formed by Dominion Energy to own and grow a portfolio of natural gas terminaling, processing, storage, transportation and related assets.

Dominion Energy's common stock is listed on the NYSE under the symbol "D."

Additional information about Dominion Energy is included in the documents incorporated by reference into this proxy statement/prospectus. See the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/prospectus.

SCANA

100 SCANA Parkway
Cayce, South Carolina 29033
(803) 217-9000

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA, through its wholly owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in the central, southern and southwestern portions of South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. SCANA, through a wholly owned nonregulated subsidiary also markets natural gas to retail customers in Georgia and to wholesale customers in the southeast United States.

SCANA common stock is traded on the NYSE under the symbol "SCG."

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Additional information about SCANA and its subsidiaries is included in the documents incorporated by reference into this proxy statement/prospectus. See the section entitled "*Where You Can Find More Information*" on page 136 of this proxy statement/prospectus.

Merger Sub

120 Tredegar Street
Richmond, Virginia 23219
(804) 819-2000

Merger Sub, a wholly owned subsidiary of Dominion Energy, is a South Carolina corporation formed on December 29, 2017 for the purpose of effecting the merger. To date, Merger Sub has not conducted any activities other than those incidental to its formation and the matters contemplated by the merger agreement in connection with the merger.
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THE SPECIAL MEETING

Date, Time and Place

The special meeting will be held at [a.m./p.m.], Eastern Daylight Time on , 2018 at .

Purpose of the Special Meeting

The special meeting is being held for the SCANA shareholders to consider and vote on the following proposals:

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1. the proposal to approve the merger agreement, pursuant to which Merger Sub will be merged with and into SCANA, with SCANA surviving the merger as a wholly owned subsidiary of Dominion Energy, and each outstanding share of SCANA common stock will be converted into the right to receive 0.6690 of a share of Dominion Energy common stock, with cash paid in lieu of fractional shares;

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2. the proposal to approve, on a non-binding advisory basis, the compensation to be paid to SCANA's named executive officers that is based on or otherwise relates to the merger; and

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3. the proposal to adjourn the special meeting, if necessary or appropriate, in the view of the SCANA board to solicit additional proxies in favor of the merger proposal if there are not sufficient votes at the time of the special meeting to approve the merger proposal.

Recommendations of the SCANA Board

The SCANA board unanimously (i) determined that it is in the best interests of SCANA and the SCANA shareholders that SCANA enter into the merger agreement and complete the merger and the other transactions contemplated by the merger agreement on the terms and subject to the conditions set forth in the merger agreement, (ii) adopted the merger agreement and approved the transactions contemplated by the merger agreement, including the merger, (iii) directed that the approval of the merger agreement be submitted to a vote at a meeting of the SCANA shareholders and (iv) resolved to recommend that the SCANA shareholders approve the merger agreement, which we refer to as the SCANA board recommendation. For a description of factors considered by the SCANA board in making the above recommendation, see the section entitled "*The Merger—SCANA's Reasons for the Merger; Recommendation of the SCANA Board*" beginning on page 42 of this proxy statement/prospectus.

The SCANA board recommends that you vote (i) "FOR" the merger proposal, (ii) "FOR" the merger-related compensation proposal and (iii) "FOR" the adjournment proposal.

Record Date; Stock Entitled to Vote

Only holders of record of shares of SCANA common stock at the close of business on , 2018 are entitled to notice of, and to vote at, the special meeting and at any adjournment or postponement of the special meeting. We refer to this date as the record date for the special meeting. Upon written request by a SCANA shareholder, a list of SCANA shareholders entitled to vote at the special meeting will be available for inspection at SCANA's Corporate Headquarters, 100 SCANA Parkway, Cayce, South Carolina 29033, during business hours from , 2018 through the date of the special meeting. The list will also be available at the special meeting for examination by any shareholder of record of SCANA present at the special meeting.

As of the record date for the special meeting, the directors and executive officers of SCANA as a group owned and were entitled to vote shares of SCANA common stock, or approximately % of the outstanding shares of SCANA common stock on that date. SCANA currently expects that its directors and executive officers will vote their shares in favor of approval of the merger proposal, but none of SCANA's directors or executive officers have entered into any agreement obligating them to do so.

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Quorum

A quorum requires the presence, in person or by proxy, of the holders of a majority of the shares of SCANA common stock outstanding and entitled to vote. A quorum is needed to conduct the votes on the merger proposal and the merger-related compensation proposal.

Required Vote

Approval of the merger proposal requires the affirmative vote of the holders of at least two-thirds of the outstanding shares of SCANA common stock.

The merger-related compensation proposal will be approved if more votes are cast in favor of the proposal than against the proposal. Because the vote on the merger-related compensation proposal is non-binding, if the merger agreement is approved by the SCANA shareholders and the merger is completed, the compensation that is the subject of the merger-related compensation proposal, which includes amounts SCANA is contractually obligated to pay, would still be paid regardless of the outcome of the non-binding advisory vote.

The adjournment proposal will be approved if more votes are cast in favor of the proposal than against the proposal.

Abstentions and Broker Non-Votes

Your failure to vote, or failure to instruct your broker, bank or other nominee to vote, or your abstention from voting, will have the same effect as a vote against the merger proposal, but will not be counted as a vote "for" or "against" the merger-related compensation proposal or the adjournment proposal.

Voting at the Special Meeting

Whether or not you plan to attend the special meeting, please promptly vote your shares of SCANA common stock by submitting a proxy to ensure your shares are represented at the meeting. You may also vote in person at the special meeting.

Voting in Person

An admission ticket or proof of share ownership as of the record date is required to attend the special meeting in person. If you plan to use the admission ticket, please remember to detach the admission ticket from your proxy card before mailing your proxy card. If you forget to bring the admission ticket, you will be admitted to the special meeting only if you are listed as a shareholder of record as of the record date and you bring proof of identification. If you hold your shares through a broker, bank or other nominee, you must provide proof of ownership by bringing either a copy of the voting instruction card provided by your broker, bank or other nominee or a brokerage statement showing your share ownership as of the record date. If you are a shareholder of record and your shares are owned jointly and you need an additional admission ticket, you should contact the SCANA Corporate Secretary, SCANA Corporation, 220 Operation Way, Mail Code D133, Cayce, South Carolina 29033, or call 803-217-7568.

You may vote in person at the special meeting by submitting your signed proxy card or requesting a ballot at the special meeting. Please note, however, that if your shares of SCANA common stock are held in "street name," which means your shares of SCANA common stock are held of record by a broker, bank or other nominee, and you wish to vote at the special meeting, you must bring to the special meeting a "legal proxy" from the record holder (your broker, bank or other nominee) of the shares of SCANA common stock authorizing you to vote at the special meeting.
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Voting by Proxy

You should vote your proxy even if you plan to attend the special meeting. You can always change your vote at the special meeting or revoke your proxy before the special meeting.

Your enclosed proxy card includes specific instructions for voting your shares of SCANA common stock. SCANA's electronic voting procedures are designed to authenticate your identity and to ensure that your votes are accurately recorded. When the accompanying proxy is returned properly executed, the shares of SCANA common stock represented by it will be voted at the special meeting or any adjournment or postponement thereof in accordance with the instructions contained in the proxy.

If you return your signed proxy card without indicating how you want your shares of SCANA common stock to be voted with regard to a particular proposal, your shares of SCANA common stock will be voted in favor of each such proposal. Proxy cards that are returned without a signature will not be counted as present at the special meeting and cannot be voted.

If your shares of SCANA common stock are held in an account with a broker, bank or other nominee, you have received a separate voting instruction card in lieu of a proxy card and you must follow those instructions in order to vote.

Changing or Revoking Your Proxy or Voting Instructions

You have the power to change your vote (i.e., revoke your proxy) at any time before your proxy is voted at the special meeting. If you are a shareholder of record (i.e., you hold your shares directly in your name), you may accomplish this by granting a new proxy (by telephone, Internet or mail) bearing a later date or by attending the special meeting and voting in person (each of which automatically revokes the earlier proxy). However, your attendance at the special meeting alone will not revoke any proxy that you have previously given. If you hold your shares in "street name," you must follow the instructions on the voting instruction card you received from your broker, bank or other nominee in order to change or revoke your instructions.

Solicitation of Proxies

SCANA has engaged Georgeson, Inc. to assist in the solicitation of proxies for the special meeting and has agreed to pay them a fee of approximately $ for their services plus associated costs and expenses. In addition to the use of the mail, proxies may be solicited by officers and directors and regular employees of SCANA, without additional remuneration, by personal interview, telephone, facsimile or otherwise. SCANA will also request brokers, banks and nominees to forward proxy materials to the beneficial owners of shares of SCANA common stock held of record on the record date and will provide customary reimbursement to such firms for the cost of forwarding these materials.

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THE MERGER

Effects of the Merger

Upon completion of the merger, Merger Sub will be merged with and into SCANA. SCANA will be the surviving corporation.

At the effective time of the merger, each share of SCANA common stock, without par value, issued and outstanding immediately prior to the effective time of the merger (other than cancelled shares), whether represented by a SCANA stock certificate or in non-certificated form and represented by book-entry, will be automatically converted into the right to receive the merger consideration.

Dominion Energy will not issue fractional shares of Dominion Energy common stock in the merger. Instead, each SCANA shareholder who would otherwise be entitled to receive fractional shares of Dominion Energy common stock in the merger (after aggregating all fractional shares of Dominion Energy common stock issuable to such holder) will be entitled to an amount of cash, without interest, rounded to the nearest cent, equal to the product of (i) the amount of such fractional shares of Dominion Energy common stock issuable to such holder and (ii) the volume-weighted average price, rounded to four decimal places, of Dominion Energy common stock for the ten (10) consecutive trading days ending on and including the second (2nd) trading day prior to the effective time of the merger, which we refer to as the average price.

Background of the Merger

In 2007, lawmakers in South Carolina passed the BLRA which was intended to encourage investment in nuclear construction by enabling electric utilities to finance that investment by commencing to recover financing costs incurred during construction rather than having to wait until the units were placed into service. In 2008, SCE&G and Santee Cooper announced plans to construct the two Westinghouse AP1000 Advanced Passive Safety nuclear units in Jenkinsville, South Carolina which would serve as the centerpiece of the NND project. In 2009, the SCPSC approved SCE&G's combined application pursuant to the BLRA and other laws seeking a certificate of environmental compatibility and public convenience and necessity and for a base load review order relating to the proposed construction and operation by SCE&G and Santee Cooper of the two nuclear units contemplated by the NND project. In 2012, SCE&G and Santee Cooper received a Combined Operating License from the Nuclear Regulatory Commission with respect to the NND project, and in 2013, SCE&G and Santee Cooper officially commenced nuclear construction on the two nuclear units that were the centerpiece of the NND project.

Senior management of SCANA and the SCANA board regularly review and discuss SCANA's business strategies and prospects.

In late 2016, in light of then-current facts and circumstances related to the electric and gas utility industries in general and SCANA in particular, senior management of SCANA and the SCANA board began preliminary preparations with respect to a process to proactively explore the possibility of a potential strategic transaction. These preliminary preparations included high-level discussions with Mayer Brown LLP, SCANA's outside legal counsel which we refer to as Mayer Brown, and with Morgan Stanley and RBC Capital Markets, although neither Morgan Stanley nor RBC Capital Markets was formally engaged by SCANA as a financial advisor in connection with exploring the possibility of a potential strategic transaction at this time. These discussions included consulting with Morgan Stanley and RBC Capital Markets regarding certain third parties that Morgan Stanley and RBC Capital Markets would suggest contacting regarding their interest in a potential strategic transaction involving SCANA if the SCANA board elected to commence a process to explore the possibility of a potential strategic transaction. In mid December 2016, the SCANA board, having completed these preliminary preparations, elected to defer a formal decision about whether or not to commence a process to explore the possibility of a potential strategic transaction until early January 2017. However, in late December 2016 there
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were developments that raised questions about the financial well-being of Westinghouse Electric Company LLC, which we refer to as Westinghouse, the primary contractor on the NND project with which SCE&G had a fixed price contract for Westinghouse's services in connection with the construction of the NND project. In light of these developments, the SCANA board elected in early January 2017 not to commence a process to explore the possibility of a potential strategic transaction.

On March 29, 2017, Westinghouse filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code and, in doing so, indicated an intention to reject the fixed price contract with SCE&G for Westinghouse's services in connection with the construction of the NND project. In connection therewith, SCE&G and Santee Cooper entered into an Interim Assessment Agreement with Westinghouse concerning the NND project. This agreement was designed to allow for a transition and evaluation period during which SCE&G and Santee Cooper could continue to make progress on the NND project.

Westinghouse's circumstances led SCANA to undertake an extensive analysis of possible alternatives then available for the NND project. In the months following the Westinghouse bankruptcy filing, in addition to extensively analyzing possible alternatives available for the NND project, senior management of SCANA and the SCANA board also considered various strategic alternatives available to SCANA under the circumstances.

In late March 2017, the chief executive officer of another utility company, which we refer to as Party A, approached Kevin B. Marsh, who was at that time the Chairman of the Board, President and Chief Executive Officer of SCANA, at an industry event they were both attending and told Mr. Marsh that Party A would be interested in talking to SCANA if SCANA decided at some point that it was interested in potentially pursuing a strategic transaction. Mr. Marsh informed D. Maybank Hagood, who was at that time the lead independent director of the SCANA board, of this conversation shortly after it occurred and then informed the SCANA board of this conversation at the next regularly scheduled board meeting on April 27, 2017.

On May 5, 2017, Mr. Marsh and Thomas F. Farrell II, Dominion Energy's Chairman, President and Chief Executive Officer, met in Columbia, South Carolina. The meeting was arranged at the request of Mr. Farrell. At this meeting, Mr. Farrell conveyed to Mr. Marsh various concepts and potential terms related to a potential strategic transaction between SCANA and Dominion Energy. These concepts and terms, which Mr. Farrell indicated did not constitute an offer with respect to a potential transaction, included, among other things, preliminary indications regarding the potential consideration (consisting of up to 50% cash and the remainder Dominion Energy common stock and reflecting in total a premium of approximately 15% over the recent price of SCANA common stock) that would be received by SCANA's shareholders in connection with the transaction. Mr. Marsh told Mr. Farrell that SCANA was still in the process of evaluating the NND project and that he would get back to him when the evaluation process was substantially complete.

Later on May 5, 2017, a telephonic meeting of the SCANA board was held. Members of SCANA's senior management and representatives of Mayer Brown attended the meeting. At this meeting Mr. Marsh described for the SCANA board the meeting he had with Mr. Farrell earlier that day. The SCANA board discussed whether, in light of the preliminary interest in a potential strategic transaction expressed by Dominion Energy, it was prudent to commence a process to explore the possibility of a potential strategic transaction. In light of the considerable uncertainty surrounding the NND project and the challenges that third parties would have in valuing SCANA in light of those uncertainties, the SCANA board elected not to do so at that time.

On May 12, 2017, in a meeting arranged by Mr. Marsh, Mr. Marsh had a conversation with the chief executive officer of another utility company, which we refer to as Party B, and asked whether Party B might be interested in acquiring an ownership interest in the NND project. The chief executive officer responded that Party B would consider the matter. On May 22, 2017, the chief executive officer of Party B informed Mr. Marsh that Party B was not interested in acquiring an ownership interest in the NND project.

In mid-June 2017, Mr. Marsh called Mr. Farrell, telling him that SCANA's evaluation of the NND project was taking longer than expected and that he still planned to get back to him with respect to the conceptual
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proposal made by Mr. Farrell at their meeting on May 5, 2017 after more progress was made in the evaluation of the NND project.

On June 26, 2017, SCANA and Santee Cooper announced that the Interim Assessment Agreement with Westinghouse concerning the NND project had been amended to extend the term of the agreement through August 10, 2017. The agreement extension allowed SCANA and Santee Cooper additional time to maintain their options by continuing construction on the NND project, while examining relevant information for a thorough and careful assessment to determine the most prudent path forward.

On July 12, 2017, Mr. Marsh and Jimmy E. Addison, who was at that time the Executive Vice President and Chief Financial Officer of SCANA, met with Mr. Farrell and Mark F. McGettrick, Dominion Energy's Executive Vice President and Chief Financial Officer, in Columbia, South Carolina. The meeting was arranged at the request of Mr. Marsh. At the meeting, Mr. Marsh stated that he was not going to respond to the conceptual proposal communicated by Mr. Farrell at their meeting on May 5, 2017, but rather wanted to provide Dominion Energy with an update regarding SCANA's evaluation of the NND project and to convey to Dominion Energy certain additional information about SCANA's situation and circumstances and about Santee Cooper and its generation needs for the future. Mr. Marsh asked Mr. Farrell if Dominion Energy had any interest in acquiring all or a portion of Santee Cooper's interest in the NND project. Mr. Farrell said that Dominion Energy had no such interest. Rather, Mr. Farrell stated that Dominion Energy was interested in proceeding with a due diligence review for a strategic transaction with SCANA. Mr. Marsh responded that SCANA was not prepared to proceed with that step at that time. The participants in the meeting then discussed certain of the terms that would need to be considered if the parties were to proceed to evaluate a strategic transaction. At the end of this meeting, the representatives of SCANA and Dominion Energy agreed to keep in touch as developments warranted.

On July 17, 2017, an in-person meeting of the SCANA board was held. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley and RBC Capital Markets attended this meeting. At this meeting, the SCANA board engaged in an extensive evaluation and discussion of various alternatives available for the NND project: complete both units, complete one unit and abandon (or postpone further construction of) the other unit or abandon both units. The SCANA board noted that its decision with respect to these three alternatives was heavily dependent on Santee Cooper's decision regarding its interest in the NND project. Also at that meeting, Mr. Marsh described to the SCANA board the meeting with the representatives of Dominion Energy on July 12, 2017 and further discussions ensued among the directors, management and the advisors regarding the NND project, the meeting with Dominion Energy and other related matters. After discussion, the SCANA board concluded not to pursue further discussions with Dominion Energy or others regarding a strategic transaction at that time.

On July 27, 2017, SCANA and Santee Cooper issued a joint press release that stated, among other things, that there were significant challenges to completing construction of one or both units of the NND project.

On July 31, 2017, Santee Cooper announced its decision to suspend construction of the NND project. Later on July 31, 2017, following a telephonic meeting of the SCANA board, SCE&G announced that, in light of its analysis and evaluation of the NND project and Santee Cooper's decision to suspend construction, it would cease construction on the NND project. This announcement led various stakeholders, including rate payers, shareholders, legislative committees, regulators, and other government officials, to commence inquiries into, and in some cases legal challenges with respect to, SCANA's decision to cease construction on the NND project, many of which inquiries and legal challenges remain ongoing.

On August 1, 2017, SCE&G presented the results of its evaluation of the costs necessary to complete the NND project and the basis of its decision to abandon the project in an Allowable Ex Parte Communication Briefing to the SCPSC and filed a petition with the SCPSC under the BLRA seeking, among other things, recovery of certain costs related to the construction of the NND project in light of the decision to abandon construction.
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In early August 2017, Mr. Marsh received a call from an executive of another utility company, which we refer to as Party C. During this call, the executive of Party C indicated to Mr. Marsh that Party C would be interested in talking to SCANA if SCANA was interested in pursuing a strategic transaction. At about that time, the chief executive officer of Party A also contacted Mr. Marsh and re-expressed Party A's interest in discussing a strategic transaction with SCANA if SCANA was interested in such a transaction. Also at about that time, Mr. Marsh had a conversation with the chief executive officer of Party B in which Party B did not raise the topic of a possible strategic transaction with SCANA. Mr. Marsh informed the SCANA board of these conversations shortly after they took place.

On August 15, 2017, SCE&G voluntarily withdrew the petition it had filed with the SCPSC on August 1, 2017 under the BLRA in response to concerns raised by various stakeholders with respect to the petition, and to allow adequate time for governmental officials to conduct their reviews.

On September 26, 2017, the office of Alan Wilson, the Attorney General for the State of South Carolina, issued an opinion of Robert D. Cook, the Solicitor General for the State of South Carolina, contending, among other things, that the BLRA was "suspect" under the Constitution of the United States and the Constitution of the State of South Carolina.

Following up on a telephone call from Mr. Farrell on September 29, 2017, on October 1, 2017, Mr. Marsh and Mr. Addison met with Mr. Farrell and Mr. McGettrick in Columbia, South Carolina at Mr. Farrell's request. At this meeting, Mr. Farrell conveyed to Mr. Marsh and Mr. Addison various concepts and potential terms related to a potential strategic transaction between SCANA and Dominion Energy. These concepts and terms, which Mr. Farrell indicated did not constitute an offer with respect to a potential transaction, were intended to address the various issues that had arisen since SCE&G announced it was abandoning the NND project. These concepts and terms included consideration to SCANA's shareholders in the form of 70% Dominion Energy common stock and 30% cash, reflecting in total a premium of approximately 20% over the recent price of SCANA common stock, and an immediate rate credit for SCE&G's customers, maintenance of rates related to the NND project at or below current levels, a reduced amortization period for SCANA's investment in the NND project and a write-off of a portion of that investment. The transaction would involve expedited due diligence and would be subject to regulatory approval of the terms. At the end of the meeting, Mr. Marsh told Mr. Farrell and Mr. McGettrick that SCANA's situation was very complex and involved a number of variables and considerations; however, Mr. Marsh also said that SCANA's board and management would consider what Mr. Farrell and Mr. McGettrick had conveyed and get back to them.

On October 4, 2017, Mr. Marsh called Mr. Farrell and told him that he would be presenting what Dominion Energy had conveyed at the October 1, 2017 meeting to the SCANA board. Mr. Marsh reiterated to Mr. Farrell that SCANA's present circumstances that had arisen out of the abandonment of the NND project were very complex and involved a number of variables and considerations.

Also on October 4, 2017, Mr. Marsh received a telephone call from the chief executive officer of Party A. The chief executive officer told Mr. Marsh that Party A had been separately approached about a potential purchase of Santee Cooper and wanted to discuss the potential for SCANA and Party A to also engage in a strategic transaction. The chief executive officer of Party A also asked that SCANA agree to exclusivity obligations to restrict SCANA from seeking or negotiating with other parties regarding a strategic transaction and indicated that Party A would be unwilling to make a proposal to SCANA at that time without such exclusivity terms. Mr. Marsh asked if there were any concepts or terms related to such a potential transaction involving SCANA that Party A was able to provide and the chief executive officer of Party A responded that Party A had no such concepts or terms to provide at that time, but that they were working on several ideas.

On October 6, 2017, a representative of Party C again indicated to Mr. Marsh in a meeting requested by the representative that Party C would be interested in talking to SCANA about a potential strategic transaction if
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SCANA was interested in considering such a transaction, but the representative did not propose any concepts or terms that would apply to such a possible transaction or any process that would apply to the consideration of such a transaction.

An in-person meeting of the SCANA board was held on October 6, 2017. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley and RBC Capital Markets attended this meeting. At this meeting, Mr. Marsh described for the SCANA board the recent discussions with each of Dominion Energy, Party A and Party C. The SCANA board, together with SCANA's management, Morgan Stanley, RBC Capital Markets and Mayer Brown, then discussed whether it was prudent to commence a limited process to identify potential acquirors of SCANA at that time. After weighing the considerations involved and the consequences of commencing such a process, the SCANA board determined to move forward with exploring the possibility of a strategic transaction with Dominion Energy and with Party A, including providing due diligence information to each of Dominion Energy and Party A, and authorized SCANA's management and advisors to proceed accordingly. After the representatives of Morgan Stanley and RBC Capital Markets were excused from the meeting, representatives of Mayer Brown summarized for the SCANA board the material terms proposed by Morgan Stanley and RBC Capital Markets regarding their respective engagements as a financial advisor to SCANA in connection with a possible strategic transaction.

After the conclusion of the meeting of the SCANA board on October 6, 2017, Mr. Marsh called Mr. Farrell to inform him of the SCANA board's decision to proceed to explore a potential transaction with Dominion Energy (without any exclusivity obligations on SCANA) and called the chief executive officer of Party A to inform the chief executive officer of the SCANA board's decision to proceed to explore a potential transaction with Party A (without any exclusivity obligations on SCANA).

On October 8, 2017, SCANA entered into a confidentiality agreement with Dominion Energy and a confidentiality agreement with Party A. Each of such confidentiality agreements contained standstill provisions which, among other things, restricted the ability of Dominion Energy and Party A to acquire or offer to acquire any SCANA securities and to submit any proposal or offer relating to a business combination with SCANA without the SCANA board's prior written consent, except that the standstill restrictions would terminate (other than those relating to acquisitions of SCANA securities) in the event that SCANA announced it had entered into a definitive agreement relating to a strategic transaction. In connection with or prior to entering into such confidentiality agreements, each of Dominion Energy and Party A sought restrictions on SCANA's ability to seek or negotiate with other parties regarding a possible strategic transaction, but SCANA did not agree to any such restrictions. Shortly thereafter, Dominion Energy and Party A were granted access to a data room and a due diligence process was commenced with Dominion Energy and with Party A.

On October 10, 2017, the chief executive officer of Party B called Mr. Marsh and indicated that Party B did not have any interest in acquiring an interest in the NND project but that Party B was willing to talk with SCANA about a potential strategic transaction if SCANA was considering strategic options. The chief executive officer of Party B did not propose any concepts or terms that would apply to such possible transaction or any process that would apply to the consideration of such a transaction.

Also, on October 10, 2017, Mr. Marsh, Mr. Addison and Jim O. Stuckey, SCANA's Senior Vice President and General Counsel, met with the chief executive officer and other representatives of Party A in Columbia, South Carolina. At this meeting, the representatives of Party A conveyed some of the benefits and opportunities that might result from a potential strategic transaction between SCANA and Party A and indicated that a combination of Party A and SCANA would involve SCANA's shareholders receiving solely the common stock of Party A in the transaction. The chief executive officer of Party A stated that Party A was not in the position at that time to indicate the amount of consideration SCANA's shareholders would receive. The chief executive officer again requested that SCANA agree to exclusivity obligations restricting SCANA's ability to seek or negotiate with other parties regarding a potential strategic transaction.

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A telephonic meeting of the SCANA board was held on October 12, 2017. Members of SCANA's senior management and representatives of Mayer Brown attended this meeting. At this meeting, Mr. Marsh described for the SCANA board the recent telephone call with Party B, recent meeting with Party A and recent communications from Dominion Energy indicating its desire to move forward with discussions expeditiously. Also, representatives of Mayer Brown summarized for the SCANA board certain matters related to the proposed engagements of Morgan Stanley and RBC Capital Markets as SCANA's financial advisors, including the material proposed terms for such engagements and the disclosures made by Morgan Stanley and RBC Capital Markets with respect to their respective material relationships with Dominion Energy, Party A, Party B and Party C. In consultation with Mayer Brown, the SCANA board determined that none of such relationships of SCANA's financial advisors were sufficiently material to adversely affect the ability of Morgan Stanley or RBC Capital Markets to act as financial advisors to SCANA in connection with a potential strategic transaction.

On October 13, 2017, the SCANA board, acting by written consent, approved the engagements of Morgan Stanley and RBC Capital Markets to serve as financial advisors to SCANA in connection with a possible strategic transaction and SCANA subsequently engaged each of Morgan Stanley and RBC Capital Markets.

Throughout October and November 2017, Dominion Energy conducted due diligence on SCANA and SCANA conducted reverse due diligence on Dominion Energy. However, no significant negotiation of terms of a potential strategic transaction between SCANA and Dominion Energy occurred during this time.

In mid-October 2017, Party A's chief executive officer told Mr. Marsh that, in light of the considerable uncertainty resulting from SCE&G's decision to abandon the NND project, including uncertainty regarding future electric rates, Party A was not able to narrow a valuation range for SCANA. Subsequent to this, Party A did not continue participation in the due diligence process and ceased to communicate interest in a potential strategic transaction with SCANA.

An in-person meeting of the SCANA board was held on October 24, 2017. Members of SCANA's senior management and representatives of Mayer Brown attended this meeting. Among other things discussed at this meeting, the SCANA board discussed the status of discussions with Dominion Energy and Party A as well as the status of SCANA's analysis of a potential strategic transaction more generally.

A telephonic meeting of the SCANA board was held on October 26, 2017. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley and RBC Capital Markets attended this meeting. Mr. Marsh informed the SCANA board of developments with respect to SCANA's consideration of a potential strategic transaction. Mr. Marsh explained that SCANA had primarily been focused on trying to reach a settlement on rates and other regulatory matters resulting from the decision to abandon the NND project and participating in legislative hearings related to the same and further discussions ensued among the directors, management and the advisors regarding the potential for a strategic transaction with Dominion Energy and regulatory and related matters. After discussion, the SCANA board concluded that it was prudent to continue to seek a rate settlement and also to continue discussions with Dominion Energy on a parallel path.

On October 31, 2017, SCANA announced that Mr. Marsh would retire as the chief executive officer of SCANA and SCE&G and that on January 1, 2018 Mr. Addison would become chief executive officer of SCANA and SCE&G, among other leadership changes.

On November 16, 2017, SCE&G publicly proposed a $4.8 billion comprehensive solution to outstanding rate and regulatory issues relating to the abandoned NND project. Based on the reaction from legislators and other stakeholders to the proposal, it quickly became clear that this proposal was not a viable solution to the rate and regulatory issues relating to the abandoned NND project.

During the week of November 20, 2017, Mr. McGettrick and Mr. Addison spoke on multiple occasions by telephone. Among other things discussed between Mr. McGettrick and Mr. Addison, Mr. McGettrick told
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Mr. Addison that Dominion Energy was considering providing an updated proposal to SCANA regarding a potential strategic transaction.

On November 27, 2017, at the request of Mr. Farrell, Mr. Marsh, Mr. Addison and Mr. Hagood met with Mr. Farrell and Mr. McGettrick in Columbia, South Carolina. At this meeting, Mr. Farrell conveyed a proposal with respect to a potential strategic transaction between SCANA and Dominion Energy, which Mr. Farrell stated did not constitute an offer for a potential transaction. Key terms of this proposal included consideration to SCANA's shareholders in the form of 75% to 80% Dominion Energy common stock and 20% to 25% cash, reflecting in total a premium of approximately 30% over the recent price of SCANA common stock, the retention of SCE&G's headquarters in South Carolina and an updated plan for the regulatory resolution of the NND project which continued to include immediate cash refunds to SCE&G customers, prospective customer bill reductions for the NND project, a reduced amortization period for investments in the NND project, and a partial write-off of capital spent on the NND project. The representatives of SCANA told Mr. Farrell and Mr. McGettrick that the proposal would be shared with the SCANA board.

A telephonic meeting of the SCANA board was held on November 29, 2017. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley and RBC Capital Markets attended this meeting. Mr. Addison summarized the terms of the proposal conveyed by Dominion Energy on November 27, 2017. Mr. Addison expressed his view that in light of the current issues, risks and challenges facing SCANA, the Dominion Energy proposal merited further consideration. Mr. Marsh agreed with that assessment. The SCANA board then unanimously concluded that the Dominion Energy proposal warranted further consideration and authorized SCANA's management and advisors to pursue discussions with Dominion Energy accordingly.

On December 1, 2017, Mayer Brown provided to Dominion Energy an initial draft of a merger agreement with respect to a potential strategic transaction between SCANA and Dominion Energy. From this time until January 2, 2018, SCANA, Dominion Energy and their respective advisors, including McGuireWoods LLP, Dominion Energy's outside legal counsel which we refer to as McGuireWoods, had extensive negotiations with respect to the terms of the proposed merger agreement.

On December 5, 2017, an in-person due diligence session was held in Richmond, Virginia between representatives of SCANA and representatives of Dominion Energy. Also on December 5, 2017, representatives of SCANA and Dominion Energy met to discuss the timeline for a potential transaction and the terms of Dominion's proposal.

A telephonic meeting of the SCANA board was held on December 8, 2017. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley and RBC Capital Markets attended this meeting, as did a representative of McNair Law Firm, P.A., SCANA's South Carolina corporate counsel which we refer to as McNair. At this meeting, SCANA's management discussed the due diligence Dominion Energy was conducting on SCANA, the status of Dominion Energy's review of the proposed merger agreement, the proposed timeline for a potential transaction with Dominion Energy and the terms of Dominion Energy's anticipated updated proposal. After that discussion, at the request of the SCANA board, the representatives of Morgan Stanley and RBC Capital Markets indicated that they were unaware of any material change in their respective institution's material relationships disclosure previously provided to the SCANA board and that an updated material relationships disclosure would be provided before the next meeting of the SCANA board. Then, at the request of the SCANA board, each of Mayer Brown and McNair confirmed that their respective firms did not have a conflict of interest in representing SCANA in a transaction with Dominion Energy. SCANA's financial advisors then provided an overview of, among other things, (a) Dominion Energy's historical share price performance for the last three years, (b) Dominion Energy's capital expenditures plan, key earnings drivers and master limited partnership structure as provided by Dominion Energy's management, (c) certain financial projections provided by Dominion Energy's management relating to Dominion Energy for fiscal years 2017 through 2022, and (d) based on publicly available information and the projections provided by Dominion Energy, Dominion Energy's credit profile. Next, Iris N. Griffin, who was at that time the Vice President of Finance and

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Treasurer of SCANA, made a presentation of SCANA's forecasted earnings per share growth rates, which had been prepared by SCANA management, using various rate and regulatory settlement scenarios. Such scenarios did not take into account potential federal tax reform given the uncertainty with respect to such reform at that time. Following Ms. Griffin's presentation, representatives of Mayer Brown provided the SCANA board an overview of the terms of the proposed merger agreement, including, among other things, a description of the structure of the transaction, the closing conditions of the parties, the obligations of the parties with respect to pursuing regulatory approvals and the terms restricting SCANA's ability to solicit alternative transactions. At the end of the meeting, representatives of Mayer Brown reviewed with the members of the SCANA board their fiduciary duties under applicable law and asked the members of the SCANA board to provide updated information regarding past or current business or personal relationships with Dominion Energy or individuals associated with Dominion Energy in order to determine whether any potential conflicts of interest existed.

Also on December 8, 2017, McGuireWoods sent Mayer Brown a revised draft of the merger agreement that included, among other changes, a closing condition providing that the key terms related to the rate settlement would receive SCPSC approval with no deviation in terms from those proposed by Dominion Energy in connection with the merger.

On December 15, 2017, Dominion Energy provided SCANA with an updated proposal with respect to a potential strategic transaction between SCANA and Dominion Energy. This updated proposal reflected the due diligence that Dominion Energy had conducted on SCANA as well as the various discussions among the parties and their respective advisors to that point. Key terms of this updated proposal included: an all-stock, tax deferred transaction with a value of $54.50 per share of SCANA common stock (based on recent market prices of Dominion Energy common stock) reflecting an implied premium of approximately 27.9% over the closing price of SCANA common stock prior to a November 27, 2017 media report that SCANA had retained Morgan Stanley to explore strategic alternatives, various commitments by Dominion Energy to SCANA's community including a commitment to maintain SCE&G's headquarters in South Carolina, immediate cash refunds to customers totaling approximately $1.3 billion, which Dominion Energy estimated would result in an average refund of approximately $1,000 for residential customers, a 3.5% bill reduction related to the NND project going forward, a substantial write down of the investment in the NND project and exclusion from rate base of a gas-fired generation facility being acquired to help replace the NND project. The updated proposal also included certain requirements of Dominion Energy in order to proceed with the transaction, including that the key terms related to the rate settlement would receive SCPSC approval with no material changes in the terms of the rate settlement proposal and no change to the economic value of the rate settlement proposal and that, prior to the closing of the merger, there would be no changes in laws that impact SCANA, the BLRA or other utility laws.

An in-person meeting of the SCANA board was held on December 18, 2017. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley, RBC Capital Markets and McNair attended this meeting. Also attending a portion of the meeting were representatives from SCANA's various regulatory counsel in connection with the proposed transaction. After some introductory matters, the meeting commenced with regulatory counsel providing the SCANA board with an overview of the various regulatory clearances that would be needed in connection with the proposed transaction, including the likely timing for seeking and obtaining such clearances and the possibility of issues arising in obtaining such clearances. After regulatory counsel was excused from the meeting, representatives of Mayer Brown discussed with the SCANA board, as it had done in prior board meetings, information that the directors had provided regarding past or current business or personal relationships with Dominion Energy or individuals associated with Dominion Energy. After considering such relationships and in consultation with Mayer Brown, the SCANA board reaffirmed its prior determination that each director was independent and disinterested in connection with a potential strategic transaction with Dominion Energy. Mayer Brown also discussed with the SCANA board, as it had done in prior board meetings, the disclosures made by Morgan Stanley and RBC Capital Markets, which had been updated by Morgan Stanley and RBC Capital Markets prior to the meeting, with respect to their respective material relationships with Dominion Energy. After considering such relationships and in consultation with Mayer Brown, the SCANA board reaffirmed its prior determination that none of such relationships of SCANA's financial

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advisors were sufficiently material to adversely affect the ability of Morgan Stanley or RBC Capital Markets to act as financial advisors to SCANA in connection with a potential strategic transaction with Dominion Energy.

Next, Ms. Griffin made a presentation of SCANA's financial projections, which had been prepared by SCANA's management, using various rate and regulatory settlement scenarios. Such scenarios took into account the potential consequences of federal tax reform given the additional certainty with respect to such reform at that time. Then, each of Morgan Stanley and RBC Capital Markets discussed certain preliminary financial information relating to SCANA and the proposed transaction. Next, representatives of Mayer Brown, Morgan Stanley and RBC Capital Markets provided an update on the reverse due diligence that had been conducted on Dominion Energy and representatives of Mayer Brown summarized for the SCANA board certain key open issues in the merger agreement. The meeting concluded with Mr. Stuckey explaining to the SCANA board the terms of the change of control plans covering SCANA officers in the event a transaction was consummated.

On December 19, 2017, Mr. Addison had a meeting with an executive of Party C that had been arranged at the request of that executive. At that meeting, the executive indicated that Party C had a long-term interest in acquiring SCANA. The executive did not however propose any concepts or terms that would apply to a transaction between SCANA and Party C or any process that would apply to consideration of such a transaction. The executive also indicated that Party C would be interested in acquiring Public Service Company of North Carolina, a subsidiary of SCANA, for $2.2 billion. Mr. Addison informed the executive that he would present these matters to the SCANA board and would respond to the executive if and as directed by the SCANA board.

A telephonic meeting of the SCANA board was held on December 19, 2017. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley, RBC Capital Markets and McNair attended this meeting. At this meeting, Mr. Addison reported on his recent meeting with an executive of Party C. Mr. Addison explained that, in his view, Party C's proposal to acquire SCANA's subsidiary, Public Service Company of North Carolina, was not particularly attractive given the valuation proposed by Party C and the fact that Public Service Company of North Carolina was a key driver of SCANA's growth. The SCANA board concurred with this assessment. SCANA's management and advisors then discussed with the SCANA board certain significant open issues with respect to the merger agreement with Dominion Energy, including the triggers for and amount of the reverse termination fee payable by Dominion Energy, certain deal protection terms, including the amount of the termination fee payable by SCANA, closing conditions relating to South Carolina regulatory approvals and changes that cannot be considered in determining whether a material adverse effect on SCANA has occurred. After discussion, the SCANA board provided SCANA's management and advisors with guidance on these issues.

Later on December 19, 2017, SCANA, through its financial advisors, had a discussion with Dominion Energy regarding various potential methods to determine a mutually acceptable reference stock price for each party for calculating the fixed exchange ratio, as well as with respect to other open issues. SCANA's proposed method for calculating the exchange ratio reflected a value of $57 per share of SCANA common stock.

On December 21, 2017, SCANA's stock price declined approximately 9.5%. On the following day, SCANA's stock price rose approximately 4.3%.

On December 22, 2017, McGuireWoods circulated a revised draft of the merger agreement on behalf of Dominion Energy. Among other changes, the revised draft reflected a closing condition that provided Dominion Energy the right not to close the transaction if after the signing of the merger agreement there were any changes to the BLRA or other South Carolina public utility laws and a termination fee amount of 3.5% of the equity value of the transaction for each of the termination fee payable by SCANA in certain instances and the termination fee payable by Dominion Energy in certain instances.

On December 27, 2017, Dominion Energy revised its proposal to, among other changes, increase the initial bill reduction to customers to at least 5% from the prior proposal of 3.5%. This increased benefit to customers

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was attributed to Dominion Energy passing through to customers the benefits associated with the recently enacted reduction in federal income tax rates (estimated at the time to be at least 1.5%). Also on December 27, 2017, Dominion Energy proposed establishing the proposed transaction value through a fixed exchange ratio of 0.6620 of a share of Dominion Energy common stock for each outstanding share of SCANA common stock.

A telephonic meeting of the SCANA board was held on December 29, 2017. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley, RBC Capital Markets, McNair and a representative of Womble Bond Dickinson, LLP, SCANA's South Carolina regulatory counsel which we refer to as Womble Bond, attended this meeting. At this meeting, each of Morgan Stanley and RBC Capital Markets discussed with the SCANA board certain preliminary financial matters related to SCANA and the proposed transaction, including an update with respect to the negotiations on the exchange ratio. Following such discussion, Mr. Stuckey and representatives of Mayer Brown summarized the remaining significant open issues in the merger agreement and the representatives of Mayer Brown summarized the material terms of the merger agreement for the SCANA board. Among other material terms, Mayer Brown summarized the terms of the merger agreement relating to employee benefits and executive compensation, including treatment of equity and equity-based awards, post closing covenants relating to treatment of employees and employee benefits, including protection of severance benefits and the period of post-closing protection, and the proposed exceptions to the interim operating covenants, including salary increases, ordinary course equity grants, and retention bonuses. The representative of Womble Bond then summarized the material terms of the merger agreement relating to South Carolina regulatory matters and the rate settlement proposal.

Later on December 29, 2017, SCANA, through its financial advisors, conveyed a counterproposal to Dominion Energy with respect to the transaction consideration of an exchange ratio of 0.6690 of a share of Dominion Energy common stock for each outstanding share of SCANA common stock.

On December 30, 2017, Dominion Energy agreed to SCANA's counterproposal on the proposed exchange ratio of 0.6690 of a share of Dominion Energy common stock for each outstanding share of SCANA common stock. On December 31, 2017, the parties also reached agreement on certain of the other significant open issues, including that the merger agreement would include a closing condition that provided Dominion Energy the right not to close the transaction if after the signing of the merger agreement there were any substantive changes to the BLRA or other South Carolina public utility laws that would have an adverse effect on SCANA and a termination fee in the amount of 3.0% of the offered equity value of the transaction for the termination fee payable by SCANA in certain instances and a termination fee in the amount of 3.5% of the offered equity value of the transaction for the termination fee payable by Dominion Energy in certain instances. Counsel for the parties then completed final documentation reflecting these agreements.

A telephonic meeting of the SCANA board was held on January 2, 2018. Members of SCANA's senior management and representatives of Mayer Brown, Morgan Stanley, RBC Capital Markets and McNair attended this meeting. At this meeting, SCANA's management and financial advisors provided the directors with an update of the final negotiations with respect to the exchange ratio and representatives of Mayer Brown summarized the resolution of the remaining significant open issues in the merger agreement. Then, Morgan Stanley and RBC Capital Markets separately provided the SCANA board with their respective financial analyses performed in connection with the proposed transaction. Next, Mr. Addison, Ms. Griffin, Mr. Stuckey and other members of SCANA management shared with the SCANA board their views on the merits of the proposed transaction with Dominion Energy and the alternatives to the transaction. Each member of management present at the meeting stated that, in his or her view, the proposed transaction with Dominion Energy was the best alternative available to SCANA under its present circumstances. The SCANA board then engaged in further discussions and deliberations, with the assistance of SCANA's management and advisors, with respect to the proposed transaction with Dominion Energy.

Next, at the request of the SCANA board, Morgan Stanley rendered its oral opinion to the SCANA board (which was subsequently confirmed in writing by delivery of Morgan Stanley's written opinion to the SCANA

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board dated the same date) to the effect that, as of January 2, 2018, and based upon and subject to the assumptions made, procedures followed, matters considered and qualifications and limitations on the scope of review undertaken by Morgan Stanley as set forth in Morgan Stanley's written opinion, the merger consideration (as such term is defined in the merger agreement) to be received by holders of SCANA common stock (other than certain excluded holders) pursuant to the merger agreement was fair from a financial point of view to such holders. Also at this meeting and at the request of the SCANA board, RBC Capital Markets rendered its oral opinion, confirmed by delivery of a written opinion dated January 2, 2018, to the SCANA board to the effect that, as of that date and based on and subject to the procedures followed, assumptions made, factors considered and qualifications and limitations described in the opinion, the merger consideration to be received by holders of SCANA common stock pursuant to the merger agreement was fair, from a financial point of view, to such holders. The full texts of the opinions of Morgan Stanley and RBC Capital Markets are attached as Annex B and Annex C, respectively, to this proxy statement/prospectus and set forth, among other things, the procedures followed, assumptions made, factors considered and qualifications and limitations on the review undertaken in connection with their respective opinions, as more fully described in the section entitled "—Opinions of SCANA's Financial Advisors."

The SCANA board then unanimously (a) determined that it is in the best interests of SCANA and the shareholders of SCANA that SCANA enter into the merger agreement and consummate the merger and the other transactions contemplated by the merger agreement on the terms and subject to the conditions set forth in the merger agreement, (b) adopted the merger agreement and approved the transactions contemplated by the merger agreement, including the merger, (c) directed that the approval of the merger agreement be submitted to a vote at a meeting of the shareholders of SCANA and (d) resolved to recommend that the shareholders of SCANA approve the merger agreement.

In the early evening of January 2, 2018, the parties executed the merger agreement.

In the early morning of January 3, 2018, SCANA and Dominion Energy issued a joint press release announcing the transaction.

SCANA's Reasons for the Merger; Recommendation of the SCANA Board

SCANA's Reasons for the Merger

At a meeting held on January 2, 2018, the SCANA board unanimously (i) determined that it is in the best interests of SCANA and the SCANA shareholders that SCANA enter into the merger agreement and complete the merger and the other transactions contemplated by the merger agreement on the terms and subject to the conditions set forth in the merger agreement, (ii) adopted the merger agreement and approved the transactions contemplated by the merger agreement, including the merger, (iii) directed that the approval of the merger agreement be submitted to a vote at a meeting of the SCANA shareholders, and (iv) resolved to recommend that the SCANA shareholders approve the merger agreement. In evaluating the merger, the SCANA board consulted with SCANA's management and legal and financial advisors and, in reaching its unanimous decision to adopt the merger agreement and to recommend that the SCANA shareholders approve the merger agreement, considered numerous factors which are discussed below.

Among the information and material factors considered by the SCANA board were the following (not in any relative order of importance):

- The understanding of SCANA's management and the SCANA board of SCANA's business, operations, financial condition, financing needs, earnings, strategy and prospects, as well as SCANA's historical and projected financial performance;
- The SCANA board's consideration of the current state of the economy, debt and equity financing markets, and uncertainty regarding near-term and long-term forecasted economic conditions, both generally and within SCANA's industry in particular;

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- The fact that, since the bankruptcy filing of Westinghouse Electric Company, LLC, which we refer to as Westinghouse, and SCANA's decision to abandon the NND project, SCANA has been under increasingly intense regulatory, political and legal scrutiny which has resulted in, and could result in further, significant financial uncertainty for SCANA and could lead to significant negative financial impacts on SCANA, including possible bankruptcy;
- The fact that the exchange ratio of 0.6690 of a share of Dominion Energy common stock for each outstanding share of SCANA common stock provided for in the merger represents:
  - an implied price of approximately $54.23 per share of SCANA common stock based on the closing price of Dominion Energy common stock on December 29, 2017, the last trading day prior to the date on which the SCANA board adopted the merger agreement, which reflects an implied premium of approximately 36.3% based on the closing price of SCANA common stock on December 29, 2017; and
  - an implied price of approximately $55.39 based on the 30-day Bloomberg intraday volume weighted average price of Dominion Energy common stock as of December 29, 2017, the last trading day prior to the date on which the SCANA board adopted the merger agreement, which reflects an implied premium of approximately 29.7% based on the 30-day Bloomberg intraday volume weighted average price of SCANA common stock as of December 29, 2017;
- The fact that SCE&G publicly proposed on November 16, 2017 a $4.8 billion comprehensive solution to outstanding rate and regulatory issues relating to the abandoned NND project and that, based on the reaction from legislators and other stakeholders to the proposal, it quickly became clear that the proposal, in the view of SCANA's management and the SCANA board, was not an acceptable solution to these issues;
- The fact that Dominion Energy committed to propose to the SCPSC, among other things, a one-time rate credit to SCE&G's electric customers equal to an aggregate of $1.3 billion, at least a 5% bill reduction from 2017 bills to SCE&G's electric customers, an approximately $1.7 billion write-off of capital and regulatory assets relating to the NND project (including a 20-year amortization period for costs associated with the NND project) and the completion of the $180 million purchase of a natural gas fired power station (the cost of which would not be included in setting rates for SCE&G's electric customers), which in the aggregate represents a significant improvement over the plan SCE&G publicly proposed on November 16, 2017 and, in the view of SCANA's management and the SCANA board, represents a comprehensive solution to outstanding rate and regulatory issues relating to the abandoned NND project that provides SCE&G's electric customers greater overall value than what SCANA could offer on a standalone basis;
- The fact that, upon completion of the merger, SCANA would become part of a much larger company with a considerably stronger balance sheet and access to greater financial resources, which should lower SCANA's cost of capital (taking into account the regulatory and political uncertainty SCANA was facing at the time the SCANA board adopted the merger agreement) and allow SCE&G the ability and resources to address and resolve the issues arising from or relating to Westinghouse's bankruptcy and the abandonment of the NND project;
- The historical trading ranges of SCANA's common stock and the potential trading range of SCANA's common stock absent announcement of the merger agreement and in light of the ongoing regulatory, political and legal scrutiny SCANA is facing;
- The fact that SCANA had conducted preliminary discussions with parties other than Dominion Energy with respect to a potential strategic transaction, none of which resulted in a proposal that set forth proposed transaction consideration or other developed terms, and the SCANA board's conclusion, based on these preliminary discussions, industry dynamics, advice and market insights received from Morgan Stanley, input and market insights of RBC Capital Markets and regulatory and other challenges for SCANA, among other factors, that the merger provided the most likely path for enhanced value for SCANA shareholders;

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- The recommendation of SCANA's senior management that SCANA should proceed with the proposed transaction based on its knowledge of SCANA's industry and the regulatory, political, legal and financial challenges facing SCANA in connection with the abandonment of the NND project;
- The results of SCANA's due diligence investigation of Dominion Energy conducted with the assistance of SCANA's management and certain of SCANA's outside advisors;
- The fact that, following the merger, SCANA's shareholders would hold stock in a combined company that will have increased scale and scope, including increased financial scale, greater diversification of markets and more regulatory jurisdictions than SCANA on a standalone basis, thereby diversifying certain risks currently associated with SCANA common stock;
- The financial analyses performed by Morgan Stanley with respect to the proposed transaction, and the opinion of Morgan Stanley, dated January 2, 2018, the full text of which is attached as Annex B, that, based upon and subject to the assumptions made, procedures followed, matters considered and qualifications and limitations on the scope of review undertaken by it, as set forth in Morgan Stanley's written opinion and as described in "*—Opinions of SCANA's Financial Advisors—Opinion of Morgan Stanley & Co. LLC*" beginning on page 47 of this proxy statement/prospectus, the merger consideration to be received by holders of SCANA common stock (other than holders of the cancelled shares) pursuant to the merger agreement was fair from a financial point of view to such holders;
- The financial presentation and opinion, dated January 2, 2018, of RBC Capital Markets to the SCANA board as to the fairness, from a financial point of view and as of such date, of the merger consideration to be received by holders of SCANA common stock pursuant to the merger agreement, the full text of which opinion is attached as Annex C to this proxy statement/prospectus and sets forth, among other things, the procedures followed, assumptions made, factors considered and qualifications and limitations on the review undertaken by RBC Capital Markets in connection with its opinion, as more fully described in the section entitled "*—Opinions of SCANA's Financial Advisors—Opinion of RBC Capital Markets, LLC*" beginning on page 58 of this proxy statement/prospectus;
- The terms and conditions of the merger agreement, including, among other things, the representations, warranties, covenants and agreements of the parties, the form and structure of the merger consideration and the termination rights of the parties;
- The fact that, while the merger agreement contains a covenant prohibiting SCANA from soliciting third-party acquisition proposals, the merger agreement permits SCANA, prior to the time that SCANA's shareholders approve the merger agreement, to discuss and negotiate, under specified circumstances, an unsolicited acquisition proposal should one be made and, if the SCANA board determines in good faith, after consultation with SCANA's financial advisors and outside legal counsel, that the unsolicited acquisition proposal constitutes a superior proposal within the meaning of the merger agreement and, after consultation with SCANA's outside legal counsel, that the failure to take any of the following actions would reasonably be expected to be inconsistent with the SCANA board's fiduciary duties under applicable law, the SCANA board is permitted, after taking certain steps, to change or withdraw its recommendation of the merger agreement in response to a superior proposal or terminate the merger agreement in order to enter into a definitive agreement for that superior proposal, subject to payment of a termination payment of $240,000,000 to Dominion Energy;
- The fact that the merger agreement allows the SCANA board, prior to the time that SCANA shareholders approve the merger agreement, to change or withdraw its recommendation of the merger agreement in response to a material event, development or change in circumstances that first becomes known to the SCANA board or certain officers of SCANA after the date of the merger agreement and which was not reasonably foreseeable as of or prior to the date of the merger agreement or which would not reasonably be expected to have become known after reasonable investigation or inquiry as of or prior to the date of the merger agreement, subject, in all cases, to specified exceptions, if the SCANA board determines in good faith, after consultation with SCANA's outside legal counsel, that

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the failure to change or withdraw its recommendation would be inconsistent with the SCANA board's fiduciary duties under applicable law;

- The fact that, in the event that the merger agreement is terminated and a regulatory approval or clearance (other than the approval or clearance of the SCPSC) is not obtained under certain circumstances specified in the merger agreement or is terminated by SCANA for a material breach by Dominion Energy of its covenants to obtain regulatory approvals or clearances with respect to the proposed transaction and that breach caused a failure of any of the closing conditions relating to regulatory matters, SCANA will be entitled to receive a termination fee of $280,000,000 from Dominion Energy;
- The likelihood that the merger will be completed based on, among other things (not in any relative order of importance):
  - the business reputation and capabilities of Dominion Energy, and the SCANA board's assessment that Dominion Energy is willing to devote the resources necessary to close the merger in an expeditious manner;
  - the termination date under the merger agreement, after which SCANA or Dominion Energy, subject to specified exceptions, may terminate the merger agreement, allowing for sufficient time to close the merger;
  - SCANA's ability to seek specific performance to prevent breaches of the merger agreement by the Dominion Energy parties and to enforce specifically the terms of the merger agreement; and
  - the exclusions from what would contribute to or constitute a material adverse effect on SCANA under the terms of the merger agreement;
- The fact that the merger is intended to qualify as a "reorganization" within the meaning of Section 368(a) of the Code, with the result that a U.S. holder of SCANA common stock generally would not recognize any gain or loss upon receipt of Dominion Energy common stock solely in exchange for SCANA common stock in the merger, except with respect to cash received in lieu of fractional shares of Dominion Energy common stock;
- The provisions of the merger agreement that require, as soon as practicable after the effective time of the merger, the appointment of a current member of the SCANA board or SCANA's executive management to the Dominion Energy board;
- The fact that the merger agreement is subject to approval by holders of at least two-thirds of the outstanding shares of SCANA common stock;
- The SCANA board's belief regarding the likelihood of obtaining the regulatory approvals, findings and clearances necessary to complete the merger; and
- The fact that the merger agreement reflects Dominion Energy's agreement to make a good faith commitment to give SCANA's employees due and fair consideration for other employment and promotion opportunities within the combined company to the extent any employment positions are re-aligned, reduced or eliminated in the future as a result of the merger; to maintain SCE&G's corporate headquarters in Cayce, South Carolina; to increase, for at least five (5) years following the merger, SCANA's historical levels of charitable contributions to certain charities to be specified by SCANA's leadership and to maintain or increase historical levels of community involvement, low income funding and economic efforts in SCANA's current operating area.

The SCANA board also considered a variety of potentially negative factors in its deliberations concerning the merger agreement and the merger, including the following (not in any relative order of importance):

- The fact that, because the merger consideration is a fixed exchange ratio of shares of Dominion Energy common stock for shares of SCANA common stock, SCANA shareholders could be adversely affected

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by a decrease in the trading price of Dominion Energy common stock and the fact that the merger agreement does not provide for any adjustment of the merger consideration if the trading price of Dominion Energy common stock decreases and does not provide a price-based termination right or other similar protection in favor of SCANA or SCANA shareholders;

- The risk that the merger will be delayed or will not be completed, including the risk that the required regulatory approvals and clearances may not be obtained or other conditions to closing in the merger agreement may not be satisfied, as well as the potential loss of value to SCANA shareholders and the potential negative impact on the financial position, operations and prospects of SCANA if the merger is delayed or is not completed for any reason;
- The fact that Dominion Energy will not be obligated to complete the merger if (i) any South Carolina public utility law including the BLRA (as in effect as of the date of the merger agreement) is substantively changed in a manner that has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries, (ii) the SCPSC fails to make a SCPSC merger determination, or (iii) unless otherwise consented to by Dominion Energy in its sole discretion, the SCPSC fails to approve the SCPSC petition without any material changes to the proposed terms, conditions or undertakings of the cost recovery plan and without a significant change to the economic value of the proposed terms set forth in the cost recovery plan, in each case as reasonably determined by Dominion Energy in good faith;
- The fact that SCANA did not conduct a formal sale process to solicit other developed acquisition proposals from parties other than Dominion Energy;
- The fact that, since Westinghouse's bankruptcy filing and SCANA's decision to abandon the NND project, SCANA's stock has been trading significantly below historical levels in the recent past, resulting in an implied premium in the merger based on a relatively low stock price;
- The fact that, by virtue of the merger, SCANA has foregone the opportunity to resolve the issues arising from or relating to Westinghouse's bankruptcy and the abandonment of the NND project on its own which, if successful, might have resulted in the price of SCANA common stock increasing to a level in excess of the merger consideration;
- The significant costs involved in connection with negotiating the merger agreement, the pursuit of regulatory approvals and otherwise completing the merger, the substantial management time and effort required to effectuate the merger and the potential disruptions to SCANA's day-to-day operations during the pendency of the merger;
- The risk, during the pendency of the merger, that SCANA's relationship with regulators, customers, employees, suppliers, agents and others with which SCANA and its subsidiaries have business dealings could be adversely affected as a result of, among other things, the restrictions in the merger agreement on the conduct of SCANA's business prior to the completion of the merger, which could delay or prevent SCANA from undertaking business opportunities that may arise or other action it would otherwise take with respect to the operations of SCANA's business;
- The fact that SCANA's executive officers and directors may have interests in the merger that are different from, or in addition to, the interests of SCANA shareholders, including the accelerated vesting of stock-based awards held by executive officers, the payment of cash severance to certain executives of SCANA if a termination of employment were to occur under specified circumstances in connection with the merger, and the interests of SCANA's directors and officers in indemnification by Dominion Energy and insurance coverage from the surviving corporation under the terms of the merger agreement. See the section entitled "*The Merger Agreement—Indemnification and Insurance*" beginning on page 105 of this proxy statement/prospectus;
- The fact that the termination payment to be paid to Dominion Energy under the circumstances specified in the merger agreement, which, while as a percentage of the equity value of the transaction is within a

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customary range for similar transactions, may discourage other parties that might otherwise have an interest in a business combination with, or an acquisition of, SCANA, or may reduce the price offered by those other parties in a competing bid. See the section entitled "*The Merger Agreement—Termination Fees*" beginning on page 100 of this proxy statement/prospectus;

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- The fact that the right afforded to Dominion Energy under the merger agreement to match acquisition proposals that the SCANA board determines in good faith are superior proposals may discourage other parties that might otherwise have an interest in a business combination with, or an acquisition of, SCANA; and

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- The risks described in the section entitled "*Risk Factors*" beginning on page 17 of this proxy statement/prospectus.

The foregoing discussion of the information and factors considered by the SCANA board is not intended to be exhaustive, but includes the material factors considered by the SCANA board. In view of the variety of factors considered in connection with its evaluation of the merger, the SCANA board did not find it practicable to, and did not, quantify or otherwise assign relative weights to the specific factors considered in reaching its determination and recommendation. In addition, individual directors may have given different weights to different factors. The SCANA board did not undertake to make any specific determination as to whether any factor, or any particular aspect of any factor, supported or did not support its ultimate determination. The SCANA board based its recommendation on the totality of the information presented.

Portions of this explanation of the reasons for the merger and other information presented in this section are forward-looking in nature and, therefore, should be read in light of the section entitled "*Cautionary Statement Regarding Forward-Looking Statements*" beginning on page 25 of this proxy statement/prospectus.

Recommendation of the SCANA Board

The SCANA board recommends that you vote "FOR" the merger proposal.

Opinions of SCANA's Financial Advisors

Opinion of Morgan Stanley & Co. LLC

Morgan Stanley was retained by SCANA to act as its financial advisor in connection with the merger and to provide financial advice and assistance and, upon SCANA's request, to render a financial opinion, in each case in connection therewith. The SCANA board selected Morgan Stanley to act as its financial advisor based on Morgan Stanley's qualifications, expertise and reputation, its knowledge of and involvement in recent transactions in SCANA's industry and its knowledge and understanding of the business and affairs of SCANA. On January 2, 2018, Morgan Stanley rendered its oral opinion, which was subsequently confirmed in writing, to the SCANA board to the effect that, as of that date, and based upon and subject to the assumptions made, procedures followed, matters considered and qualifications and limitations on the scope of review undertaken by Morgan Stanley as set forth in Morgan Stanley's written opinion, the merger consideration to be received by the holders of shares of SCANA common stock (other than the holders of the cancelled shares) pursuant to the merger agreement was fair from a financial point of view to the holders of shares of SCANA common stock.

The full text of the written opinion of Morgan Stanley delivered to the SCANA board, dated January 2, 2018, is attached as Annex B and incorporated into this proxy statement/prospectus by reference in its entirety. The opinion sets forth, among other things, the assumptions made, procedures followed, matters considered and qualifications and limitations on the scope of the review undertaken by Morgan Stanley in rendering its opinion. SCANA shareholders are urged to, and should, read the opinion carefully and in its entirety. Morgan Stanley's opinion is directed to the SCANA board and addresses only the fairness from a financial point of view of the merger consideration to be received by the holders of

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shares of SCANA common stock (other than the holders of the cancelled shares) pursuant to the merger agreement as of the date of the opinion. Morgan Stanley's opinion did not address the relative merits of the transactions contemplated by the merger agreement as compared to other business or financial strategies that might be available to SCANA, nor did it address the underlying business decision of SCANA to enter into the merger agreement or proceed with any other transaction contemplated by the merger agreement. In addition, Morgan Stanley's opinion did not in any manner address the prices at which shares of Dominion Energy common stock will trade following completion of the merger or at any time, and Morgan Stanley's opinion was not intended to, and does not, express any opinion or recommendation as to how the holders of shares of SCANA common stock should vote at the special meeting. The summary of Morgan Stanley's opinion set forth in this proxy statement/prospectus is qualified in its entirety by reference to the full text of Morgan Stanley's opinion.

For purposes of rendering its opinion, Morgan Stanley, among other things:

- reviewed certain publicly available financial statements and other business and financial information of SCANA and Dominion Energy, respectively;
- reviewed certain internal financial statements and other financial and operating data concerning SCANA and Dominion Energy, respectively;
- reviewed certain financial projections prepared by the managements of SCANA and Dominion Energy, respectively, which we refer to as the SCANA management projections and Dominion Energy management projections, respectively;
- discussed the past and current operations and financial condition and the prospects of SCANA with senior executives of SCANA;
- discussed the past and current operations and financial condition and the prospects of Dominion Energy with senior executives of Dominion Energy;
- reviewed the pro forma impact of the merger on Dominion Energy's earnings per share, cash flow, consolidated capitalization and certain financial ratios;
- reviewed the reported prices and trading activity for SCANA common stock and Dominion Energy common stock;
- compared the financial performance of SCANA and the prices and trading activity of SCANA common stock with that of certain other publicly traded companies comparable with SCANA, and their securities;
- reviewed the financial terms, to the extent publicly available, of certain comparable acquisition transactions;
- participated in certain discussions and negotiations among representatives of SCANA and Dominion Energy and their financial and legal advisors;
- reviewed the merger agreement and certain related documents; and
- performed such other analyses and considered such other factors as Morgan Stanley deemed appropriate.

In arriving at its opinion, Morgan Stanley assumed and relied upon, without independent verification, the accuracy and completeness of the information that was publicly available or supplied or otherwise made available to Morgan Stanley by SCANA and Dominion Energy, and formed a substantial basis for Morgan Stanley's opinion. With respect to the SCANA management projections and the Dominion Energy management projections, Morgan Stanley assumed that they had been reasonably prepared on bases reflecting the best currently available estimates and judgments of the respective managements of SCANA and Dominion Energy of the future financial performance of SCANA and Dominion Energy. In addition, Morgan Stanley assumed that the

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merger will be completed in accordance with the terms set forth in the merger agreement without any waiver, amendment or delay of any terms or conditions, including, among other things, that the merger will be treated as a tax-free reorganization, pursuant to the Code. Morgan Stanley relied upon, without independent verification, the assessment by the management of SCANA of: (i) the timing and risks associated with the integration of SCANA and Dominion Energy and (ii) their ability to retain key employees of SCANA and Dominion Energy, respectively. Morgan Stanley assumed that in connection with the receipt of all the necessary governmental, regulatory or other approvals and consents required for the merger, no delays, limitations, conditions or restrictions will be imposed that would have a material adverse effect on the contemplated benefits expected to be derived in the merger (but Morgan Stanley assumed, without independent verification, the reasonableness of those delays, limitations, conditions and restrictions contained in the financial projections prepared by the managements of SCANA and Dominion Energy).

Morgan Stanley is not a legal, tax, or regulatory advisor. Morgan Stanley is a financial advisor only and has relied upon, without independent verification, the assessment of SCANA and its legal, tax, and regulatory advisors with respect to legal, tax, and regulatory matters. For purposes of its analysis Morgan Stanley did not make any assessment of the status of outstanding litigation or regulatory proceedings involving SCANA and excluded the effects of any such litigation or proceedings in its analysis, other than those effects included in the financial projections prepared by the managements of SCANA and Dominion Energy, upon which Morgan Stanley relied without independent verification. Morgan Stanley expresses no opinion with respect to the fairness of the amount or nature of the compensation to any of SCANA's officers, directors or employees, or any class of such persons, relative to the merger consideration to be received by the holders of shares of SCANA common stock (other than the holders of the cancelled shares) in the merger. Morgan Stanley did not make any independent valuation or appraisal of the assets or liabilities of SCANA or Dominion Energy, nor was Morgan Stanley furnished with any such valuations or appraisals. Morgan Stanley's opinion is necessarily based on financial, economic, market and other conditions as in effect on, and the information made available to Morgan Stanley as of January 2, 2018. Events occurring after January 2, 2018 may affect Morgan Stanley's opinion and the assumptions used in preparing it, and Morgan Stanley did not assume any obligation to update, revise or reaffirm its opinion.

In arriving at its opinion, Morgan Stanley was not authorized to solicit, and did not solicit, interest from any party with respect to the acquisition, business combination or other extraordinary transaction, involving SCANA. At the direction of the management and the SCANA board, Morgan Stanley did not negotiate with anyone other than Dominion Energy.

Summary of Morgan Stanley Financial Analyses

SCANA Financial Analysis

The following is a brief summary of the material financial analyses performed by Morgan Stanley in connection with the preparation of its opinion. The following summary is not a complete description of Morgan Stanley's opinion or the financial analyses performed and factors considered by Morgan Stanley in connection with its opinion, nor does the order of analyses described represent the relative importance or weight given to those analyses. The financial analyses summarized below include information presented in tabular format. In order to fully understand the financial analyses used by Morgan Stanley, the tables must be read together with the text of each summary. The tables alone do not constitute a complete description of the financial analyses. The analyses listed in the tables and described below must be considered as a whole; considering any portion of such analyses and of the factors, without considering all analyses and factors, could create a misleading or incomplete view of the process underlying Morgan Stanley's opinion. Furthermore, mathematical analysis, such as determining the mean, median or average, is not in itself a meaningful method of using the data referred to below. Except as otherwise noted below, all implied values per share of SCANA common stock included in Morgan Stanley's presentation to the SCANA board, as described in this section, were rounded to the nearest $0.25.
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In performing the financial analyses summarized below and arriving at its opinion, Morgan Stanley used and relied upon the financial forecasts under the 5% regulatory settlement scenario and 9.75% regulatory settlement scenario. For more information, please see the section entitled "—*Certain Forecasts Prepared by SCANA's Management*" beginning on page 78 of this proxy statement/prospectus. In addition, Morgan Stanley analyzed certain financial projections based on Wall Street research reports, which we refer to as IBES. With respect to the financial forecasts under the 3.5% regulatory settlement scenario, the terms of the 3.5% regulatory settlement scenario had been publicly proposed by SCANA on November 16, 2017 and, based on the reaction from regulators and other constituencies to such proposal, it quickly became clear that the proposal, in the view of SCANA's management and the SCANA board, was not an acceptable solution to the outstanding rate and regulatory issues relating to the abandoned NND project. Accordingly, SCANA directed Morgan Stanley not to use and rely upon the financial forecasts under the 3.5% regulatory settlement scenario for purposes of Morgan Stanley's financial analyses and opinion and SCANA provided such financial forecasts to Morgan Stanley for informational reference purposes only.

Comparable Companies Analysis

Morgan Stanley performed a comparable companies analysis, which attempts to provide an implied value of a company by comparing it to similar companies that are publicly traded. Morgan Stanley reviewed and compared certain financial information, ratios and multiples relating to SCANA to corresponding financial information, ratios and multiples for publicly traded regulated electric and gas and electric-only utility companies that shared characteristics with SCANA to derive an implied valuation range for SCANA.

The companies included in the comparable companies analysis were:

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- Duke Energy Corporation

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- The Southern Company

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- American Electric Power Company, Inc.

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- Xcel Energy Inc.

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- WEC Energy Group, Inc.

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- DTE Energy Group, Inc.

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- Ameren Corporation

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- CMS Energy Corporation

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- Pinnacle West Capital Corporation

The foregoing companies were chosen based on Morgan Stanley's knowledge of the industry and because such companies have businesses that may be considered similar to SCANA's. Although none of such companies are identical or directly comparable to SCANA, these companies are publicly traded companies with operations and/or other criteria, such as lines of business, markets, business risks, growth prospects, maturity of business and size and scale of business, that, for purposes of its analysis, Morgan Stanley considered similar to those of SCANA. The foregoing summary and underlying financial analyses involved complex considerations and judgments concerning differences in financial and operating characteristics and other factors that could affect the values of the companies to which SCANA was compared. In evaluating comparable companies, Morgan Stanley made judgments and assumptions with regard to industry performance, general business, economic, market and financial conditions and other matters, which are beyond the control of SCANA, including, among other things, the impact of regulatory changes, industry growth and the absence of any adverse material change in the financial condition and prospects of SCANA or the industry or in the financial markets in general.

In performing this analysis, Morgan Stanley used the financial forecasts under the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario and IBES to compare the financial information and

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multiples of market value of the companies included in the comparable companies analysis to the following metrics of SCANA:

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- stock price to 2019 estimated earnings per share, which we refer to as EPS (based on the financial forecasts under the 5% regulatory settlement scenario);

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- stock price to 2019 estimated EPS (based on the financial forecasts under the 9.75% regulatory settlement scenario); and

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- stock price to 2019 estimated EPS (based on IBES).

Morgan Stanley did not compare SCANA's stock price to its 2018 estimated EPS because of significant write-downs expected to be made by SCANA in 2018 that would cause SCANA's earnings in 2018 to be unrepresentative. In addition, Morgan Stanley applied a discount of 1.5 multiple points to the multiples of stock price to estimated 2019 EPS for the comparable companies referred to above to reflect the long-term average (based on the past 10 years) next-twelve-month multiple discount at which SCANA common stock has traded as compared to the trading prices of the stock of such comparable companies (based on historical trading prices as a multiple of estimated next-twelve-month EPS) and the expected low rate of growth of dividends per share reflected in the SCANA management projections relative to peers. The range of multiples of stock price to estimated EPS for 2019 for the companies included in the comparable companies analysis based on a compilation of earnings estimates by selected equity research analysts (after giving effect to the 1.5 multiple point discount described above) is 14.0x to 18.0x.

Applying this range of multiples, Morgan Stanley derived a range of approximate implied equity values per share of SCANA common stock as follows:

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Metric	Implied Value Per Share of SCANA Common Stock
Stock price to 2019 estimated EPS (based on the financial forecasts under the 5% regulatory settlement scenario)	$47.00 - $60.50
Stock price to 2019 estimated EPS (based on the financial forecasts under the 9.75% regulatory settlement scenario)	$41.00 - $52.50
Stock price to 2019 estimated EPS (based on IBES)	$41.50 - $53.25

These implied value ranges were compared to the value of the merger consideration of $54.23 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $81.06, which was the closing price of Dominion Energy common stock as of December 29, 2017) and to the value of the merger consideration of $55.39 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $82.80, which was the 30-day intraday volume weighted average price of Dominion Energy common stock as of December 29, 2017, as reported by Bloomberg).

Discounted Cash Flow Analysis

Morgan Stanley performed a discounted cash flow analysis of SCANA, which is designed to provide an implied value of a company by calculating the present value of the estimated future unlevered cash flows and terminal year value based upon a price-to-earnings multiple applied to net income in the terminal year. Morgan Stanley calculated a range of implied equity values per share for SCANA common stock based on estimates of future cash flows for calendar years 2018 through 2022 and the terminal year (assuming, at the direction of SCANA's management, that, with respect to the financial forecasts under the 5% regulatory settlement scenario, terminal year net income grew at 2.6%, the compound annual growth rate from 2018 through 2022 for SCANA's

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net income in this scenario and, with respect to the financial forecasts under the 9.75% regulatory settlement scenario, terminal year net income grew at 1.0%, the compound annual growth rate from 2018 through 2022 for SCANA's net income in this scenario).

Morgan Stanley used estimates from the financial forecasts under the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario for purposes of the discounted cash flow analysis, as more fully described below. In performing a discounted cash flow analysis of SCANA using estimates from the financial forecasts under the 5% regulatory settlement scenario and 9.75% regulatory settlement scenario, Morgan Stanley first calculated the estimated unlevered free cash flows of SCANA and then calculated a terminal value for SCANA common stock by applying a 13.5x to 15.0x range of price-to-earnings multiples to SCANA's terminal year estimated net income per share. This terminal year price-to-earnings multiple range was derived from the ten-year average (for the ten-year period ending December 29, 2017) of stock price to the estimated next-twelve-month EPS multiples for the companies in the comparable companies analysis, and then applying the 1.5 multiple point discount, as described above with respect to the comparable companies analysis, to reflect the long-term average multiple discount at which SCANA's stock price to EPS traded as compared to the price to earnings multiples of the comparable companies. In view of the expected low rate of growth of dividends per share reflected in the SCANA management projections relative to peers, Morgan Stanley, based on its professional judgment and experience, did not consider it appropriate to assume that SCANA's stock would cease to trade at this 1.5 multiple point discount.

Unlevered free cash flows were calculated by tax-effecting earnings before interest and taxes and adding back the aggregate of depreciation and amortization, deferred taxes and other cash flow adjustments provided by management, including the change in working capital, less the sum of capital expenditures. The free cash flows and range of terminal values were then discounted to present value as of December 31, 2017 using discount rates ranging from 5.2% to 6.1%, which were chosen by Morgan Stanley based upon prevailing interest rates and Morgan Stanley's judgment of the estimated range of SCANA's weighted average cost of capital. This analysis indicated the following implied range of values per share of SCANA common stock:

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Metric	Implied Value Per Share of SCANA Common Stock
5% regulatory settlement scenario	$53.50 - $62.25
9.75% regulatory settlement scenario	$46.75 - $54.75

These implied value ranges were compared to the value of the merger consideration of $54.23 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $81.06, which was the closing price of Dominion Energy common stock as of December 29, 2017) and to the value of the merger consideration of $55.39 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $82.80, which was the 30-day intraday volume weighted average price of Dominion Energy common stock as of December 29, 2017, as reported by Bloomberg).

Future Stock Price Analysis

Using estimates from the financial forecasts under the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario, Morgan Stanley performed an illustrative analysis of SCANA's potential future stock price as compared to the merger consideration. This analysis compared (i) SCANA's potential future stock price for each of the years 2018 and 2019 based on SCANA's standalone projected next-twelve month EPS using an illustrative price-to-EPS multiple range derived from historical trading analyses described below and based on Morgan Stanley's professional judgment and experience to (ii) the value of the merger consideration of $54.23 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA

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common stock and a Dominion Energy common stock per share price of $81.06, which was the closing price of Dominion Energy common stock as of December 29, 2017) and the value of the merger consideration of $55.39 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $82.80, which was the 30-day intraday volume weighted average price of Dominion Energy common stock as of December 29, 2017, as reported by Bloomberg).

The illustrative price to EPS multiple range selected by Morgan Stanley in this analysis was derived from the following metrics based on the closing price of SCANA common stock as of December 29, 2017:

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- multiple to 2018 estimated EPS (13.7x), as well as a 1.5 multiple point premium and discount to such multiple (15.2x to 12.2x);

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- average next twelve month multiple of EPS for the past five years (15.1x); and

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- average next twelve month multiple of EPS for the past 10 years (14.0x).

This analysis indicated that the potential future value per share of SCANA common stock in all of the ranges of potential future values calculated using each of the financial forecasts under the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario described above would be lower than the value of the merger consideration on a per-share basis as of December 29, 2017. Specifically, across the range of multiples analyzed, this analysis indicated the following high and low range of implied values per share of SCANA common stock:

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Metric	Implied Value Per Share of SCANA Common Stock*			
	2018		2019	
	Low	High	Low	High
5% regulatory settlement scenario	$40.86	$50.93	$43.01	$53.61
9.75% regulatory settlement scenario	$35.56	$44.32	$37.61	$46.87

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* These amounts were not rounded to the nearest $0.25 in the presentation to the SCANA board.

Morgan Stanley also presented the median potential future value per share of SCANA common stock based on the ranges calculated in the analysis described above and discounted the median potential future values per share of SCANA common stock to present value using an 8.1% discount rate, which is the midpoint of SCANA's cost of equity, selected by Morgan Stanley based on the application of its professional judgment and experience, inclusive of projected dividends per share over the applicable time period discounted to present value using the same discount rate. This analysis indicated the following implied discounted median values per share of SCANA common stock:

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Metric	Implied Value Per Share of SCANA Common Stock*	
	Discounted Median Value	
	2018	2019
5% regulatory settlement scenario	$ 44.72	$ 45.68
9.75% regulatory settlement scenario	$ 39.21	$ 40.07

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* These amounts were not rounded to the nearest $0.25 in the presentation to the SCANA board.

Reference Data

In addition to conducting the analyses described above, Morgan Stanley reviewed the following data, which was used for reference purposes only and not as a component of its fairness analysis.

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Reference Discounted Cash Flow Analyses

For reference only and not as a component of its fairness analysis, Morgan Stanley performed additional discounted cash flow analyses of SCANA using the financial forecasts under the 3.5% regulatory settlement scenario and the 5% regulatory settlement scenario but, in each case, without applying the 1.5 multiple point discount mentioned above. Morgan Stanley calculated a range of implied equity values per share for SCANA common stock based on estimates of future cash flows for calendar years 2018 through 2022 and the terminal year (assuming at the direction of SCANA's management, that, with respect to the 3.5 % Rate Reduction Scenario, terminal year net income grew at 3.1%, the compound annual growth rate from 2018 through 2022 for SCANA's net income in this scenario and, with respect to the financial forecasts under the 5% regulatory settlement scenario, terminal year net income grew at 2.6%, the compound annual growth rate from 2018 to 2022 for SCANA's net income in this scenario).

In performing a discounted cash flow analysis of SCANA using estimates from the financial forecasts under the 3.5% regulatory settlement scenario and the 5% regulatory settlement scenario, Morgan Stanley first calculated the estimated unlevered free cash flows of SCANA and then calculated a terminal value for SCANA common stock by applying a 15.0x to 16.5x range of price to earnings multiples to SCANA's terminal year estimated net income. Although, as discussed above, Morgan Stanley, based on its professional judgment and experience, determined that application of the 1.5 multiple point discount was appropriate, it presented a discounted cash flow analysis using the financial forecasts under the 5% regulatory settlement scenario without applying such discount in order to illustrate for the SCANA board the potential impact on the implied range of values presented to the SCANA board if this historic multiple discount were considered not to be applicable in these scenarios. With respect to the discounted cash flow analysis using the financial forecasts under the 3.5% regulatory settlement scenario, Morgan Stanley did not apply the 1.5 multiple point discount because it concluded, based on its professional judgment and experience, that if the results projected by such scenario were achieved (despite the views of SCANA's management and the SCANA board that the 3.5% regulatory settlement scenario was unlikely to be achieved, as noted above), it would be reasonable to expect that SCANA common stock could trade at a multiple more consistent with the trading multiples of comparable companies. The terminal year price-to-earnings multiple range was derived from the ten-year average (for the ten-year period ending December 29, 2017) of stock price to the estimated next-twelve-month EPS multiples for the companies in the comparable companies analysis.

Unlevered free cash flows were calculated by tax-effecting earnings before interest and taxes and adding back the aggregate of depreciation and amortization, deferred taxes and other cash flow adjustments provided by management including the change in working capital less the sum of capital expenditures. The free cash flows and range of terminal values were then discounted to present value as of December 31, 2017 using discount rates ranging from 5.2% to 6.1%, which were chosen by Morgan Stanley based upon prevailing interest rates and Morgan Stanley's judgment of the estimated range of SCANA's weighted average cost of capital. This analysis indicated the following implied range of values per share of SCANA common stock:

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Metric	Implied Value Per Share of SCANA Common Stock
3.5% regulatory settlement scenario	$64.50 - $73.75
5% regulatory settlement scenario	$58.25 - $67.25

These implied value ranges were compared to the value of the merger consideration of $54.23 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $81.06, which was the closing price of Dominion Energy common stock as of December 29, 2017) and to the value of the merger consideration of $55.39 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $82.80, which was the 30-day intraday volume weighted average price of Dominion Energy common stock as of December 29, 2017, as reported by Bloomberg).

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Precedent Transactions Analysis

For reference only and not as a component of its fairness analysis, Morgan Stanley performed a precedent transactions analysis, which is designed to imply a value of a company based on publicly available financial information of selected transactions that share some characteristics with the merger.

Precedent Transaction Premiums. For reference only and not as a component of its fairness analysis, Morgan Stanley reviewed the premiums paid by acquirors in selected transactions in which regulated electric and gas and electric-only utilities were the target between January 1, 2014 and December 29, 2017, which was the last trading day prior to the date Morgan Stanley rendered its opinion, and that Morgan Stanley judged to be similar in certain respects to the merger or aspects thereof based on Morgan Stanley's professional judgment and experience.

For each transaction included in this analysis, Morgan Stanley noted the implied premium to the target share price one day prior to announcement, except where the share price had been affected by pre-announcement events, in which case the unaffected target share price was used. The following is a list of the transactions reviewed:

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Date Announced	Acquiror	Target
April 30, 2014	Exelon Corporation	Pepco Holdings, Inc.
June 23, 2014	Wisconsin Energy Corporation	Integrys Energy Group, Inc.
October 20, 2014	Macquarie (consortium)	Cleco Corp.
February 26, 2015	Iberdrola, S.A.	UIL Holdings Corporation
September 4, 2015	Emera Incorporated	TECO Energy, Inc.
February 9, 2016	Fortis Inc.	ITC Holdings Corp.
February 9, 2016	Algonquin Power & Utilities Corp.	The Empire District Electric Company
July 10, 2017	Great Plains Energy Incorporated	Westar Energy, Inc.
July 19, 2017	Hydro One Ltd.	Avista Corp.

Based on the foregoing results and Morgan Stanley's professional judgment and experience, Morgan Stanley applied the range of premiums of 14.7% to 50.1% for the precedent transactions to the closing price of the shares of SCANA common stock of $39.78 as of December 29, 2017 to derive a range of implied equity values per share. The results of the analysis were as indicated in the following table:

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Precedent Transactions Premiums Range	Implied Value Per Share of SCANA Common Stock
14.7% - 50.1%	$45.75 - $59.75

This implied value range was compared to the value of the merger consideration of $54.23 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $81.06, which was the closing price of Dominion Energy common stock as of December 29, 2017) and as compared to the value of the merger consideration of $55.39 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of $82.80, which was the 30-day intraday volume weighted average price of Dominion Energy common stock as of December 29, 2017, as reported by Bloomberg).

Precedent Transaction Multiples. For reference only and not as a component of its fairness analysis, Morgan Stanley observed the range of stock prices to estimated one-year-forward EPS multiples for each of the selected precedent transactions as 20.1x to 27.2x. Morgan Stanley applied these multiples to SCANA's estimated 2019

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EPS based on the financial forecasts under the 5% regulatory settlement scenario and 9.75% regulatory settlement scenario. Morgan Stanley then calculated implied equity value per share of SCANA common stock:

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Metric	Stock Price / 2019 Estimated EPS Multiple Range	Implied Present Value Per Share of SCANA Common Stock
5% regulatory settlement scenario	20.1x to 27.2x	\$62.50 - \$84.50
9.75% regulatory settlement scenario	20.1x to 27.2x	\$54.50 - \$73.50

These implied value ranges were compared to the value of the merger consideration of \$54.23 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of \$81.06, which was the closing price of Dominion Energy common stock as of December 29, 2017) and as compared to the value of the merger consideration of \$55.39 (based on the merger consideration of 0.6690 of a share of Dominion Energy common stock per share of SCANA common stock and a Dominion Energy common stock per share price of \$82.80, which was the 30-day intraday volume weighted average price of Dominion Energy common stock as of December 29, 2017, as reported by Bloomberg).

No company or transaction utilized in the precedent transactions analysis is identical to SCANA or the merger, respectively. In evaluating the precedent transactions, Morgan Stanley made judgments and assumptions with regard to industry performance, general business, market and financial conditions and other matters, which are beyond SCANA's control, including, among other things, the impact of competition on SCANA's business or the industry generally, regulatory changes, industry growth and the absence of any adverse material change in SCANA's financial condition or the industry or in the financial markets in general, which could affect the aggregate value, equity value and premium paid of the transactions to which they are being compared.

Equity Research Analysts' Price Targets. For reference only and not as a component of its fairness analysis, Morgan Stanley reviewed and analyzed the analyst price targets for SCANA common stock, of \$38.50 to \$60.00 as of December 29, 2017, which was the last trading day prior to the date Morgan Stanley rendered its opinion. Morgan Stanley then discounted the range of analyst price targets for SCANA common stock to present value using a 8.2% discount rate, which is the midpoint of SCANA's cost of equity, selected by Morgan Stanley based on the application of its professional judgment and experience, which produced an implied equity value per share range of SCANA common stock of \$35.50 to \$55.50. The public market trading price targets published by equity research analysts do not necessarily reflect current market trading prices for SCANA common stock, and these estimates are subject to uncertainties.

Historical Trading Range. For reference only and not as a component of its fairness analysis, Morgan Stanley reviewed the historical trading range of shares of SCANA common stock for the last 6 months and the last 3 months, in each case ending on December 29, 2017, and observed a range of \$37.50 to \$69.75, for the last 6 months, and a range of \$37.50 to \$56.25, for the last 3 months.

Dominion Energy Common Stock

Morgan Stanley performed only limited financial analyses related to the value of Dominion Energy common stock, for reference only and not as a component of its fairness analysis. Morgan Stanley observed the trading performance of Dominion Energy common stock for the two-year period ended December 29, 2017 as well as the commentary from selected equity research analysts with respect to Dominion Energy common stock and the observed trading liquidity of Dominion Energy common stock as compared to the number of shares of Dominion Energy common stock to be issued in the merger. As noted above, Morgan Stanley also reviewed, for reference only and not as a component of its fairness analysis, the pro forma impact of the merger on Dominion Energy's earnings per share, cash flow, consolidated capitalization and certain financial ratios. After discussion of these factors with the SCANA board, Morgan Stanley was not requested to and did not perform additional financial analyses to assess the value of Dominion Energy common stock.

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General

In connection with the review of the merger by the SCANA board, Morgan Stanley performed a variety of financial and comparative analyses for purposes of rendering its opinion. The preparation of a financial opinion is a complex process and is not necessarily susceptible to a partial analysis or summary description. In arriving at its opinion, Morgan Stanley considered the results of all of its analyses as a whole and did not attribute any particular weight to any analysis or factor it considered. Morgan Stanley believes that selecting any portion of its analyses, without considering all analyses as a whole, would create an incomplete view of the process underlying its analyses and opinion. In addition, Morgan Stanley may have given various analyses and factors more or less weight than other analyses and factors, and may have deemed various assumptions more or less probable than other assumptions. As a result, the ranges of valuations resulting from any particular analysis described above should not be taken to be Morgan Stanley's view of the actual value of SCANA or Dominion Energy.

In performing its analyses, Morgan Stanley made judgments and assumptions with regard to industry performance, general business, regulatory, economic, market and financial conditions and other matters, which are beyond the control of SCANA and Dominion Energy. These include, among other things, industry growth, and the absence of any adverse material change in the financial condition and prospects of SCANA, Dominion Energy and the industry, and in the financial markets in general. Any estimates contained in Morgan Stanley's analyses are not necessarily indicative of future results or actual values, which may be significantly more or less favorable than those suggested by such estimates.

Morgan Stanley conducted the analyses described above solely as part of its analysis of the fairness, from a financial point of view, of the merger consideration pursuant to the merger agreement to the SCANA shareholders (other than the holders of the cancelled shares), and in connection with the delivery of its opinion, dated January 2, 2018, to the SCANA board. Morgan Stanley's opinion did not address any other aspect of the merger or related transactions. The merger consideration pursuant to the merger agreement was determined through arm's-length negotiations between SCANA and Dominion Energy and the merger agreement was adopted by the SCANA board. Morgan Stanley acted as financial advisor to the SCANA board during these negotiations but did not, however, recommend any specific exchange ratio for purposes of determining the merger consideration to SCANA or the SCANA board, nor opine that any specific exchange ratio constituted the only appropriate exchange ratio for the merger.

Morgan Stanley's opinion and its presentation to the SCANA board was one of many factors taken into consideration by the SCANA board in deciding to adopt the merger agreement and approve the transactions contemplated thereby and to recommend the approval of the merger agreement by the SCANA shareholders. Consequently, the analyses as described above should not be viewed as determinative of the opinion of the SCANA board with respect to the merger consideration pursuant to the merger agreement or of whether the SCANA board would have been willing to agree to a different merger consideration. Morgan Stanley's opinion was approved by a committee of Morgan Stanley investment banking and other professionals in accordance with its customary practice.

SCANA retained Morgan Stanley based on Morgan Stanley's qualifications, experience and expertise and its familiarity with SCANA. Morgan Stanley is a global financial services firm engaged in the securities, investment management and individual wealth management businesses. Its securities business is engaged in securities underwriting, trading and brokerage activities, foreign exchange, commodities and derivatives trading, and prime brokerage, as well as providing investment banking, financing and financial advisory services. Morgan Stanley, its affiliates, directors and officers may at any time invest on a principal basis or manage funds that invest, hold long or short positions, finance positions, and may trade or otherwise structure and effect transactions, for their own account or the accounts of its customers, in debt or equity securities or loans of SCANA, Dominion Energy or any other company, or any currency or commodity, that may be involved in the merger, or any related derivative instrument.
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Under the terms of its engagement letter dated October 18, 2017, Morgan Stanley provided SCANA financial advisory services and a financial opinion, described in this section and attached to this proxy statement/prospectus as Annex B, in connection with the merger, and SCANA has agreed to pay Morgan Stanley a fee of approximately $27 million for its financial advisory services, $5 million of which was paid upon delivery of Morgan Stanley's opinion, 25% of which is contingent upon SCANA shareholder approval of the merger proposal and the remainder of which is contingent upon closing of the merger. In addition, SCANA may, in its sole discretion, pay Morgan Stanley an incremental incentive fee to be paid upon closing of the merger. SCANA has also agreed to reimburse Morgan Stanley for its reasonable out-of-pocket expenses incurred from time to time in connection with this engagement. In addition, SCANA has agreed to indemnify Morgan Stanley and its affiliates, its and their respective officers, directors, employees and agents and each other person, if any, controlling Morgan Stanley or any of its affiliates, against any losses, claims, damages or liabilities, relating to, arising out of or in connection with Morgan Stanley's engagement and to reimburse certain expenses relating to such indemnity.

In the two (2) years prior to the date of its opinion, Morgan Stanley has provided financial advisory and financing services for SCANA and has received fees in connection with such services in the range of $0 to $1 million. In addition, in the two (2) years prior to the date of its opinion, Morgan Stanley has provided financing services to Dominion Energy and has received fees in connection with such services in the range of $10 million to $11 million. Morgan Stanley may also seek to provide financial advisory and financing services to SCANA, Dominion Energy and their respective affiliates in the future and would expect to receive fees for the rendering of these services.

Opinion of RBC Capital Markets, LLC

SCANA engaged RBC Capital Markets as a financial advisor in connection with the merger. As part of this engagement, the SCANA board requested that RBC Capital Markets evaluate the fairness, from a financial point of view, of the merger consideration to be received by holders of SCANA common stock pursuant to the merger agreement. At a January 2, 2018 meeting of the SCANA board held to evaluate the merger, RBC Capital Markets rendered an oral opinion, confirmed by delivery of a written opinion dated January 2, 2018, to the SCANA board to the effect that, as of that date and based on and subject to the procedures followed, assumptions made, factors considered and qualifications and limitations described in the opinion, the merger consideration to be received by holders of SCANA common stock pursuant to the merger agreement was fair, from a financial point of view, to such holders. The full text of RBC Capital Markets' written opinion, dated January 2, 2018, which is attached as Annex C to this proxy statement/prospectus and incorporated in this document by reference, sets forth, among other things, the procedures followed, assumptions made, factors considered and qualifications and limitations on the review undertaken by RBC Capital Markets in connection with its opinion, as more fully described in this section. The following summary of RBC Capital Markets' opinion is qualified in its entirety by reference to the full text of the opinion. **RBC Capital Markets delivered its opinion to the SCANA board for the benefit, information and assistance of the SCANA board (in its capacity as such) in connection with of its evaluation of the merger. RBC Capital Markets' opinion addressed only the fairness, from a financial point of view and as of the date of such opinion, of the merger consideration (to the extent expressly specified in such opinion) and did not address any other aspect of the merger. RBC Capital Markets' opinion also did not address the underlying business decision of SCANA to engage in the merger or the relative merits of the merger compared to any alternative business strategy or transaction that might be available to SCANA or in which SCANA might engage. RBC Capital Markets does not express any opinion and does not make any recommendation to any shareholder as to how such shareholder should vote or act with respect to the merger or any proposal to be voted upon in connection with the merger or otherwise.**

For purposes of rendering its opinion, RBC Capital Markets undertook such review, inquiries and analyses as it deemed necessary or appropriate under the circumstances and, among other things:

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- reviewed the financial terms of a draft, dated January 2, 2018, of the merger agreement;

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- reviewed certain publicly available financial and other information, and certain historical operating data, relating to SCANA and Dominion Energy made available to RBC Capital Markets from published sources and internal records of SCANA and Dominion Energy, respectively;
- reviewed certain financial projections and other estimates and data (including as to certain tax attributes) relating to SCANA prepared by the management of SCANA based on alternative regulatory settlement cases, and reviewed certain financial projections and other estimates and data relating to Dominion Energy prepared by the management of Dominion Energy, which projections and other estimates and data RBC Capital Markets was directed by SCANA to utilize for purposes of its analyses and opinion;
- conducted discussions with members of the senior managements of SCANA and Dominion Energy with respect to the respective businesses, prospects and financial outlook of SCANA and Dominion Energy;
- reviewed the reported prices and trading activity for shares of SCANA common stock and Dominion Energy common stock;
- compared certain financial metrics of SCANA and Dominion Energy with those of selected publicly traded companies in lines of businesses that RBC Capital Markets considered generally relevant in evaluating SCANA and Dominion Energy, respectively;
- reviewed certain potential pro forma financial effects of the merger on Dominion Energy; and
- considered other information and performed other studies and analyses as RBC Capital Markets deemed appropriate.

In rendering its opinion, RBC Capital Markets assumed and relied upon the accuracy and completeness of all information that was reviewed by RBC Capital Markets, including all financial, legal, tax, accounting, operating and other information provided to or discussed with RBC Capital Markets by or on behalf of SCANA or Dominion Energy (including, without limitation, financial statements and related notes), and upon the assurances of the respective managements and other representatives of SCANA and Dominion Energy that they were not aware of any relevant information that was omitted or that remained undisclosed to RBC Capital Markets. RBC Capital Markets did not assume responsibility for independently verifying and it did not independently verify such information. RBC Capital Markets also assumed that the financial projections and other estimates and data (including potential tax attributes relating to SCANA) that RBC Capital Markets was directed to utilize in its analyses were reasonably prepared on bases reflecting the best currently available estimates and good faith judgments of the respective managements of SCANA and Dominion Energy, as the case may be, as to the future financial performance of, and were a reasonable basis upon which to evaluate, SCANA under the alternative regulatory settlement cases reflected therein, Dominion Energy, the potential pro forma effects of the merger and the other matters covered thereby. RBC Capital Markets expressed no opinion as to any such financial projections and other estimates and data or the assumptions upon which they were based. RBC Capital Markets relied upon the assessments of the managements of SCANA and Dominion Energy as to, among other things, (i) the potential impact on SCANA and Dominion Energy of market, competitive, seasonal, and other trends and developments in and prospects for, and governmental, regulatory and legislative matters relating to or otherwise affecting, the utility, power and energy industries and the sectors of such industries and geographic regions in which SCANA and Dominion Energy operate (including, without limitation, with respect to future commodity prices and availability, which are subject to significant volatility, existing, planned and/or abandoned infrastructure and other capital projects, including the construction and abandonment of the NND project, and pending and future rate cases, cost recovery and other regulatory proceedings and determinations) and assumptions of the managements of SCANA and Dominion Energy, respectively, as to such matters which, if different than as provided to RBC Capital Markets, could have a meaningful impact on RBC Capital Markets' analyses or opinion, (ii) existing and future relationships, agreements and arrangements with, and the ability to attract, retain and/or replace, key employees, customers, suppliers, contractors and subcontractors and other commercial relationships of SCANA and Dominion Energy, and (iii) the ability to integrate the operations of

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SCANA and Dominion Energy. RBC Capital Markets assumed that there would be no developments with respect to any of the foregoing that would have an adverse effect on SCANA, Dominion Energy or the merger or that otherwise would be meaningful in any respect to its analyses or opinion.

In connection with its opinion, RBC Capital Markets did not assume any responsibility to perform, and it did not perform, an independent valuation or appraisal of any of the assets or liabilities (contingent, off-balance sheet, accrued, derivative or otherwise) of or relating to SCANA, Dominion Energy or any other entity and RBC Capital Markets was not furnished with any such valuations or appraisals. RBC Capital Markets expressed no view or opinion as to the potential impact on SCANA, Dominion Energy or any other entity of any pending or potential litigation, claims or governmental, regulatory or other proceedings or investigations. RBC Capital Markets did not assume any obligation to conduct, and it did not conduct, any physical inspection of the properties or facilities of SCANA, Dominion Energy or any other entity. RBC Capital Markets did not evaluate the solvency or fair value of SCANA, Dominion Energy or any other entity under any state, federal or other laws relating to bankruptcy, insolvency or similar matters. RBC Capital Markets assumed that the merger would be completed in accordance with the terms of the merger agreement and in compliance with all applicable laws, documents and other requirements, without waiver, modification or amendment of any material term, condition or agreement, and that, in the course of obtaining the necessary governmental, regulatory or third-party approvals, consents, releases, waivers and agreements for the merger, no delay, limitation, restriction or condition would be imposed or occur, including any divestiture or other requirements, that would have an adverse effect on SCANA, Dominion Energy or the merger or that otherwise would be meaningful in any respect to its analyses or opinion. RBC Capital Markets also assumed that the merger would qualify as a reorganization within the meaning of Section 368(a) of the Code for U.S. federal income tax purposes. In addition, RBC Capital Markets assumed that the final executed merger agreement would not differ, in any respect meaningful to its analyses or opinion, from the draft that RBC Capital Markets reviewed.

RBC Capital Markets' opinion spoke only as of the date of the opinion, was based on conditions as they existed and information supplied or reviewed as of the date of the opinion, and was without regard to any market, economic, financial, legal, regulatory or other circumstances or event of any kind or nature which may exist or occur after such date. RBC Capital Markets did not undertake and has no obligation to reaffirm, revise or update its opinion or otherwise comment upon events occurring after the date of its opinion with respect to its opinion. RBC Capital Markets did not express any opinion as to the actual value of Dominion Energy common stock when issued in connection with the merger or the price or range of prices at which SCANA common stock, Dominion Energy common stock or any other securities of SCANA or Dominion Energy may trade or otherwise be transferable at any time, including following announcement or completion of the merger. As the SCANA board was aware, the credit, financial and stock markets, and the industries in which SCANA and Dominion Energy operate, have experienced and continue to experience volatility and RBC Capital Markets expressed no opinion or view as to any potential effects of such volatility on SCANA or Dominion Energy (or their respective businesses) or the merger.

RBC Capital Markets' opinion addressed the fairness, from a financial point of view and as of the date of the opinion, of the merger consideration (to the extent expressly specified in the opinion), without regard to individual circumstances of specific holders that may distinguish such holders or the securities of SCANA held by such holders. RBC Capital Markets' opinion did not in any way address any other terms, conditions, implications or other aspects of the merger or the merger agreement, including, without limitation, the form or structure of the merger, or any other agreement, arrangement or understanding to be entered into in connection with or contemplated by the merger or otherwise. RBC Capital Markets did not express any opinion or view with respect to, and RBC Capital Markets relied upon the assessments of SCANA and SCANA's representatives regarding, legal, regulatory, tax, accounting and similar matters (including changes resulting from, and the impact of, the recent U.S. tax reform), as to which RBC Capital Markets understood that SCANA obtained such advice as SCANA deemed necessary from qualified professionals. Further, in rendering its opinion, RBC Capital Markets did not express any view on, and its opinion did not address, the fairness of the amount or nature of the compensation (if any) or other consideration to any officers, directors or employees of any party, or class of such

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persons, relative to the merger consideration or otherwise. In connection with its engagement, RBC Capital Markets was not requested to, and it did not, undertake a third-party solicitation process on SCANA's behalf with respect to the acquisition of all or a part of SCANA. The issuance of RBC Capital Markets' opinion was approved by RBC Capital Markets' fairness opinion committee.

In preparing its opinion to the SCANA board, RBC Capital Markets performed various financial and comparative analyses, including those described below. The summary below of RBC Capital Markets' material financial analyses provided to the SCANA board in connection with RBC Capital Markets' opinion is not a comprehensive description of all analyses undertaken or factors considered by RBC Capital Markets in connection with its opinion. The preparation of a financial opinion is a complex analytical process involving various determinations as to the most appropriate and relevant methods of financial analysis and the application of those methods to the particular circumstances and, therefore, a financial opinion is not readily susceptible to partial analysis or summary description.

In arriving at its opinion, RBC Capital Markets employed several analytical methodologies and no one method of analysis should be regarded as critical to the overall conclusion reached by RBC Capital Markets. Each analytical technique has inherent strengths and weaknesses, and the nature of the available information may further affect the value of particular techniques. The overall conclusion reached by RBC Capital Markets was based on all analyses and factors presented, taken as a whole, and also on application of RBC Capital Markets' experience and judgment. Such conclusion may have involved significant elements of subjective judgment and qualitative analysis and no opinion was given as to the value or merit standing alone of any one or more portions of such analyses or factors.

In performing its analyses, RBC Capital Markets considered industry performance, general business and economic conditions and other matters, many of which are beyond the control of SCANA and Dominion Energy. The estimates of the future performance of SCANA and Dominion Energy in or underlying RBC Capital Markets' analyses are not necessarily indicative of actual values or actual future results, which may be significantly more or less favorable than those estimates or those suggested by RBC Capital Markets' analyses. The analyses do not purport to be appraisals or to reflect the prices at which a company or business might actually be sold or acquired or the prices at which any securities have traded or may trade at any time in the future. Accordingly, the estimates used in, and the ranges of valuations resulting from, any particular analysis described below are inherently subject to substantial uncertainty and should not be taken as RBC Capital Markets' view of the actual value of SCANA or Dominion Energy.

The merger consideration was determined through negotiations between SCANA and Dominion Energy and the decision of SCANA to enter into the merger agreement was solely that of the SCANA board. RBC Capital Markets' opinion and analyses were only one of many factors considered by the SCANA board in its evaluation of the merger and should not be viewed as determinative of the views of the SCANA board, SCANA's management or any other party with respect to the merger or the merger consideration to be received by holders of SCANA common stock pursuant to the merger agreement.

Financial Analyses

The summary of the financial analyses described below under this heading "—*Financial Analyses*" is a summary of the material financial analyses provided by RBC Capital Markets to the SCANA board in connection with RBC Capital Markets' opinion, dated January 2, 2018. **The financial analyses summarized below include information presented in tabular format. In order to fully understand the financial analyses performed by RBC Capital Markets, the tables must be read together with the text of each summary. The tables alone do not constitute a complete description of the financial analyses. Selecting portions of RBC Capital Markets' financial analyses or factors considered or focusing on the data set forth in the tables below without considering all analyses or factors or the full narrative description of such analyses or factors, including the methodologies and assumptions underlying the analyses, could create a misleading or incomplete view**
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of RBC Capital Markets' financial analyses. In RBC Capital Markets' opinion, the term merger consideration is defined as the implied per share value payable in the merger utilizing the 0.6690 exchange ratio and, for purposes of RBC Capital Markets' financial analyses described below performed in connection with such opinion, the implied value was $54.23 per share based on the 0.6690 exchange ratio and the closing price of Dominion Energy common stock on December 29, 2017 (the last trading day prior to the date of RBC Capital Markets' opinion to the SCANA board), which implied per share amount is referred to below as the implied per share merger consideration. Financial data utilized for SCANA in the financial analyses described below, to the extent based on internal financial forecasts and estimates of SCANA's management, were based on two potential alternative regulatory settlement cases, referred to individually as the 5% regulatory settlement case and the 9.75% regulatory settlement case, respectively, and collectively as the SCANA forecasts, that SCANA directed RBC Capital Markets to use and rely upon for purposes of its analyses and opinion. Financial data utilized for Dominion Energy in the financial analyses described below, to the extent based on internal financial forecasts and estimates of management, were based on financial forecasts and other information and data relating to Dominion Energy provided to or discussed with RBC Capital Markets by the management of Dominion Energy, which we refer to as the Dominion Energy forecasts.

SCANA Financial Analyses

Selected Public Companies Analysis. RBC Capital Markets performed a selected public companies analysis in which RBC Capital Markets reviewed certain financial and stock market information of SCANA and the following nine selected companies that RBC Capital Markets considered generally relevant as publicly traded companies with predominantly regulated integrated utility operations and over $5 billion in market capitalization, which we collectively refer to as the SCANA selected companies:

- Alliant Energy Corporation
- Ameren Corporation
- American Electric Power Company, Inc.
- CMS Energy Corporation
- Duke Energy Corporation
- Pinnacle West Capital Corporation
- The Southern Company
- WEC Energy Group, Inc.
- Xcel Energy Inc.

In its selected public companies analysis of SCANA, RBC Capital Markets reviewed, among other things, closing stock prices on December 29, 2017 as a multiple of calendar year 2019 estimated earnings per share, which we refer to as EPS. Financial data of the SCANA selected companies was based on publicly available research analysts' estimates and other publicly available information. Financial data of SCANA was based on publicly available research analysts' estimates, other publicly available information and the SCANA forecasts.

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The overall low to high calendar year 2019 estimated EPS multiples observed for the SCANA selected companies were 15.4x to 19.2x (with a mean of 18.0x and a median of 18.5x). RBC Capital Markets also observed that the calendar year 2019 estimated EPS multiple for SCANA was 13.3x (based on publicly available research analysts' estimates). RBC Capital Markets then applied a selected range of calendar year 2019 estimated EPS multiples of 13.3x to 18.5x to corresponding data of SCANA based on the SCANA forecasts. This analysis indicated the following approximate implied per share equity value reference ranges for SCANA, as compared to the implied per share merger consideration:

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Approximate Implied Per Share Equity Value Reference Ranges Based on:		Implied Per Share Merger Consideration
5% Regulatory Settlement Case	9.75% Regulatory Settlement Case	
$44.55 – $62.17	$38.77 – $54.11	$54.23

No company used in these analyses is identical to SCANA. Accordingly, an evaluation of the results of these analyses is not entirely mathematical. Rather, these analyses involve complex considerations and judgments concerning differences in financial and operating characteristics and other factors that could affect the public trading or other values of the companies to which SCANA was compared.

Discounted Cash Flow Analysis. RBC Capital Markets performed a discounted a cash flow analysis of SCANA by calculating the estimated present values of the standalone unlevered, after-tax free cash flows that SCANA was forecasted to generate during the fiscal years ending December 31, 2018 through December 31, 2021 based on the SCANA forecasts. RBC Capital Markets calculated terminal values for SCANA at the end of 2021 by applying to the terminal year 2022 estimated net income of SCANA a selected range of one-year forward EPS multiples of 14.2x to 16.9x. The unlevered, after-tax free cash flows and terminal values were then discounted to present value (as of December 31, 2017) using a selected discount rate range of 5.10% to 6.10%. This analysis indicated the following approximate implied per share equity value reference ranges for SCANA, as compared to the implied per share merger consideration:

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Approximate Implied Per Share Equity Value Reference Ranges Based on:		Implied Per Share Merger Consideration
5% Regulatory Settlement Case	9.75% Regulatory Settlement Case	
$52.59 – $65.51	$47.24 – $58.89	$54.23

Dominion Energy Financial Analysis

Selected Public Companies Analysis. RBC Capital Markets performed a selected public companies analysis in which RBC Capital Markets reviewed certain financial and stock market information of Dominion Energy and the following five selected companies that RBC Capital Markets considered generally relevant as publicly traded diversified, integrated utilities with over $10 billion in market capitalization, which we collectively refer to as the Dominion Energy selected companies:

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- Avangrid, Inc.

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- CenterPoint Energy, Inc.

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- DTE Energy Company

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- NextEra Energy, Inc.

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- Sempra Energy

In its selected public companies analysis of Dominion Energy, RBC Capital Markets reviewed, among other things, closing stock prices on December 29, 2017 as a multiple of calendar years 2018 and 2019 estimated EPS. Financial data of the Dominion Energy selected companies was based on publicly available research analysts' estimates and other publicly available information. Financial data of Dominion Energy was based on publicly available information and the Dominion Energy forecasts.

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The overall low to high calendar year 2018 estimated EPS and calendar year 2019 estimated EPS multiples observed for the Dominion Energy selected companies were 19.3x to 21.5x (with a mean of 20.2x and a median of 19.8x) and 16.1x to 20.1x (with a mean of 18.5x and a median of 18.7x), respectively. RBC Capital Markets also observed that the calendar year 2018 estimated EPS and calendar year 2019 estimated EPS multiples for Dominion Energy were 20.1x and 19.0x, respectively (based on publicly available research analysts' estimates). RBC Capital Markets then applied selected ranges of calendar year 2018 estimated EPS and calendar year 2019 estimated EPS multiples of 19.3x to 21.5x and 16.1x to 20.1x, respectively, to corresponding data of Dominion Energy based on the Dominion Energy forecasts. This analysis indicated the following approximate implied per share equity value reference ranges for Dominion Energy, as compared to the per share closing price of Dominion Energy common stock on December 29, 2017:

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Approximate Implied Per Share Equity Value Reference Ranges Based on:		Dominion Energy Per Share Closing Stock Price on December 29, 2017
CY2018E EPS	CY2019E EPS	
$80.18 – $89.59	$68.49 – $85.50	$81.06

No company used in these analyses is identical to Dominion Energy. Accordingly, an evaluation of the results of these analyses is not entirely mathematical. Rather, these analyses involve complex considerations and judgments concerning differences in financial and operating characteristics and other factors that could affect the public trading or other values of the companies to which Dominion Energy was compared.

Certain Additional Information

RBC Capital Markets observed certain factors that were not considered part of RBC Capital Markets' financial analyses with respect to its opinion but were referenced for informational purposes, including, among other things, the following:

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- the historical trading performance of SCANA common stock and Dominion Energy common stock during the 52-week period ended December 29, 2017, which indicated low and high closing prices during such 52-week period of approximately $37.39 and $73.61 per share for SCANA common stock and approximately $71.68 and $84.91 per share for Dominion Energy common stock;

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- publicly available research analysts' forward stock price targets for SCANA common stock and Dominion Energy common stock, discounted to present value using discount rate ranges of 6.40% to 7.40% and 5.40% to 6.40%, respectively, which indicated target stock price ranges of approximately $36.01 to $56.13 per share for SCANA common stock and approximately $72.71 to $84.99 per share for Dominion Energy common stock.

Miscellaneous

SCANA has agreed to pay RBC Capital Markets for its services as a financial advisor an aggregate fee estimated to be approximately $14 million, of which $5 million was payable upon delivery of RBC Capital Markets' opinion, 25% is payable upon receipt of approval of the merger by SCANA shareholders and the balance is contingent upon completion of the merger. RBC Capital Markets also may be entitled to an incremental incentive fee (the amount of which has not yet been determined) payable, in SCANA's sole discretion, upon completion of the merger. SCANA also has agreed to reimburse RBC Capital Markets for expenses incurred in connection with RBC Capital Markets' services and to indemnify RBC Capital Markets and related persons against certain liabilities arising out of RBC Capital Markets' engagement.

As the SCANA board was aware, RBC Capital Markets and certain of its affiliates in the past have provided, currently are providing and in the future may provide investment banking and commercial banking services to SCANA and/or its affiliates unrelated to the merger, for which services RBC Capital Markets and its affiliates have received and expect to receive customary compensation, including, during the two-year period

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prior to the date of RBC Capital Markets' opinion, having acted or acting as a lender under certain credit facilities of SCANA. During such two-year period, RBC Capital Markets and such affiliates received aggregate fees for such commercial banking services described above of approximately $0.5 million from SCANA. As the SCANA board also was aware, RBC Capital Markets and certain of its affiliates in the past have provided, currently are providing and in the future may provide investment banking and commercial banking services to Dominion Energy and/or its affiliates, for which services RBC Capital Markets and its affiliates have received or expect to receive customary compensation, including, during the two-year period prior to the date of RBC Capital Markets' opinion, having acted or acting as (i) joint lead manager or joint book-running manager for certain debt and equity offerings of Dominion Energy and certain of its affiliates in 2016 and 2017 and (ii) joint lead arranger for, and as a lender under, certain bridge and other credit facilities of Dominion Energy and certain of its affiliates. During such two-year period, RBC Capital Markets and such affiliates received aggregate fees for such investment banking and commercial banking services of approximately $24 million from Dominion Energy and certain of its affiliates.

RBC Capital Markets, as part of its investment banking services, is regularly engaged in the valuation of businesses and their securities in connection with mergers and acquisitions, corporate restructurings, underwritings, secondary distributions of listed and unlisted securities, private placements and valuations for corporate and other purposes. In the ordinary course of business, RBC Capital Markets and/or certain of its affiliates may act as a market maker and broker in the publicly traded securities of SCANA, Dominion Energy and/or other entities involved in the merger or their respective affiliates and receive customary compensation in connection therewith, and may also actively trade securities of SCANA, Dominion Energy and/or other entities involved in the merger or their respective affiliates for RBC Capital Markets' or its affiliates' account or for the account of customers and, accordingly, RBC Capital Markets and its affiliates may hold a long or short position in such securities.

RBC Capital Markets is an internationally recognized investment banking firm which is regularly engaged in providing financial advisory services in connection with mergers and acquisitions. SCANA selected RBC Capital Markets as SCANA's financial advisor in connection with the merger on the basis of RBC Capital Markets' experience in similar transactions, reputation in the investment community and familiarity with SCANA and its business.

Directors and Management of Dominion Energy After the Merger

Upon completion of the merger, the board of directors and executive officers of Dominion Energy are expected to remain unchanged. Pursuant to the terms of the merger agreement, as soon as practical after completion of the merger, the Dominion Energy board intends to appoint a mutually agreeable current member of the SCANA board or SCANA's executive management to serve on the Dominion Energy board. For information on Dominion Energy's current directors and executive officers, please see Dominion Energy's proxy statement dated March 20, 2017. See the section entitled "*Where You Can Find More Information*" beginning on page 136 of this proxy statement/prospectus.

U.S. Federal Income Tax Consequences of the Merger

The following is a general discussion of the U.S. federal income tax consequences of the merger to "U.S. holders" (as defined below) of SCANA common stock that receive shares of Dominion Energy common stock in exchange for their shares of SCANA common stock in the merger. The following discussion is based upon the Code, the U.S. Treasury regulations promulgated thereunder and judicial and administrative authorities, rulings and decisions, all as in effect as of the date of this proxy statement/prospectus. These authorities may change, possibly with retroactive effect, and any such change could affect the accuracy of the statements and conclusions set forth in this discussion. This discussion does not address any tax consequences arising under the unearned income Medicare contribution tax pursuant to the Health Care and Education Reconciliation Act of 2010, nor does it address any tax consequences arising under the laws of any state, local or foreign jurisdiction, or under any U.S. federal laws other than those pertaining to the income tax.
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The following discussion applies only to U.S. holders of shares of SCANA common stock who hold such shares as capital assets within the meaning of Section 1221 of the Code (generally, property held for investment). Further, this discussion does not purport to consider all aspects of U.S. federal income taxation that might be relevant to U.S. holders in light of their particular circumstances and does not apply to U.S. holders subject to special treatment under the U.S. federal income tax laws (such as, for example, dealers or brokers in securities, commodities or foreign currencies, traders in securities that elect to apply a mark-to-market method of accounting, banks and certain other financial institutions, insurance companies, mutual funds, tax-exempt organizations, holders subject to the alternative minimum tax provisions of the Code, partnerships, S corporations or other pass-through entities or investors in partnerships, regulated investment companies, real estate investment trusts, controlled foreign corporations, passive foreign investment companies, former citizens or residents of the United States, U.S. expatriates, holders whose functional currency is not the U.S. dollar, holders who hold shares of SCANA common stock as part of a hedge, straddle, constructive sale or conversion transaction or other integrated investment, holders who acquired SCANA common stock pursuant to the exercise of employee stock options, through a tax qualified retirement plan or otherwise as compensation or holders who actually or constructively own more than 5% of SCANA common stock).

For purposes of this discussion, the term “U.S. holder” means a beneficial owner of SCANA common stock that is for U.S. federal income tax purposes (i) an individual citizen or resident of the United States, (ii) a corporation, or entity treated as a corporation for U.S. federal income tax purposes, organized in or under the laws of the United States or any state thereof or the District of Columbia, (iii) a trust if (a) a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust or (b) such trust has made a valid election to be treated as a U.S. person for U.S. federal income tax purposes or (iv) an estate, the income of which is includible in gross income for U.S. federal income tax purposes, regardless of its source.

If an entity or arrangement treated as a partnership for U.S. federal income tax purposes holds SCANA common stock, the tax treatment of a partner in such partnership generally will depend on the status of the partner and the activities of the partnership. Any entity treated as a partnership for U.S. federal income tax purposes that holds SCANA common stock, and any partners in such partnership, should consult their own independent tax advisors regarding the tax consequences of the merger to their specific circumstances.

Determining the actual tax consequences of the merger to you may be complex and will depend on your specific situation and on factors that are not within our control. You should consult your own independent tax advisor as to the specific tax consequences of the merger in your particular circumstances, including the applicability and effect of the alternative minimum tax and any state, local, foreign and other tax laws and of changes in those laws.

Consequences of the Merger

The parties intend for the merger to be treated as a “reorganization” within the meaning of Section 368(a) of the Code for U.S. federal income tax purposes. At the time of effectiveness of the registration statement relating to this proxy statement/prospectus, Dominion Energy and SCANA have obtained written tax opinions from Morgan, Lewis & Bockius, LLP, special tax counsel to Dominion Energy, and from Mayer Brown LLP, legal counsel to SCANA, respectively, that the merger will qualify as a “reorganization” within the meaning of Section 368(a) of the Code. In addition, Dominion Energy expects to receive an opinion from Morgan, Lewis & Bockius LLP dated the closing date of the merger, to the effect that the merger will qualify as a “reorganization” within the meaning of Section 368(a) of the Code and SCANA expects to receive an opinion from Mayer Brown LLP, dated the closing date of the merger, to the effect that the merger will qualify as a “reorganization” within the meaning of Section 368(a) of the Code. These opinions were and will be based on facts and representations contained in representation letters provided by Dominion Energy and SCANA and on customary factual assumptions. The obligations of Dominion Energy and SCANA are not, however, contingent on receipt of these opinions. None of the opinions described above will be binding on the IRS or any court. Dominion Energy and

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SCANA have not sought and will not seek any ruling from the IRS regarding any matters relating to the merger, and as a result, there can be no assurance that the IRS will not assert, or that a court would not sustain, a position contrary to any of the conclusions set forth below. In addition, if any of the representations or assumptions upon which those opinions are based are inconsistent with the actual facts, the U.S. federal income tax consequences of the merger could be adversely affected. Assuming that, in accordance with the opinions described above, the merger qualifies as a “reorganization” within the meaning of Section 368(a) of the Code, upon the exchange of SCANA common stock for Dominion Energy common stock and cash in lieu of fractional shares, the U.S. federal income tax consequences will be as follows:

Upon exchanging your SCANA common stock for Dominion Energy common stock, you generally will not recognize gain or loss, except with respect to cash received in lieu of fractional shares of Dominion Energy common stock (as discussed below). The aggregate tax basis of Dominion Energy common stock that you receive in the merger (including any fractional shares deemed received) will equal your aggregate adjusted tax basis in the shares of SCANA common stock you surrender in the merger. Your holding period for the shares of Dominion Energy common stock that you receive in the merger (including any fractional share deemed received) will include your holding period for the shares of SCANA common stock that you surrender in the merger. If you acquired different blocks of SCANA common stock at different times or at different prices, Dominion Energy common stock you receive will be allocated pro rata to each block of SCANA common stock, and the basis and holding period of each block of Dominion Energy common stock you receive will be determined on a block-for-block basis depending on the basis and holding period of the blocks of SCANA common stock exchanged for such Dominion Energy common stock.

If you receive cash in lieu of a fractional share of Dominion Energy common stock, you will be treated as having received such fractional share of Dominion Energy common stock pursuant to the merger and then as having sold such fractional share of Dominion Energy common stock for cash. As a result, you generally will recognize capital gain or loss equal to the difference between the amount of cash received for such fractional share and your basis in your fractional share of Dominion Energy common stock as set forth above. Such capital gain or loss generally will be long-term capital gain or loss if, as of the effective date of the merger, your holding period for such fractional share (as described above) exceeds one year. Long-term capital gains of individuals are generally eligible for reduced rates of taxation. The deductibility of capital losses is subject to limitations.

Accounting Treatment

Dominion Energy prepares its financial statements in accordance with GAAP. The merger will be accounted for using the acquisition method of accounting. Dominion Energy will be treated as the acquiror for accounting purposes.

No Dissenters’ Rights

In accordance with Section 33-13-102(B) of the SCBCA, SCANA shareholders will not be entitled to exercise dissenters’ rights, appraisal rights or other similar rights in connection with the merger and the other transactions contemplated by the merger agreement because the shares of SCANA common stock will be listed on the NYSE as of the record date of the special meeting.

Regulatory Approvals Required for the Merger

General

Under the terms of the merger agreement, to complete the merger, Dominion Energy and SCANA must obtain approvals or consents from, or make filings with, a number of U.S. federal and state regulatory authorities. The material regulatory approvals, consents and filings include the following:

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- approval by the SCPSC of the cost recovery plan;

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- the SCPSC shall have made a SCPSC merger determination;
- authorization from the NCUC for Dominion Energy and SCANA to enter into the proposed business combination transaction as required by North Carolina Gen. Stat. § 62-111(a);
- approval by the GPSC of the indirect change of ownership of SCANA Energy Marketing, Inc., which we refer to as SEMI, from SCANA to Dominion Energy as required by O.C.G.A. § 46-4-25;
- the expiration or early termination of certain waiting periods under the HSR Act and the related rules and regulations, which provide that certain acquisition transactions may not be completed until required information has been furnished to the Antitrust Division of the DOJ and the FTC (early termination of the HSR Act waiting period was granted on February 1, 2018);
- authorization from the FERC pursuant to Section 203 of the FPA;
- consent by the NRC to the indirect transfer of control of NRC licenses from SCANA to Dominion Energy as required by Section 184 of the Atomic Energy Act and the NRC's implementing regulations in 10 C.F.R. 50.80; and
- consent from the FCC, for the transfer of control over certain FCC licenses for private internal communications held by certain SCANA subsidiaries (completion of the merger is not conditioned on receipt of FCC approval).

Dominion Energy and SCANA have made and will make various filings and submissions for the above-mentioned authorizations and approvals and will each use their reasonable best efforts to obtain these authorizations and approvals, subject to certain conditions, including that these authorizations and approvals (other than the applicable SCPSC approvals which are subject to a different standard described in the immediately following paragraph) or any law or order relating to them do not impose or require any undertakings, obligations or remedial actions that constitute a burdensome condition (which is described in "*The Merger Agreement—Reasonable Best Efforts to Obtain Regulatory Approvals*" beginning on page 92 of this proxy statement/prospectus) Dominion Energy and SCANA currently anticipate completing the merger in 2018. Although Dominion Energy and SCANA believe that the required authorizations, approvals and consents described in further detail below to complete the merger will be received within that time frame, there can be no assurance as to the precise timing of or the ultimate ability of Dominion Energy and SCANA to obtain such authorizations, approvals or consents (or any additional authorizations, approvals or consents which may otherwise become necessary). The following is a brief summary of required federal and state regulatory filings and approvals related to the merger.

SCPSC Approval

No statute or rule expressly requires approval of the merger by the SCPSC. However, the SCPSC has in the past sought to exercise authority to review and approve business combinations similar to the merger pursuant to S.C. Code Ann. § 58-27-1300 or, without expressly asserting jurisdiction over a merger, has issued findings that the merger was in the public interest or that there was an absence of harm to South Carolina rate payers as a result of the merger. As a result, the merger agreement contains a closing condition to the effect that the SCPSC shall have made a SCPSC merger determination. If the SCPSC fails or declines to make a SCPSC merger determination, then Dominion Energy will not be obligated to complete the merger.

In addition, on December 12, 2017, SCE&G made a public commitment to the SCPSC that on or before January 12, 2018, it would submit a comprehensive plan to reduce the costs incurred by customers associated with the abandoned NND project. On January 12, 2018, Dominion Energy and SCE&G filed the SCPSC petition with the SCPSC seeking a ruling from the SCPSC approving the merger with no material changes to the terms of the merger or making a finding that the merger is in the public interest or that there is an absence of harm to South Carolina rate payers as a result of the merger. The SCPSC petition further requests the SCPSC to approve

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the cost recovery plan with no material change to the proposed terms, conditions or undertakings set forth in the cost recovery plan and no significant change to the economic value of the cost recovery plan, in each case as reasonably determined by Dominion Energy in good faith. There is no guarantee that the SCPSC will take these actions, or that it will not impose conditions on such approvals that result in a failure of a closing condition to the merger.

NCUC Approval

Approval of the business combination transaction is required under N.C.G.S. § 62-111(a) for the indirect transfer of ownership of Public Service Company of North Carolina, Inc., which we refer to as PSNC, from SCANA to Dominion Energy. The standard for approval is that the merger is justified by the public convenience and necessity. In a 2016 decision, the NCUC concluded that a merger was justified by the public convenience and necessity and serves the public interest upon findings that the merger would have no adverse impact on the rates and services provide by the utility, the utility's rate payers were protected as much as reasonably possible from potential costs and risks resulting from the merger, and the known and potential benefits of the merger were sufficient to offset the potential costs and risks. See *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, Docket Nos. E-2, Sub 1095, E-7, Sub 1100, G-9, Sub 682, at 16 (Sept. 29, 2016). On January 24, 2018, Dominion Energy and SCANA filed a joint application with the NCUC seeking approval to engage in the business combination transaction. There is no guarantee that the NCUC will approve the merger or that it will not impose conditions on its approval that are unacceptable to either Dominion Energy or SCANA.

GPSC Approval

Approval of the merger is required under O.C.G.A. § 46-4-25 for the indirect transfer of ownership of SEMI, from SCANA to Dominion Energy. The GPSC must act on an application to amend a certificate of authority to reflect a change in ownership within ninety (90) days from the date the application is deemed complete. On January 19, 2018, Dominion Energy and SEMI filed a joint application with the GPSC seeking approval of the change of ownership. There is no guarantee that the GPSC will approve the indirect transfer of ownership or that it will not impose conditions on its approval that are unacceptable to either Dominion Energy or SCANA.

HSR Act and Antitrust

Completion of the merger is subject to the receipt of antitrust clearance in the United States. Under the HSR Act and the rules and regulations promulgated thereunder, the merger may not be completed until notification and report forms have been filed with the DOJ and the FTC and the applicable waiting period has expired or been terminated.

The waiting period with respect to the notification and report forms filed under the HSR Act expires 30 calendar days after the date both parties have submitted such filings, unless otherwise extended or terminated. Dominion Energy and SCANA filed the required HSR Act notification and report forms with the DOJ and FTC on January 19, 2018, and requested early termination of the HSR Act waiting period. On February 1, 2018, the FTC notified Dominion Energy and SCANA that it had granted early termination of the waiting period.

At any time before or after completion of the merger, notwithstanding the termination of the waiting period under the HSR Act, the DOJ, FTC, or any U.S. state, could take such action under the antitrust laws as each deems necessary or desirable in the public interest, including seeking to enjoin the completion of the merger or seeking divestiture of substantial assets of Dominion Energy and SCANA. Private parties also may seek to take legal action under the antitrust laws under certain circumstances. There can be no assurance that the DOJ, the FTC or any other governmental entity or any private party will not attempt to challenge the merger on antitrust or competition grounds, and, if such a challenge is made, there can be no assurance as to its result. Under the merger agreement, Dominion Energy and SCANA generally must use reasonable best efforts to take all
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necessary actions to obtain all regulatory approvals required to complete the merger, subject to certain exceptions. If the merger is not completed within 12 months after the expiration or early termination of the applicable HSR Act waiting period, Dominion Energy and SCANA will be required to submit new notification and report forms to the DOJ and the FTC, and a new HSR Act waiting period will have to expire or be terminated before the merger can be completed.

FERC Approval

Each of Dominion Energy and SCANA is a holding company under the Public Utility Holding Company Act of 2005, which we refer to as PUHCA, that has subsidiaries that either are “public utilities,” “transmitting utilities,” “electric utilities,” “electric utility companies” or a “holding company in a holding company system that includes a transmitting utility or an electric utility company” as such terms are defined under PUHCA, the FPA and the FERC’s implementing regulations. One of the requirements of Section 203 of the FPA is that no holding company in a holding company system that includes a transmitting utility or an electric utility may purchase, acquire, merge or consolidate with a transmitting utility, an electric utility company or a holding company in a holding company system that includes a transmitting utility or electric utility company without prior FERC authorization. Consequently, the FERC’s approval of the merger under Section 203 of the FPA is required.

The FERC must authorize the merger if it finds that the merger is consistent with the public interest. The FERC has stated that, in analyzing a merger or transaction under Section 203 of the FPA, it will evaluate the impact of the merger on:

- competition in electric power markets;
- the applicants’ wholesale rates; and
- state and federal regulation of the applicants.

The FERC must also find that the merger will not result in the cross-subsidization by utilities of their non-utility affiliates or the improper encumbrance or pledge of utility assets. If such cross-subsidization or encumbrances were to occur as a result of the merger, the FERC then must find that such cross-subsidization or encumbrances are consistent with the public interest.

The FERC will review these factors to determine whether the merger is consistent with the public interest. If the FERC finds that the merger would adversely affect competition in wholesale electric power markets, rates for transmission or the wholesale sale of electric energy, or regulation, or that the merger would result in cross-subsidies or improper encumbrances that are not consistent with the public interest, it may, pursuant to the FPA, impose upon the merger remedial conditions intended to mitigate such effects or it may decline to authorize the merger. The FERC is required to rule on a completed merger application not later than 180 days from the date on which the completed application is filed. The FERC may, however, for good cause, issue an order extending the time for consideration of the merger application by an additional 180 days. If the FERC does not issue an order within the statutory deadline, then the transaction is deemed to be approved. Dominion Energy and SCANA expect that the FERC will approve the merger within the initial 180-day review period. However, there is no guarantee that the FERC will not extend the time period for its review or will not impose conditions on its approval that are unacceptable to Dominion Energy or SCANA.

NRC Approval

Completion of the merger is subject to the issuance of an order by the NRC consenting to the indirect transfer of control of NRC License No. NPF-93, Docket No. 52-027, NRC License No. NPF-94, Docket No. 52-028, and NRC License No. NPF-126, Docket No. 50-395 from SCANA to Dominion Energy as required by Section 184 of the Atomic Energy Act and the NRC’s implementing regulations in 10 C.F.R. 50.80. On

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January 25, 2018, Dominion Energy and SCANA filed an application requesting that NRC issue an order consenting to the indirect transfer of control of the licenses. There is no guarantee that the NRC will consent to the indirect transfer of control or that it will not impose conditions on its consent that are unacceptable to either Dominion Energy or SCANA. In addition, while completion of the merger is not conditioned on their receipt, consent is required for the indirect transfer of control of certain other related licenses issued by the State of South Carolina and the State of Tennessee.

FCC Approval

Under FCC regulations implementing provisions of the Communications Act of 1934, as amended, an entity holding private radio licenses for internal communications purposes generally must obtain the approval of the FCC before the direct or indirect transfer of control or assignment of those licenses. SCANA and certain SCANA subsidiaries hold FCC licenses for private internal communications and, thus, must obtain prior FCC approval to assign or transfer direct or indirect control of those licenses. Once the FCC has consented to the transfer of control, the parties have 180 days to complete the merger. If the merger does not close within 180 days of receiving FCC consent, the parties can request an extension of time to complete the transaction. The FCC customarily grants extension requests of this nature. There is no guarantee that the FCC will consent to the transfer of control or that it will not impose conditions on its consent that are unacceptable to either Dominion Energy or SCANA. Completion of the merger is not conditioned on the receipt of this FCC consent.

Material Contracts between SCANA and Dominion Energy

In December 2014, SCANA and Dominion Energy entered into a definitive agreement for the sale by SCANA of its subsidiary, Carolina Gas Transmission Corporation, to Dominion Energy for approximately $450 million. The sale was completed by the parties in January 2015.

Legislation Relating to the Merger

Following the announcement of the merger, the South Carolina legislature has proposed two (2) pieces of legislation relating to the merger. First, the South Carolina House of Representatives has passed H.4375. This bill, among other things, repeals the BLRA for future projects, restricts SCE&G's ability to file a general rate case proceeding which seeks to recover new nuclear expenses and directs the SCPSC to, within five (5) days of enactment, set an experimental rate that SCE&G would charge ratepayers, the result of which experimental rate would be a reduction in SCE&G's lawfully approved rate revenue of approximately $37,000,000 per month. This bill is currently pending before the South Carolina Senate. If this bill becomes law, Dominion Energy would not be obligated to complete the merger if it is determined that the bill has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries. Second, S.954 is currently pending in the South Carolina Senate. This joint resolution, among other things, prohibits the SCPSC from taking any action on any request made under the BLRA until 90 days after the South Carolina General Assembly adjourns *Sine Die*. If S.954 becomes law, and the House and Senate adjourn *Sine Die* in November 2018 as is presently contemplated, then the SCPSC would not be allowed to take action on matters that are required to satisfy Dominion Energy's conditions to closing under the merger agreement until early 2019, and Dominion Energy would not be obligated to complete the merger until such conditions are satisfied.

Litigation Relating to the Merger

Following the announcement of the merger, three (3) lawsuits have asserted claims relating to the merger. First, a pre-existing lawsuit filed derivatively on behalf of SCANA was amended to assert putative class action claims on behalf of SCANA shareholders in the Court of Common Pleas of the County of Richland, South Carolina: *Firemen's Retirement System of St. Louis v. Addison, et al.*, 2017-CP-400-7547. This lawsuit asserts claims against certain officers of SCANA and members of the SCANA board for breach of fiduciary duties, waste of corporate assets, and unjust enrichment, and against Dominion Energy and Merger Sub for aiding and abetting the alleged breaches of fiduciary duties. Second, two (2) putative class actions on behalf of SCANA

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shareholders have been filed in the Court of Common Pleas of the Counties of Lexington and Richland, South Carolina, respectively: *City of Warren Police and Fire Retirement System v. SCANA Corporation, et al*., 2018-CP-320-0268 and *Metzler Asset Management GmbH and Joseph Heinz v. Aliff, et al*., 2018-CP-400-0816. The first of these lawsuits asserts claims against an officer of SCANA and certain members of the SCANA board for breach of fiduciary duties in connection with the merger, and against SCANA, Dominion Energy and Merger Sub for aiding and abetting the alleged breaches. The second asserts claims against certain members of the SCANA board for breach of fiduciary duties in connection with the merger, and against Dominion Energy and Merger Sub for aiding and abetting the alleged breaches. Collectively, these three (3) lawsuits allege, among other things, that the individual defendants created a false impression to investors and state regulators that the NND project was running smoothly within a reasonable budget and on schedule to increase their compensation and maintain their positions, which has exposed SCANA to billions of dollars in costs and damages in connection with numerous civil and criminal proceedings. The lawsuits also allege that the merger is designed to unlawfully divest SCANA shareholders of their holdings without providing them the maximized value to which they are entitled and without adequate information to evaluate the transaction. Specifically, these plaintiffs allege that the individual defendants were motivated to approve the merger for an inadequate price for the purpose of extinguishing the right of SCANA shareholders to pursue the derivative claims against them to avoid personal liability, and because they will receive significant personal financial benefits in the merger not shared by other SCANA shareholders. The lawsuits also allege that the consideration proposed in the merger fails to adequately account for and value the derivative claims against the individual defendants that Dominion Energy will acquire in the merger, and that because Dominion Energy has agreed to indemnify the individual defendants in the merger agreement, it is unlikely that Dominion Energy will pursue these claims if the merger is consummated. The lawsuits also allege that the merger is unfair to SCANA shareholders because if SCANA were offered the same rate settlement terms that Dominion Energy is proposing in connection with the transaction, SCANA's stock price would increase substantially above the value of the merger consideration. The lawsuits also allege that the merger was the result of a flawed process and self-dealing, that the merger consideration was insufficient and that certain provisions of the merger agreement might dissuade an alternative bidder from surfacing. The lawsuits seek to enjoin the merger and rescind the merger agreement. In addition, the second and third lawsuits seek in the alternative, should the merger be completed, an award of unspecified monetary damages.

Other Legal Proceedings

Certain lawsuits and regulatory actions have been filed against SCANA and SCE&G in connection with the abandonment of the NND project. If the relief requested in these matters (including a request for declaratory judgment that the BLRA is unconstitutional) is granted, Dominion Energy might not be obligated to complete the merger.

Exchange of Shares in the Merger

For a description of the exchange and payment procedures with respect to the shares of SCANA common stock under the merger agreement, please see the section entitled "*The Merger Agreement—Exchange and Payment Procedures*" on page 86 of this proxy statement/prospectus.

Interests of SCANA's Directors and Executive Officers in the Merger

In considering the SCANA board's recommendation that you vote to approve the merger, you should be aware that SCANA's directors and executive officers have economic interests in the merger that are different from, and in addition to, those of SCANA's shareholders generally. These interests, which may create actual or potential conflicts of interests, are, to the extent material, described below. The SCANA board was aware of and considered these interests, among other matters, in evaluating and negotiating the merger agreement, in reaching its decision to approve the merger agreement, and in recommending to SCANA's shareholders that the merger agreement be approved. For the purposes of the SCANA plans and agreements described below, the completion of the transactions contemplated by the merger agreement will constitute a change in control of SCANA.

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Allegations of Shareholder Derivative and Class Action Suits

The directors and officers of SCANA are also alleged to have certain interests in the transaction as described in the section entitled "—*Litigation Relating to the Merger*" beginning on page 71 of this proxy statement/ prospectus.

Equity Compensation

Pursuant to the merger agreement, upon completion of the merger, each performance share award and restricted stock unit award will be cancelled in exchange for a cash payment, as described below. The payment shall be made as soon as reasonably practicable after the effective time of the merger, but in any event within three (3) business days thereafter; *provided*, *however*, that any performance share awards and restricted stock unit awards that are subject to Section 409A of the Code shall be paid at the earliest time permitted under, and in accordance with, the terms of the applicable award agreements and relevant documents and in accordance with Section 409A of the Code.

Treatment of Performance Share Awards

At the effective time of the merger, each performance share award that is outstanding immediately prior to the effective time of the merger will fully vest at the target level of performance and shall be cancelled and converted automatically into the right to receive the following in respect of each share of SCANA common stock underlying such performance share award: (i) the merger consideration multiplied by (ii) the average price, in cash and without interest (we refer to the product of clauses (i) and (ii) in this sentence as the equity award consideration).

Treatment of Restricted Stock Units

At the effective time of the merger, each restricted stock unit award that is outstanding immediately prior to the effective time of the merger will fully vest and be cancelled and converted automatically into the right to receive the equity award consideration in respect of each share of SCANA common stock underlying such restricted stock unit award.

Treatment of Deferred Units

At the effective time of the merger, each deferred unit in respect of SCANA common stock credited or deemed credited to the SCANA stock ledger under the SCANA Director Compensation and Deferral Plan or the SCANA Executive Deferred Compensation Plan that is outstanding immediately prior to the effective time of the merger shall be converted automatically into a number of deferred units in respect of Dominion Energy common stock equal to the product of (i) the deferred unit, multiplied by (ii) the merger consideration, to be payable pursuant to the terms of the applicable plan.

Payments under the Supplementary Key Executive Severance Benefits Plan

The SCANA Corporation Supplementary Key Executive Severance Benefits Plan, which we refer to as the Supplementary Severance Plan, provides for payments to SCANA's senior executive officers if, within twenty-four (24) months after a change in control of SCANA, a senior executive officer's employment is terminated without "just cause" or the senior executive officer terminates his or her employment for "good reason."

Under the Supplementary Severance Plan, SCANA would be deemed to have "just cause" for terminating the employment of a senior executive officer if he or she: (i) willfully and continually failed to substantially perform his or her duties after SCANA made demand for substantial performance; (ii) willfully engaged in conduct that is demonstrably and materially injurious to SCANA; or (iii) were convicted of a felony or certain misdemeanors.
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A senior executive officer would be deemed to have “good reason” for terminating his or her employment under the Supplementary Severance Plan if, after a change in control, without his or her consent, any one or more of the following occurred: (i) a material diminution in his or her base salary; (ii) a material diminution in his or her authority, duties, or responsibilities; (iii) a material diminution in the authority, duties, or responsibilities of the supervisor to whom he or she is required to report, including a requirement that he or she report to one of our officers or employees instead of reporting directly to the SCANA board; (iv) a material diminution in the budget over which he or she retains authority; (v) a material change in the geographic location at which he or she must perform services; or (vi) any other action or inaction that constitutes a material breach by SCANA of the agreement under which he or she provides services.

In the event of such a termination, the Supplementary Severance Plan entitles participants to the following payments and benefits:

- an amount intended to approximate 2.5 times the sum of: (i) his or her annual base salary (before reduction for certain pre-tax deferrals) in effect as of the change in control, plus (ii) his or her full targeted annual incentive opportunity in effect as of the change in control;
- an amount equal to the participant’s full targeted annual incentive opportunity in effect under each existing annual incentive plan or program for the year in which the change in control occurs;
- if the participant’s benefit under the SCANA Corporation Supplemental Executive Retirement Plan, which we refer to as the SERP, is determined using the final average pay formula under the SCANA Corporation Retirement Plan, which we refer to as the Retirement Plan, an amount equal to the present lump sum value of the actuarial equivalent of his or her accrued benefit under the Retirement Plan and the SERP through the date of the change in control, calculated as though he or she had attained age 65 and completed 35 years of benefit service as of the date of the change in control, and as if his or her final average earnings under the Retirement Plan equaled the amount determined after applying cost-of-living increases to his or her annual base salary from the date of the change in control until the date he or she would reach age 65, and without regard to any early retirement or other actuarial reductions otherwise provided in any such plan (this benefit will be offset by the actuarial equivalent of the participant’s benefit provided by the Retirement Plan and the participant’s benefit under the SERP);
- if the participant’s benefit under the SERP is determined using the cash balance formula under the Retirement Plan, an amount equal to the present value as of the date of the change in control of his or her accrued benefit, if any, under the SERP, determined prior to any offset for amounts payable under the Retirement Plan, increased by the present value of the additional projected pay credits and periodic interest credits that would otherwise accrue under the Retirement Plan (based on the Retirement Plan’s actuarial assumptions), assuming that he or she remained employed until reaching age 65, and reduced by his or her cash balance account under the Retirement Plan, and further reduced by an amount equal to his or her benefit under the SERP;
- an amount equal to the value of all amounts credited to each participant’s SCANA Corporation Executive Deferred Compensation Plan, which we refer to as the EDCP, ledger account as of the date of the change in control, plus interest on the benefits payable under the EDCP at a rate equal to the sum of the prime interest rate as published in the Wall Street Journal on the most recent publication date prior to the date of the change in control plus 3%, calculated through the end of the month preceding the month in which the benefits are distributed, reduced by the value of his or her benefit under the EDCP as of the date of the change in control; and
- an amount equal to the projected cost for medical, long-term disability and certain life insurance coverage for three (3) years following the change in control as though he or she had continued to be a SCANA employee.

Pursuant to the merger agreement, with respect to Mr. Addison, Mr. Kissam and Ms. Griffin, if any such executive’s salary has not been adjusted to at least the low point of SCANA’s pre-established salary range for his

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or her applicable pay grade which pay grade was adjusted in respect of recent promotions, benefits under the Supplementary Severance Plan will be provided to such executive as if such executive's salary had been adjusted to the low point. The low point of the salary range represents a salary at 85% of the midpoint of the range for an executive's applicable pay grade.

In addition to the benefits above (unless their agreements with SCANA provide otherwise), participants in the Supplementary Severance Plan are entitled to benefit distribution under the Long-Term Equity Compensation Plan equal to 100% of the target awards for all performance periods not completed as of the date of the change in control, if any; however, the treatment of equity awards is prescribed under the merger agreement and further described under "*Interests of SCANA's Directors and Executive Officers in the Merger—Equity Compensation*" above. Participants in the Supplementary Severance Plan are also be entitled to any amounts previously earned, but not yet paid, under the terms of any of SCANA's other plans or programs.

Retirement Benefits

Supplemental Executive Retirement Plan

The SERP is an unfunded nonqualified defined benefit plan that was established for the purpose of providing supplemental retirement income to certain SCANA employees, including the executive officers. Subject to the terms of the SERP, a participant becomes eligible to receive benefits under the SERP upon termination of his or her employment with SCANA (or at such later date as may be provided in a participant's agreement), if the participant has become vested in his or her accrued benefit under the Retirement Plan prior to termination of employment. However, if a participant is involuntarily terminated following or incident to a change in control and prior to becoming fully vested in his or her accrued benefit under the Retirement Plan, the participant will automatically become fully vested in his or her benefit under the SERP and a benefit will be payable under the SERP.

Executive Deferred Compensation Plan

The EDCP is a nonqualified deferred compensation plan in which SCANA's executive officers, including the named executive officers, and SCANA's directors, may participate. Amounts deferred under the EDCP are required to be paid, or begin to be paid, as soon as practicable following the earliest of a participant's death, separation from service, or with respect to pre-2005 deferrals and hypothetical earnings thereon, disability.

Director Deferred Compensation

The Director Compensation and Deferral Plan, which we refer to as the DCDP, is a nonqualified deferred compensation plan pursuant to which SCANA's non-employee directors may defer annual stock and cash retainer fees. Amounts are generally paid, or begin to be paid, on a separation from service from the SCANA board for any reason or a date certain previously elected by the director (and subject to the ability to make subsequent deferrals pursuant to the terms set forth in the DCDP). In addition, one director has an account balance under the Voluntary Deferral Plan, a nonqualified deferred compensation plan that was closed effective January 1, 2001, which account balance will generally be paid, or begin to be paid, upon separation from service from the SCANA board for any reason (and subject to the ability to make subsequent deferrals pursuant to the terms set forth in the Voluntary Deferral Plan).

Director Endowment Plan

The SCANA Director Endowment Plan, which was closed to new participants effective January 1, 2013, provides for SCANA to make tax deductible, charitable contributions totaling $500,000 per eligible director to institutions of higher education designated by the applicable director. A portion is contributed upon retirement of the director and the remainder upon the director's death.

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Agreements with Dominion Energy

As of the date of this proxy statement/prospectus, none of the SCANA executive officers has entered into any agreement with Dominion Energy or any of its affiliates regarding employment with, or the right to purchase or participate in the equity of, Dominion Energy or one or more of its affiliates. Prior to or following the closing of the merger, however, some or all of the SCANA executive officers may discuss or enter into agreements with Dominion Energy or any of its affiliates regarding employment with, or the right to purchase or participate in the equity of, Dominion Energy or one or more of its affiliates. For information on Dominion Energy's directors and management after the merger, please see the section entitled "—*Directors and Management of Dominion Energy After the Merger*" beginning on page 65 of this proxy statement/prospectus.

Director and Officer Indemnification

Under the merger agreement, after the effective time of the merger, the SCANA directors and officers are entitled to continued indemnification and insurance coverage relating to their service as SCANA directors and officers prior to the effective time of the merger. For a more complete description, please see the section entitled "*The Merger Agreement—Indemnification and Insurance*" beginning on page 105 of this proxy statement/prospectus.

Potential Payments upon a Termination in Connection with a Change in Control

In accordance with Item 402(t) of Regulation S-K, the table below sets forth the estimated amounts of compensation that are based on or otherwise relate to the merger and that may be payable to those individuals who were listed in the "Summary Compensation Table" that was set out in SCANA's most recent securities filing for which disclosure was required under Item 402(c) of Regulation S-K other than executive officers who cease to be employed by SCANA during 2017 but including Ms. Griffin, who became Chief Financial Officer of SCANA effective January 1, 2018. We refer to these individuals as the "named executive officers."

Please see the section entitled "*The Merger — Interests of SCANA's Directors and Executive Officers in the Merger*" for further information about the compensation disclosed in the table below. The amounts shown in the table below are estimates based on multiple assumptions that may or may not actually occur or be accurate on the relevant date, including the assumptions described below and in the footnotes to the table. This document is being filed before SCANA's Compensation Committee has determined base salary adjustments for 2018, annual target incentive awards for 2018, or equity grants for 2018, all of which determinations are typically made in February of each year and are expected to be made in the latter half of February 2018. Accordingly, for purposes of calculating the amounts set forth below, the following assumptions have been made: for each of Mr. Addison, Mr. Kissam, and Ms. Griffin, his or her salary has been assumed to be adjusted to the low point of the pre-established salary range for his or her applicable pay grade (which pay grade was adjusted in respect of recent promotions), and each was assumed to receive a 2018 annual target incentive award and equity grants based on the pay grade and adjusted salary. The amounts in the table do not otherwise reflect certain compensation actions that may occur before completion of the merger, including certain compensation actions that SCANA is permitted to take prior to the completion of the merger, as described in the section entitled "*The Merger Agreement—Conduct of Business*." For purposes of calculating such amounts, the following additional assumptions were used:

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- the relevant price per share of SCANA common stock is $45.19, which is the average closing price of a share of SCANA common stock over the first five (5) business days following the first public announcement of the merger agreement;

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- the effective time of the merger is September 30, 2018, which is the assumed date of completion of the merger solely for purposes of the disclosure in this section; and

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- the employment of each executive officer of SCANA will have been terminated by Dominion Energy without cause or due to the executive officer's resignation for good reason, as such terms are defined in

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the relevant plans and agreements, in either case following the assumed effective time of the merger on September 30, 2018.

Merger-Related Compensation

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Named Executive Officer	Cash ($)(1)	Equity($)(2)	Pension/NQDC ($)(3)	Perquisites/ Benefits($)	Tax Reimbursement ($)	Other ($)	Total ($)
K. B. Marsh(4)	$ 0	$3,058,911	$ 0	$ 0	$ 0	$ 0	$ 3,058,911
J. E. Addison	$5,297,314	$4,257,356	$ 845,547	$ 0	$ 0	$ 0	$10,400,217
S. A. Byrne(4)	$ 0	$1,111,410	$ 0	$ 0	$ 0	$ 0	$ 1,111,410
W. K. Kissam	$2,369,140	$1,442,425	$ 343,966	$ 0	$ 0	$ 0	$ 4,155,531
I. N. Griffin	$1,941,402	$ 716,382	$ 251,681	$ 0	$ 0	$ 0	$ 2,909,465

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(1) Cash. The amounts listed in this column consist of (a) an amount equal to 2.5 times the sum of base salary and target short-term incentive award, (b) an amount equal to the full target annual incentive opportunity for the year in which the merger occurs, and (c) an amount equal to the projected cost for insurance benefits for three years. All such benefits are "double trigger" and are provided only on a termination without just cause or resignation for good reason during the period within twenty-four (24) months after a change in control of SCANA. For further details, see the section entitled "*—Interests of SCANA's Directors and Executive Officers in the Merger—Payments under the Supplementary Key Executive Severance Benefits Plan*." Messrs. Marsh and Byrne retired January 1, 2018 and are not eligible for any severance as a result of the merger.

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Named Executive Officer	Severance	Target Bonus	Amount Related to Benefits	Total
K. B. Marsh(4)	$ 0	$ 0	$ 0	$ 0
J. E. Addison	$4,395,223	$ 832,779	$ 69,312	$5,297,314
S. A. Byrne(4)	$ 0	$ 0	$ 0	$ 0
W. K. Kissam	$1,968,410	$ 310,174	$ 90,556	$2,369,140
I. N. Griffin	$1,617,720	$ 242,658	$ 81,024	$1,941,402

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(2) Equity. Consists of (a) unvested performance share awards and (b) unvested restricted stock units (each including dividend equivalents) that will become vested at the effective time of the merger and paid out in cash as described above pursuant to the merger agreement. Pursuant to the merger agreement, all such benefits are "single trigger." For Messrs. Marsh and Byrne, only a pro rata portion of the performance shares (relating to the period during which each was employed) is included pursuant to the terms of their award agreements. For further details regarding the treatment of SCANA equity awards in connection with the merger, see the section entitled "*—Interests of SCANA's Directors and Executive Officers in the Merger—Equity Compensation*."

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Named Executive Officer	Performance Share Awards	Restricted Stock Units	Total
K. B. Marsh(4)	$ 1,622,177	$ 1,436,734	$3,058,911
J. E. Addison	$ 2,972,874	$ 1,284,482	$4,257,356
S. A. Byrne(4)	$ 589,376	$ 522,034	$1,111,410
W. K. Kissam	$ 1,006,914	$ 435,511	$1,442,425
I. N. Griffin	$ 501,829	$ 214,553	$ 716,382

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(3) Pension/Non-Qualified Deferred Compensation. Consists of increased payments pursuant to the EDCP, (with interest as provided under the Supplementary Severance Plan), and the SERP (including the excess payable as provided under the Supplementary Severance Plan). All such benefits are "double trigger." For further details, see the section entitled "*—Interests of SCANA's Directors and Executive Officers in the*

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Merger." Messrs. Marsh and Byrne retired January 1, 2018 and are not eligible for any pension/non-qualified deferred compensation benefit as a result of the merger.

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(4) Messrs. Marsh and Byrne retired effective January 1, 2018.

Dividends

Dominion Energy currently pays a quarterly dividend of $0.835 per share. SCANA currently pays a quarterly dividend of $0.6125 per share and has agreed in the merger agreement that it will not increase such dividend prior to the completion of the merger without Dominion Energy's prior written consent. Following the closing of the merger, Dominion Energy expects to continue its current dividend for shareholders of the combined company, subject to any factors that the Dominion Energy board in its discretion deems relevant. For additional information on the treatment of dividends under the merger agreement, see the section entitled "*The Merger Agreement—Conduct of Business*" beginning on page 101 of this proxy statement/prospectus.

Listing of Dominion Energy Common Stock

Shares of Dominion Energy common stock currently trade on the NYSE under the stock symbol "D." It is a condition to the completion of the merger that Dominion Energy common stock issuable in the merger be approved for listing on the NYSE, subject to official notice of issuance. Dominion Energy has agreed to use its reasonable best efforts to cause Dominion Energy common stock issuable in connection with the merger to be approved for listing on the NYSE and expects to obtain NYSE's approval to list such shares prior to completion of the merger, subject to official notice of issuance.

Delisting and Deregistration of SCANA Common Stock

Shares of SCANA common stock currently trade on the NYSE under the stock symbol "SCG." SCANA has agreed pursuant to the merger agreement to cooperate with Dominion Energy to use its reasonable best efforts to take all actions, and do or cause to be done all things, reasonably necessary, proper or advisable on its part under applicable laws and rules and regulations of the NYSE to enable the delisting of SCANA common stock from the NYSE and deregistration of SCANA common stock under the Exchange Act as promptly as practicable after the effective time of the merger.

Certain Forecasts Prepared by SCANA's Management

While SCANA provides public earnings guidance from time to time, SCANA does not as a matter of course publicly disclose other financial forecasts as to future earnings or financial performance or results because of, among other reasons, the uncertainty underlying assumptions and estimates. However, SCANA's management prepared and provided the SCANA board with certain non-public financial forecasts in connection with the SCANA board's consideration and evaluation of a possible merger with Dominion Energy. As described below, certain of these financial forecasts were also provided to SCANA's financial advisors, Morgan Stanley and RBC Capital Markets, for their use and reliance in connection with their respective financial analyses and opinions summarized in "*—Opinions of SCANA's Financial Advisors*" beginning on page 47 of this proxy statement/prospectus. In addition, as described below, certain of these financial forecasts were provided to Dominion Energy and its advisors in connection with the proposed transaction.

Neither SCANA's independent auditors nor any other independent accountants have compiled, examined, or performed any procedures with respect to the prospective financial information contained herein, nor have they expressed any opinion or any other form of assurance on such information or its achievability, and assume no responsibility for, and disclaim any association with, the prospective financial information. Further, the report of SCANA's independent auditors included in this proxy statement/prospectus relates to SCANA's historical financial information. It does not extend to prospective financial information and should not be read to do so.

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SCANA has included a summary of these financial forecasts to give SCANA shareholders access to certain non-public information made available to the SCANA board, SCANA's advisors, and Dominion Energy and its advisors in connection with the proposed transaction with Dominion Energy. SCANA has not included these financial forecasts to influence the decision of the SCANA shareholders as to whether to vote for or against the merger proposal.

The inclusion of this information should not be regarded as an indication that SCANA, Dominion Energy or any of their respective affiliates, directors, officers, employees, agents, advisors or other representatives considered, or now considers, such financial forecasts to be material or to be necessarily predictive of actual future results, and readers are cautioned not to place undue reliance on this information.

The financial forecasts have been prepared by, and are the responsibility of, SCANA's management. SCANA's management believes that the financial forecasts were prepared in good faith and on a reasonable basis based on the best information available to SCANA's management when prepared. The financial forecasts were not prepared with a view toward complying with GAAP, the published guidelines of the SEC regarding projections and the use of non-GAAP measures, or the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of prospective financial information.

The financial forecasts include non-GAAP financial measures, which were presented because SCANA's management believed they could be useful indicators of SCANA's projected future operating performance and cash flow. However, non-GAAP measures presented in the financial forecasts may not be comparable to similarly titled measures of other companies.

The financial forecasts prepared by SCANA's management were prepared for SCANA's internal use and not with a view toward public disclosure and are subjective in many respects. As a result, there can be no assurance that the prospective earnings or financial performance or results set forth in the financial forecasts will be realized or that actual future results will not be significantly higher or lower than estimated. These financial forecasts were based on numerous variables, which are inherently uncertain and may be beyond SCANA's control. Since the financial forecasts cover multiple years, by their nature, they become subject to greater uncertainty with each successive year. Important factors that may affect actual results and cause these financial forecasts not to be achieved include, but are not limited to, risks and uncertainties relating to SCANA's business, regulatory decisions and the regulatory environment generally, changes in applicable laws, general business and economic conditions, the occurrence of unusual weather events, and other factors described or referenced under "*Cautionary Statement Regarding Forward-Looking Statements*" beginning on page 25 of this proxy statement/prospectus.

In addition, financial forecasts also reflect assumptions that are subject to change and do not reflect revised prospects for our business, changes in applicable laws or regulations, changes in general business or economic conditions or any other transaction or event that has occurred or that may occur subsequent to the time the financial forecasts were prepared and that was not anticipated at the time the financial forecasts were prepared. The financial forecasts also do not take into account the merger or other transactions contemplated by the merger agreement or the effect of the failure of the merger to occur, and should not be viewed as necessarily indicative of actual or continuing results in that context.

Accordingly, there can be no assurance that the financial forecasts will be realized, and actual results may vary materially from those shown, including because of the risks and other factors described in the section entitled "*Cautionary Statement Regarding Forward-Looking Statements*" beginning on page 25 of this proxy statement/prospectus. None of SCANA, Dominion Energy or any of their respective affiliates, directors, officers, employees, agents, advisors or other representatives gives or can give any assurance that actual results will not differ from the financial forecasts, and none of SCANA, Dominion Energy or any of their respective affiliates, directors, employees, agents, advisors or other representatives undertakes any obligation to update or otherwise revise or reconcile the financial forecasts to reflect circumstances existing after the date the financial forecasts
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were generated or to reflect the occurrence of future events even in the event that any or all of the assumptions underlying the financial forecasts are shown not to be appropriate.

SCANA does not intend to make publicly available any update or other revision to the financial forecasts, except as otherwise required by law. None of SCANA, Dominion Energy or any of their respective affiliates, directors, officers, employees, agents, advisors or other representatives has made or makes any representation or warranty to any shareholder of SCANA or other person regarding the ultimate performance of SCANA compared to the information contained in the financial forecasts or that the financial forecasts will be achieved. The financial forecasts do not take into account any circumstances or events occurring after the date on which such forecasts were prepared.

Additional information relating to the principal assumptions used in preparing the projections is set forth below. See the section entitled "*Risk Factors*" on page 17 of this proxy statement/prospectus for a discussion of various factors that could materially affect SCANA's financial condition, results of operations, business, prospects and securities.

The financial forecasts were prepared based on SCANA's management's belief that it was preferable to seek a settlement that offered a comprehensive solution to the outstanding rate and regulatory issues relating to the abandoned NND project in order to resolve those issues rather than pursue an outcome that did not include such a settlement. In light of that context, SCANA's management prepared financial forecasts (taking into account SCANA's management's views on the estimated anticipated effect of the U.S. tax reform enacted on December 22, 2017, referred to as the Tax Cuts and Jobs Act of 2017) under various settlement scenarios, each of which reflect the following material assumptions:

- A compound annual growth rate, which we refer to as CAGR, of revenues for SCANA's gas business from FY2018E through FY2022E as follows:
  - SCE&G: 4.5%;
  - PSNC: 5.7%; and
  - SEMI: 3.1%; and
- A CAGR of SCANA's Operations and Maintenance growth from FY2018E through FY2022E of approximately 0.3%.

The specific regulatory settlement scenarios prepared by SCANA's management and focused on by the SCANA board in connection with the proposed transaction were a 5% regulatory settlement scenario and a 9.75% regulatory settlement scenario, which scenarios SCANA directed Morgan Stanley and RBC Capital Markets to use and rely upon for purposes of their respective financial analyses and opinions in connection with the proposed transaction without ascribing any relative weighting, probability or likelihood of success to either scenario. The financial forecasts under the 5% regulatory settlement scenario reflect circumstances under which SCE&G would provide a 5% reduction in electricity rates and an upfront cash refund to customers that would provide a higher benefit to customers than the publicly disclosed 3.5% regulatory settlement scenario (described below). The financial forecasts under the 9.75% regulatory settlement scenario reflect circumstances under which SCE&G would provide the largest reduction in electricity rates it could on a stand-alone basis while still maintaining an investment-grade credit rating for SCANA. The following are the material assumptions for the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario:

- 5% regulatory settlement scenario:
  - SCE&G reduces its retail electricity rates by 5% from current levels, an aggregate discount of approximately $125 million per year;
  - SCE&G writes-off approximately $697 million in assets;
  - SCE&G provides its electric customers a one-time $500 million credit in 2018;

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- SCANA repurchases approximately $300 million of its shares of common stock through 2022;
- SCE&G purchases a natural gas-fired power station for approximately $180 million in order to increase electricity generation, for which the acquisition cost will not be recovered from customers and only certain ongoing costs will be recovered in future base and fuel rates; and
- SCE&G absorbs through existing revenues approximately $3.0 billion in nuclear construction amortization costs over 50 years.

- 9.75% regulatory settlement scenario:
  - SCE&G reduces its retail electricity rates by 9.75% from current levels, an aggregate discount of approximately $233 million per year;
  - SCE&G writes-off approximately $1.83 billion in assets;
  - SCANA does not repurchase any of its shares of common stock;
  - SCE&G purchases a natural gas fired power station for approximately $180 million in order to increase electricity generation, for which the acquisition cost will not be recovered from customers and only certain ongoing costs will be recovered in future base and fuel rates; and
  - SCE&G absorbs through existing revenues approximately $1.9 billion in nuclear construction amortization costs over 50 years.

The following is a summary of the financial forecasts prepared by SCANA's management regarding SCANA for the fiscal years ending 2018 through 2022 under each of the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario:

5% Regulatory Settlement Scenario

	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E
	(in $ millions, except for per share data)				
Revenues	3,908	4,512	4,577	4,693	4,845
EBITDA	997	1,471	1,514	1,593	1,649
EBIT	(324)	972	1,004	1,054	1,102
Net Income	(510)	480	505	550	594
Weighted-Average Outstanding Shares	142.9	142.9	142.9	141.9	139.9
Earnings Per Share	($ 3.57)	$ 3.36	$ 3.53	$ 3.87	$ 4.24
Normalized Net Income(1)	537	480	505	550	594
Adjusted Earnings Per Share(1)	$ 3.76	$ 3.36	$ 3.53	$ 3.87	$ 4.24
Dividend Per Share	2.45	2.43	2.43	2.43	2.58
Capital Expenditures (including Other Investing)	1,034	792	876	882	848

(1) In FY2018E, excludes a net of tax write-off and one-time credit of approximately $1.04 billion in assets with an earnings per share impact of $7.33.

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9.75% Regulatory Settlement Scenario

	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E
	(in $ millions, except for per share data)				
Revenues	4,350	4,398	4,463	4,580	4,732
EBITDA	1,438	1,358	1,401	1,480	1,536
EBIT	(1,004)	890	922	972	1,022
Net Income	(1,020)	418	442	486	531
Weighted-Average Outstanding Shares	142.9	142.9	142.9	142.9	142.9
Earnings Per Share	($ 7.13)	$ 2.92	$ 3.09	$ 3.40	$ 3.71
Normalized Net Income(1)	510	418	442	486	531
Adjusted Earnings Per Share(1)	$ 3.57	$ 2.92	$ 3.09	$ 3.40	$ 3.71
Dividend Per Share	2.45	2.41	2.41	2.41	2.41
Capital Expenditures (including Other Investing)	1,034	792	876	882	848

(1) In FY2018E, excludes a net of tax write-off of approximately $1.53 billion in assets with an earnings per share impact of $10.70.

In addition to the financial forecasts under the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario, SCANA's management prepared and provided to the SCANA board and SCANA's financial advisors for informational purposes financial forecasts under the following scenario, which reflects the following material assumptions:

- 3.5% regulatory settlement scenario:
  - SCE&G reduces its retail electricity rates by 3.5% from current levels, an aggregate discount of approximately $90 million per year;
  - SCE&G writes-off approximately $330 million in assets (which, disregarding the effects of the Tax Cuts and Jobs Act of 2017, equates to a write-off of approximately $811 million in assets);
  - SCANA repurchases approximately $650 million of its shares of common stock through 2022;
  - SCE&G purchases a natural gas fired power station for approximately $180 million in order to increase electricity generation, for which the acquisition cost will not be recovered from customers and only certain ongoing costs will be recovered in future base and fuel rates; and
  - SCE&G absorbs through existing revenues on equity approximately $3.4 billion in nuclear construction amortization costs over 50 years (which, disregarding the effects of the Tax Cuts and Jobs Act of 2017, equates to approximately $2.9 billion in nuclear construction amortization costs over 50 years).

The terms of the 3.5% regulatory settlement scenario had been publicly proposed by SCANA on November 16, 2017. Based on the reaction from legislators and other stakeholders to the proposal, it quickly became clear that the terms of the 3.5% regulatory settlement scenario, in the view of SCANA's management and the SCANA board, were not an acceptable solution to the rate and regulatory issues relating to the abandoned NND project. Accordingly, SCANA directed Morgan Stanley and RBC Capital Markets not to use and rely upon the financial forecasts under the 3.5% regulatory settlement scenario for purposes of their respective financial analyses and opinions in connection with the proposed transaction.

The financial forecasts under the 3.5% regulatory settlement scenario were provided to Dominion Energy and its advisors in connection with the proposed transaction. The financial forecasts under the 5% regulatory settlement scenario and the 9.75% regulatory settlement scenario were not provided to Dominion Energy or its advisors because, in the view of SCANA's management, such financial forecasts were not relevant to Dominion Energy's valuation of SCANA in light of the fact that they reflected scenarios considered by the management of

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SCANA, based on its judgment and the financial resources of SCANA as a standalone company, whereas any regulatory settlement ultimately proposed by Dominion Energy would reflect the judgments and strategy of Dominion Energy's management and the financial resources of a much larger company (Dominion Energy) that would include SCANA.

The following is a summary of the financial forecasts prepared by SCANA's management regarding SCANA for the fiscal years ending 2018 through 2022 under the 3.5% regulatory settlement scenario:

3.5% Regulatory Settlement Scenario

	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E
	(in $ millions, except for per share data)				
Revenues	4,429	4,552	4,617	4,733	4,885
EBITDA	1,517	1,511	1,554	1,633	1,689
EBIT	562	1,014	1,045	1,093	1,139
Net Income	162	513	537	579	621
Weighted-Average Outstanding Shares	142.9	142.2	140.4	137.7	135.1
Earnings Per Share	$ 1.14	$ 3.61	$ 3.82	$ 4.21	$ 4.60
Normalized Net Income(1)	551	513	537	579	621
Adjusted Earnings Per Share(1)	$ 3.85	$ 3.61	$ 3.82	$ 4.21	$ 4.60
Dividend Per Share	2.48	2.51	2.66	2.89	3.13
Capital Expenditures (including Other Investing)	1,034	792	876	882	848

(1) In FY2018E, excludes a net of tax write-off of approximately $389 million in assets with an earnings per share impact of $2.71.

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THE MERGER AGREEMENT

The following summarizes material provisions of the merger agreement, which is attached as Annex A to this proxy statement/prospectus and is incorporated by reference herein. The rights and obligations of the parties are governed by the express terms and conditions of the merger agreement and not by this summary or any other information contained in this proxy statement/prospectus. SCANA shareholders are urged to read the merger agreement carefully and in its entirety as well as this proxy statement/prospectus before making any decisions regarding the merger.

In reviewing the merger agreement, please remember that it is included to provide you with information regarding its terms and is not intended to provide any other factual information about Dominion Energy or SCANA. The merger agreement contains representations and warranties by each of the parties to the merger agreement. These representations and warranties have been made solely for the benefit of the other parties to the merger agreement and:

- may be intended not as statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- have been qualified by certain confidential disclosures that were made to the other party in connection with the negotiation of the merger agreement, which disclosures are not reflected in the merger agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material by you or other investors; and
- information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the merger agreement.

Accordingly, the representations and warranties and other provisions of the merger agreement should not be read alone, but instead should be read together with the information provided elsewhere in this proxy statement/prospectus and in the documents incorporated by reference herein. See the section entitled "*Where You Can Find More Information*" on page 136 of this proxy statement/prospectus.

Effects of the Merger

The merger agreement provides for the merger of Merger Sub with and into SCANA upon the terms and subject to the conditions set forth in the merger agreement and in accordance with the SCBCA. Upon completion of the merger, the separate corporate existence of Merger Sub will cease and SCANA will be the surviving corporation and a wholly owned subsidiary of Dominion Energy.

At the effective time of the merger:

- each share of SCANA common stock issued and outstanding immediately prior to the effective time of the merger (other than cancelled shares), whether represented by a certificate or in non-certificated form and represented by book-entry, will be automatically converted into the right to receive the merger consideration, as may be adjusted in accordance with the immediately following sentence. The merger consideration will be adjusted to reflect the effect of any reclassification, stock split (including a reverse stock split), stock dividend or distribution, recapitalization, exchange or readjustment of shares, merger, issuer tender or exchange offer or other similar transaction with respect to the shares of either Dominion Energy common stock or SCANA common stock that occurs between the date of the merger agreement and the effective time of the merger to provide SCANA shareholders the same economic effect as provided under the merger agreement before such change;
- each performance share award outstanding immediately prior to the effective time of the merger shall fully vest at the target level of performance and shall be cancelled and converted automatically into the right to receive the equity award consideration in respect of each share of SCANA common stock underlying such performance share award;

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- each restricted stock unit award outstanding immediately prior to the effective time of the merger shall fully vest and shall be cancelled and converted automatically into the right to receive the equity award consideration in respect of each share of SCANA common stock underlying such restricted stock unit; and

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- each deferred unit credited or deemed credited to SCANA's stock ledger under SCANA's Director Compensation and Deferral Plan or Executive Deferred Compensation Plan that is outstanding immediately prior to the effective time of the merger will be automatically converted into a number of deferred unit(s) in respect of shares of Dominion Energy common stock equal to the product of (i) the deferred unit multiplied by (ii) the merger consideration, to be payable pursuant to the terms of the applicable plan.

Dominion Energy will issue cash in lieu of fractional shares of Dominion Energy common stock in the merger. Each SCANA shareholder who would otherwise be entitled to receive fractional shares of Dominion Energy common stock in the merger (after aggregating all fractional shares of Dominion Energy common stock issuable to such SCANA shareholder) will be entitled to an amount of cash, without interest, rounded to the nearest cent, equal to the product of (i) the amount of such fractional shares of Dominion Energy common stock issuable to such SCANA shareholder and (ii) the average price.

At the effective time of the merger, each cancelled share will cease to be outstanding, will be cancelled without payment of any consideration therefor and shall cease to exist.

At the effective time of the merger, each share of common stock, without par value, of Merger Sub issued and outstanding immediately prior to the effective time of the merger will be automatically converted into and become one (1) share of common stock, without par value, of the surviving corporation, and all such shares together shall constitute the only outstanding shares of capital stock of the surviving corporation.

Amendments to Organizational Documents; Directors and Officers

The restated articles of incorporation of SCANA, as amended, which we refer to collectively as the SCANA charter, as in effect immediately prior to the effective time of the merger will be the articles of incorporation of the surviving corporation until thereafter amended in accordance with the provisions thereof and applicable law, except that no such amendment will be inconsistent with Dominion Energy's obligation to honor the provisions regarding exculpation of directors, limitation of liability of directors and officers, advancement of expenses and indemnification contained in SCANA's and its subsidiaries' respective organizational documents in existence immediately prior to the effective time of the merger. See the section entitled "*The Merger Agreement—Indemnification and Insurance*" on page 105 of this proxy statement/prospectus.

The amended and restated bylaws of SCANA, which we refer to as the SCANA bylaws, as in effect immediately prior to the effective time of the merger will be amended as of the effective time of the merger to be in the form of Merger Sub's bylaws as of the date of the merger agreement, except with respect to the name of the surviving corporation which shall be "SCANA Corporation," and as so amended will be the bylaws of the surviving corporation until thereafter amended in accordance with the provisions thereof and applicable law, except that no such amendment will be inconsistent with Dominion Energy's obligation to honor the provisions regarding exculpation of directors, limitation of liability of directors and officers, advancement of expenses and indemnification contained in SCANA's and its subsidiaries' respective organizational documents in existence immediately prior to the effective time of the merger. Furthermore, the bylaws of the surviving corporation following the effective time of the merger will include any changes necessary so that such bylaws comply with the provisions in the merger agreement relating to indemnification and insurance coverage for SCANA's directors and officers. See the section entitled "*The Merger Agreement—Indemnification and Insurance*" on page 105 of this proxy statement/prospectus.

The directors of Merger Sub will be appointed by Dominion Energy pursuant to applicable law to be the directors of the surviving corporation after the effective time of the merger, following the resignation or removal

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of the individuals serving as directors of SCANA prior to the effective time of the merger. Such directors will serve until their respective successors have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the surviving corporation's articles of incorporation and bylaws. Dominion Energy intends that the Dominion Energy board will take all necessary action as soon as practicable after the effective time of the merger to appoint a member of either the SCANA board or SCANA's executive management that is mutually agreeable to Dominion Energy and SCANA to serve as a director on the Dominion Energy board.

The officers of SCANA immediately prior to the effective time of the merger will, from and after the effective time of the merger, be the officers of the surviving corporation, until their respective successors have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the surviving corporation's articles of incorporation and bylaws.

Completion of the Merger

The closing of the merger will take place on the third (3rd) business day following the day on which all of the conditions to closing (see the section entitled "*The Merger Agreement—Conditions to Completion of the Merger*" on page 88 of this proxy statement/prospectus) have been satisfied or waived (other than those conditions that by their nature are to be satisfied at the closing of the merger, but subject to the satisfaction or waiver of those conditions at the closing), or at such other time and place as SCANA and Dominion Energy may agree in writing.

The merger will become effective at the time when SCANA and Dominion Energy file the articles of merger with respect to the merger with the Secretary of State of the State of South Carolina or at such later time as Dominion Energy and SCANA agree in writing and specify such time in the articles of merger.

Exchange and Payment Procedures

Prior to the effective time of the merger, Dominion Energy will select an exchange agent reasonably acceptable to SCANA, which we refer to as the exchange agent. Dominion Energy will enter into an agreement with the exchange agent in form and substance reasonably acceptable to SCANA pursuant to which the exchange agent will (i) act as agent for the SCANA shareholders in connection with the merger and receive payment and delivery of the merger consideration to which the SCANA shareholders shall become entitled pursuant to the merger agreement and (ii) act as agent for Dominion Energy in transmitting the merger consideration to the SCANA shareholders following the effective time of the merger in accordance with the merger agreement. At or prior to the effective time of the merger, Dominion Energy will deposit or cause to be deposited with the exchange agent, in trust for the benefit of the SCANA shareholders, an amount of shares of Dominion Energy common stock in book-entry form sufficient for the exchange agent to deliver the merger consideration required to be paid and delivered by Dominion Energy pursuant to the merger agreement. Dominion Energy will also deposit or cause to be deposited with the exchange agent from time to time following the effective time of the merger (i) any dividends or other distributions payable pursuant to the merger agreement (as described below in the section entitled "The Merger Agreement—Exchange and Payment Procedures"), which we refer to as the dividend payment and (ii) any cash in lieu of fractional shares of Dominion Energy common stock payable pursuant to the merger agreement (see the section entitled "*The Merger Agreement—Terms of the Merger*" on page 84 of this proxy statement/prospectus), which we refer to as the fractional shares payment.

Promptly after the effective time of the merger (and in any event within three (3) business days thereafter), Dominion Energy will cause the exchange agent to mail or otherwise provide to each person who was, as of immediately prior to the effective time of the merger, a holder of record of shares of SCANA common stock (other than holders of cancelled shares) transmittal materials, including a letter of transmittal, and instructions for effecting the surrender of SCANA common stock to the exchange agent.

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Upon surrender of SCANA stock certificates, or an affidavit of loss in lieu of such SCANA stock certificates along with the posting of a bond, if required by the exchange agent or Dominion Energy, for cancellation, in accordance with the instructions set forth in the transmittal materials, a SCANA shareholder will be entitled to receive the number of shares of Dominion Energy common stock equal to the number of shares of SCANA common stock represented by such SCANA stock certificates (or affidavit of loss in lieu of such SCANA stock certificates) multiplied by the merger consideration (subject to the treatment of fractional shares described in the section entitled "*The Merger Agreement—Terms of the Merger*" on page 84 of this proxy statement/prospectus) and a cash amount equal to the dividend payment and the fractional shares payment such SCANA shareholder has the right to receive pursuant to the merger agreement. The shares of Dominion Energy common stock issued in exchange for such SCANA stock certificates will be in non-certificated, book-entry form and no interest will be paid or accrued on any cash amount payable upon surrender of such SCANA stock certificates.

Holders of SCANA common stock in book-entry form, which we refer to as book-entry shares, will not be required to obtain and deliver SCANA stock certificates or an executed letter of transmittal to the exchange agent in order to receive the merger consideration that such holder is entitled to receive. Instead, each holder of record of book-entry shares (other than cancelled shares) will be deemed to have surrendered such book-entry shares upon receipt by the exchange agent of an "agent's message" in customary form (or such other evidence, if any, as the exchange agent may reasonably request). Upon the exchange agent's receipt of such an "agent's message," each such holder of book-entry shares will be entitled to receive, and Dominion Energy will cause the exchange agent to pay and deliver as promptly as practicable following the effective time of the merger, to each such holder of book-entry shares, the number of shares of Dominion Energy common stock equal to the number of book-entry shares held by such holder multiplied by the merger consideration (subject to the treatment of fractional shares described in the section entitled "*The Merger Agreement—Terms of the Merger*" on page 84 of this proxy statement/prospectus) and a cash amount equal to the dividend payment and the fractional shares payment such holder has the right to receive pursuant to the merger agreement. The shares of Dominion Energy common stock issued in exchange for such book-entry shares will be in non-certificated, book-entry form and no interest will be paid or accrued on any cash amount payable upon surrender of such book-entry shares.

At any time after the effective time of the merger, until surrendered or exchanged in the manner contemplated above, each share of SCANA common stock will be deemed to represent only the right to receive, upon such surrender or exchange, the merger consideration, the dividend payment and the fractional shares payment. Dominion Energy is required to pay or cause to be paid all charges and expenses of the exchange agent set forth in the agreement with the exchange agent.

Any merger consideration and any amounts with respect to the aggregate dividend payments and the aggregate fractional share payments deposited with the exchange agent (including the proceeds of any investment thereof) that remain undistributed one (1) year after the effective time of the merger will be delivered to Dominion Energy or the surviving corporation upon demand by Dominion Energy. Thereafter, any holders of shares of SCANA common stock (other than cancelled shares) will be entitled to look only to Dominion Energy and the surviving corporation for payment and delivery of the merger consideration, the dividend payment and the fractional shares payment due upon surrender of their SCANA stock certificates or exchange of their book-entry shares in accordance with the procedures for surrender and exchange set forth above, and Dominion Energy and the surviving corporation will remain liable (subject to applicable abandoned property, escheat or other similar law) for payment of claims for the merger consideration payable upon surrender of such SCANA stock certificates or exchange of such book-entry shares.

From and after the effective time, the stock transfer books of SCANA will be closed and there will be no transfers on the stock transfer books of SCANA of the shares of SCANA common stock that were outstanding immediately prior to the effective time of the merger.

If any SCANA stock certificate has been lost, stolen, or destroyed, upon the making of an affidavit of that fact by the person claiming such SCANA stock certificate to be lost, stolen or destroyed and, if required by the

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exchange agent or Dominion Energy, the posting by such person of a bond in a reasonable amount as indemnity against any claim that may be made against it with respect to such SCANA stock certificate, the exchange agent will pay and deliver in exchange for such SCANA stock certificate the merger consideration, the dividend payment and the fractional share payment the holder of such SCANA stock certificate is entitled to pursuant to the merger agreement.

Holders of SCANA common stock will not be entitled to receive any dividends or other distributions on Dominion Energy common stock until the merger is completed and such holders have surrendered (or are deemed to have surrendered) their SCANA common stock in exchange for Dominion Energy common stock in accordance with the instructions included with the letter of transmittal. If Dominion Energy effects any dividend or other distribution on Dominion Energy common stock with a record date after the effective time of the merger and a payment date before a SCANA shareholder surrenders (or is deemed to surrender) their SCANA common stock, such SCANA shareholder will be entitled to receive such dividend or distribution, without interest, with respect to the shares of Dominion Energy common stock to be issued to such SCANA shareholder promptly after the proper surrender (or deemed surrender) of such SCANA shareholder's SCANA common stock. If Dominion Energy effects any dividend or other distribution on Dominion Energy common stock with a record date after the effective time of the merger and a payment date after the date a SCANA shareholder surrenders (or is deemed to surrender) their SCANA common stock, such SCANA shareholder will be entitled to receive such dividend or distribution, without interest, with respect to the shares of Dominion Energy common stock that were issued to such SCANA shareholder on the appropriate payment date.

Dominion Energy and the surviving corporation will be entitled to deduct and withhold any applicable taxes from the consideration otherwise payable pursuant to the merger agreement to any holder of shares of SCANA common stock, performance share awards and restricted stock units, and pay over such withheld amount to the appropriate governmental entity. Any amount so withheld will be promptly remitted to the applicable governmental entity and be treated for all purposes under the merger agreement as having been paid to the person in respect of whom such deduction and withholding was made.

The merger consideration and any other payments to be made to SCANA shareholders pursuant to the merger agreement will be adjusted to reflect the effect of any reclassification, stock split (including a reverse stock split), stock dividend or distribution, recapitalization, exchange or readjustment of shares, merger, issuer tender or exchange offer, or other similar transaction with respect to the shares of either Dominion Energy common stock or SCANA common stock that occurs between the date of the merger agreement and the effective time of the merger to provide the SCANA shareholders and the holders of performance share awards and restricted stock units the same economic effect as provided under the merger agreement before such change.

Conditions to Completion of the Merger

The obligation of SCANA, Dominion Energy and Merger Sub to effect the merger is subject to the satisfaction or waiver of the following mutual conditions:

- the receipt of the SCANA requisite vote, which we refer to as the shareholder vote condition;
- the absence of any law, executive order, ruling, judgment, injunction or other order, which we refer to as an order, issued by any federal, state, local, or non-United States government, any court or tribunal of competent jurisdiction, any administrative, regulatory (including any stock exchange) or other governmental or quasi-governmental agency, commission, branch or authority or other governmental entity or body, which we refer to as a governmental entity (except such reference does not include Santee Cooper in its capacity as a commercial counterparty of SCE&G in connection with the NND project), that is in effect and restrains, enjoins, prevents or otherwise prohibits the completion of the merger or makes the completion of the merger illegal, which we refer to as the governmental order condition;
- the issuance of an order from the FERC authorizing the merger under Section 203 of the FPA;

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- the expiration or early termination of certain waiting periods under the HSR Act and the related rules and regulations, which provide that certain acquisition transactions may not be completed until required information has been furnished to the DOJ and the FTC;
- the issuance of an order from the NRC (x) consenting to the indirect transfer of control of NRC License No. NPF-93, Docket No. 52-027 and NRC License No. NPF-94, Docket No. 52-028 (to the extent that either (a) the NRC has not already approved the termination or withdrawal of such licenses or (b) such licenses have not already been transferred to a third party pursuant to an NRC approval) and (y) consenting to the indirect transfer of control of NRC License No. NPF-126, Docket No. 50-395, in each case from SCANA to Dominion Energy, as required by Section 184 of the Atomic Energy Act and the NRC's implementing regulations in 10 CFR 50.80;
- the issuance by the NCUC of an order authorizing SCANA and Dominion Energy to engage in the business combination transaction contemplated by the merger agreement pursuant to North Carolina General Statutes, or N.C.G.S. § 62-111(a);
- the issuance of an order from the GPSC of an order approving the indirect change of ownership of SEMI from SCANA to Dominion Energy pursuant to Official Code of Georgia Annotated, or O.C.G.A. § 46-4-25, this condition and the previous four (4) bullet points we refer to collectively as the regulatory approval conditions;
- the issuance by the SCPSC of an order approving the SCPSC petition (other than the request to make the SCPSC merger determination), unless otherwise consented to by Dominion Energy in its sole discretion, without any (i) material changes to the proposed terms, conditions or undertakings set forth in the cost recovery plan or (ii) significant changes to the economic value of the proposed terms of the cost recovery plan, in each case as reasonably determined by Dominion Energy in good faith, which we refer to as the SCPSC condition;
- the approval for listing on the NYSE of the shares of Dominion Energy common stock to be issued in connection with the transactions contemplated by the merger agreement, subject to official notice of issuance; and
- the effectiveness under the Securities Act of the registration statement on Form S-4 of which this proxy statement/prospectus is a part, and there not having been any stop order suspending the effectiveness of such Form S-4 issued or any proceedings for that purpose, which we refer to as the Form S-4 condition.

The obligation of Dominion Energy and Merger Sub to effect the merger is subject to the satisfaction or waiver of the following additional conditions:

- the representations and warranties of SCANA relating to SCANA's capitalization being true and correct in all respects, except for de minimis inaccuracies, as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date);
- the representations and warranties of SCANA relating to (i) SCANA's authority to execute and deliver the merger agreement and perform its obligations under the merger agreement and (ii) broker's and advisor's fees and commissions owed by SCANA to brokers or other financial advisor(s) in connection with the merger, each being true and correct in all material respects (disregarding all qualifications or limitations as to materiality and words of similar import set forth therein) as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date);

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- the representations and warranties of SCANA relating to (i) the absence of any changes since January 1, 2017 that has or would be reasonably expected to have, individually or in the aggregate, a material adverse effect on SCANA and its subsidiaries, taken as a whole (which is described in "*The Merger Agreement—Material Adverse Effect*") and (ii) the SCANA requisite vote being the only vote of the SCANA shareholders required to approve the merger proposal, each being true and correct in all respects as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date);
- each of the representations and warranties of SCANA other than those referred to in the immediately preceding three bullets being true and correct in all respects (disregarding all qualifications or limitations as to materiality and words of similar import set forth therein) as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date), except where the failure of such representations and warranties to be true and correct has not had or would not be reasonably expected to have, individually or in the aggregate, a material adverse effect on SCANA and its subsidiaries, taken as a whole, which (collectively with the immediately preceding three bullets) we refer to as the SCANA representation condition;
- performance by SCANA in all material respects of all obligations required to be performed by it under the merger agreement on or prior to the closing date, which we refer to as the SCANA covenant condition;
- Dominion Energy having received a certificate of the chief executive officer or the chief financial officer of SCANA, certifying that the SCANA representation condition and the SCANA covenant condition have been satisfied;
- the absence of any regulatory approval or other approval or consent, in each case in connection with the merger, or order of a governmental entity related to any of the foregoing imposing or requiring any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions, or any structural or remedial actions, that constitute a burdensome condition (which is described in "*The Merger Agreement—Reasonable Best Efforts to Obtain Regulatory Approvals*" and which we refer to as the burdensome condition closing condition);
- the absence of any changes since the date of the merger agreement that have or would be reasonably expected to have, individually or in the aggregate, a material adverse effect on SCANA and its subsidiaries, taken as a whole, which we refer to as the MAE condition;
- the absence of any order enacted by a governmental entity of competent jurisdiction or any change in law, in each case which imposes any condition that would reasonably be expected to result in (i) a material change to the proposed terms, conditions, or undertakings set forth in the SCPSC petition or (ii) a significant change to the economic value of the proposed terms set forth in the SCPSC petition, in each case as reasonably determined by Dominion Energy in good faith, which we refer to as the change in SCPSC petition condition;
- the SCPSC shall have made the SCPSC merger determination; and
- since the date of the merger agreement, there shall not have occurred any (i) substantive change in applicable law or any order with respect to the BLRA, as in effect on the date of the merger agreement, which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries or (ii) substantive change in any applicable law or any order with respect to any other laws

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of the state of South Carolina governing public utilities as contained in Title 58 of the Code of Laws of South Carolina, as in effect on the date of the merger agreement which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries, which changes we refer to collectively as SC law changes and which condition we refer to as the absence of changes in law condition.

The obligation of SCANA to effect the merger is subject to the satisfaction or waiver of the following additional conditions:

- the representations and warranties of Dominion Energy and Merger Sub relating to Dominion Energy's and Merger Sub's capitalization being true and correct in all respects, except for *de minimis* inaccuracies, as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date);
- the representations and warranties of Dominion Energy and Merger Sub relating to (i) their authority to execute and deliver the merger agreement and perform their respective obligations under the merger agreement and (ii) broker's and advisor's fees and commissions owed by Dominion Energy to brokers or other financial advisor(s) in connection with the merger, each being true and correct in all material respects (disregarding all qualifications or limitations as to materiality and words of similar import set forth therein) as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date);
- the representations and warranties of Dominion Energy and Merger Sub relating to (i) the absence of any changes since January 1, 2017 that has or would be reasonably expected to have, individually or in the aggregate, a material adverse effect on Dominion Energy and its subsidiaries, taken as a whole (which is described in "*The Merger Agreement—Material Adverse Effect*") and (ii) the approval of the merger agreement by the sole shareholder of Merger Sub being the only vote or consent of any class of capital stock of Dominion Energy or any of its affiliates necessary for Dominion Energy and Merger Sub to approve the merger agreement and complete the merger and the other transactions contemplated by the merger agreement, each being true and correct in all respects as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date);
- each of the representations and warranties of Dominion Energy and Merger Sub other than those referred to in the immediately preceding three bullets being true and correct in all respects (disregarding all qualifications or limitations as to materiality and words of similar import set forth therein) as of the date of the merger agreement and as of the closing date of the merger as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of the merger agreement), in which case such representation or warranty shall be true and correct only as of such specified date), except where the failure of such representations and warranties to be true and correct has not had or would not be reasonably expected to have, individually or in the aggregate, a material adverse effect on Dominion Energy and its subsidiaries, taken as a whole, which (collectively with the immediately preceding three bullets) we refer to as the Dominion Energy representation condition;
- performance by Dominion Energy and Merger Sub in all material respects of all obligations required to be performed by them under the merger agreement on or prior to the closing date, which we refer to as the Dominion Energy covenant condition; and

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- SCANA having received a certificate of the chief executive officer or the chief financial officer of Dominion Energy, certifying that the Dominion Energy representation condition and the Dominion Energy covenant condition have been satisfied.

We cannot be certain when, or if, the conditions to the merger will be satisfied or waived, or that the merger will be completed.

Actions to Obtain Required Shareholder Vote

Subject to the fiduciary duties of the SCANA board, under applicable law, SCANA has agreed to take, in accordance with applicable law and SCANA's organizational documents, all action necessary to call, give notice of, convene and hold the special meeting as promptly as practicable after the Form S-4 (of which this proxy statement/prospectus is a part) is declared effective under the Securities Act. The merger agreement requires the SCANA board to recommend approval of the merger proposal and take all lawful action to solicit and obtain the SCANA requisite vote unless the SCANA board changes its recommendation in accordance with the terms of the merger agreement (see the section entitled "*The Merger Agreement—Non-Solicitation of Alternative Proposals*" on page 95 of this proxy statement/prospectus). SCANA may, but is not required to, adjourn or postpone the special meeting (i) to the extent necessary to ensure that any necessary supplement or amendment to this proxy statement/prospectus is provided to the SCANA shareholders a reasonable amount of time in advance of the vote on the approval of the merger proposal, (ii) if SCANA reasonably believes it is necessary and advisable to do so in order to solicit additional proxies in order to obtain the SCANA requisite vote, (iii) if, as of the time for which the special meeting is originally scheduled, there are insufficient shares of SCANA common stock represented (either in person or by proxy) to constitute a quorum necessary to conduct the business of the special meeting or (iv) as required by law.

Reasonable Best Efforts to Obtain Regulatory Approvals

Dominion Energy, SCANA and Merger Sub are required under the terms of the merger agreement to (and shall cause their respective subsidiaries to) cooperate and use their respective reasonable best efforts to (i) promptly make any required submissions and filings under applicable law or to governmental entities with respect to the merger and the other transactions contemplated by the merger agreement, (ii) promptly furnish information requested in connection with such submissions and filings to such governmental entities or under such applicable law, (iii) keep the other parties reasonably informed with respect to the status of any such submissions and filings to such governmental entities or under such applicable law, (iv) obtain all consents and permits from any governmental entity or any other person necessary to consummate the transactions contemplated by the merger agreement as soon as practicable and (v) take or cause to be taken all other actions, and do or cause to be done all other things, reasonably necessary to consummate and make effective the merger and the other transactions contemplated by the merger agreement as soon as practicable.

Under the merger agreement, SCANA and Dominion Energy also agreed to use their respective reasonable best efforts to take or cause to be taken all actions consistent with the terms of the merger agreement and the SCPSC petition to obtain the SCPSC's approval of the SCPSC petition as soon as practicable. The material terms of the SCPSC petition agreed to by the parties in the merger agreement include, among other things (i) an aggregate up-front, one-time rate credit totaling $1.3 billion to all customers who are current customers of SCE&G at the effective time of the merger, (ii) a write down of approximately $1.4 billion by SCE&G of its investment in construction work in the NND project, (iii) SCE&G not seeking recovery of approximately $320 million in regulatory assets, (iv) a total estimated reduction of 5% in retail electric customer bills by Dominion Energy and SCE&G resulting from a $575 million refund underwritten by Dominion Energy for amounts previously collected in connection with the NND project and from the impact of federal tax reform passed in December of 2017, (v) an approximately $180 million capital investment in the Columbia Energy Center, a natural gas-fired power plant located in Gaston, South Carolina, will be excluded from rate base and rate recovery, with only certain ongoing costs to be recovered in future base and fuel rates, (vi) a finding by the
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SCPSC that approximately $3.3 billion of invested capital for the NND project is prudent and may be amortized over a 20-year period (without offset or disallowance) and recovered through retail rates, (vii) a ruling by the SCPSC that until the balance of the $3.3 billion is fully recovered, the capital costs of the unrecovered balance shall be reflected in retail rates at a return on common equity of 10.25%, a weighted average cost of debt of 5.85%, and a capital structure consisting of 52.81% equity and 47.19% debt, with these percentages fixed over the 20-year amortization period and (viii) apart from the 5% customer bill reduction mentioned above, that retail electric base rates will remain frozen at current levels until January 1, 2021, except for rate adjustments for fuel and environmental costs, demand side management costs and other rates routinely adjusted on an annual or biannual basis.

Subject to the limitations set forth in the merger agreement and as further described below, Dominion Energy, SCANA and Merger Sub have agreed to promptly take any and all steps necessary to avoid, eliminate or resolve each and every impediment to and obtain all consents under applicable laws that may be required by any governmental entity (including any regulatory clearances with respect to the transactions contemplated by the merger agreement and the SCPSC's approval of the SCPSC petition), so as to enable the parties to consummate the merger and the other transactions contemplated by the merger agreement as soon as practicable, including taking any remedial action (as described in the paragraph that immediately follows). However, any remedial action may, at the discretion of SCANA or Dominion Energy, be conditioned upon completion of the transactions contemplated by the merger agreement.

The merger agreement provides that a "remedial action" means, with respect to Dominion Energy, SCANA and each of their respective subsidiaries, committing to and effecting, by consent decree, hold separate orders, trust, or otherwise, (i) selling, licensing, holding separate or otherwise disposing of assets or businesses of Dominion Energy or SCANA or any of their respective subsidiaries, (ii) terminating, relinquishing, modifying, or waiving existing relationships, ventures, contractual rights, obligations or other arrangements of Dominion Energy or SCANA or any of their respective subsidiaries and (iii) creating any relationships, ventures, contractual rights, obligations or other arrangements of Dominion Energy or SCANA or any of their respective subsidiaries.

Subject to the limitations set forth in the merger agreement, Dominion Energy has agreed to use reasonable best efforts to take or cause to be taken any and all action, including a remedial action, to avoid or resolve as promptly as practicable any legal proceeding challenging any of the transactions contemplated by the merger agreement that seeks, or would reasonably be expected to seek, to prevent, materially impede or materially delay the consummation of such transactions. Dominion Energy, SCANA and Merger Sub have agreed to cooperate with each other and use their respective reasonable best efforts to contest, defend and resist any such proceeding and to have any order that is in effect lifted that prohibits, prevents, delays, interferes with or restricts the completion of the transactions contemplated by the merger agreement as promptly as practicable.

In connection with obtaining any consent, permit or regulatory approval as described in the above paragraphs, Dominion Energy and its affiliates are not required to, and SCANA and its subsidiaries are not required to (unless conditioned on the completion of the merger) and are not permitted to (without Dominion Energy's prior written consent), offer or accept, or agree, commit to agree or consent to, any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions (including remedial actions) that constitutes a burdensome condition (as described in the immediately following paragraph).

The merger agreement provides that a "burdensome condition" means any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions (including remedial actions) that, in the aggregate, would have or would reasonably be expected to have, a material adverse effect on the business, financial condition, assets, liabilities or results of operations of SCANA and its subsidiaries or of Dominion Energy and its subsidiaries, in each case taken as a whole. However, for purposes of determining whether a burdensome condition exists, Dominion Energy and its subsidiaries will be deemed to be a consolidated group of entities of the size and scale of a hypothetical company that is one hundred percent (100%) of the size and scale of SCANA and its

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subsidiaries, taken as a whole as of immediately prior to the effective time of the merger. Notwithstanding the foregoing, any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions relating to implementing, or otherwise arising or resulting from or imposed by, the social commitments (as described below), or any relief or other matters contemplated by the SCPSC petition or the SCPSC's approval of the SCPSC petition, shall not constitute or be taken into account in determining whether a burdensome condition exists.

Under the terms of the merger agreement, none of Dominion Energy and its affiliates are required to, and none of SCANA and its affiliates are required to (unless conditioned on the completion of the merger) and are not permitted to (without Dominion Energy's prior written consent), offer or accept, or agree, or commit to agree or consent to, any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions (including remedial actions) that (i) materially change the proposed terms, conditions or undertakings set forth in the SCPSC petition or (ii) significantly change the economic value of the proposed terms set forth in the SCPSC petition, in each case as reasonably determined by Dominion Energy in good faith.

Unless otherwise agreed to by Dominion Energy and SCANA, Dominion Energy, SCANA and/or certain SCANA subsidiaries (as applicable) are required to (i) file the SCPSC petition by January 12, 2018, (ii) file the notification and report form pursuant to the HSR Act within 15 business days after the date the merger agreement is signed, (iii) file an application for FERC approval within 40 business days after the date of the merger agreement, (iv) file an application for NRC approval within 20 business days after the date of the merger agreement, (v) file applications for FCC approvals no later than 90 business days prior to the anticipated closing date of the merger, (vi) file an application for NCUC approval within 15 business days after the date of the merger agreement and (vii) file an application for GPSC approval within 15 business days after the date of the merger agreement.

In furtherance of the foregoing, Dominion Energy, SCANA and/or certain SCANA subsidiaries (as applicable) (i) filed the SCPSC petition on January 12, 2018, (ii) filed an application for GPSC approval on January 19, 2018, (iii) filed an application for NCUC approval on January 24, 2018, and (iv) filed applications for NRC approvals on January 25, 2018. Additionally, each of Dominion Energy and SCANA filed a Notification and Report form pursuant to the HSR Act on January 19, 2018.

On February 1, 2018, the FTC notified Dominion Energy and SCANA that it had granted early termination of the HSR Act waiting period.

Dominion Energy, SCANA and Merger Sub have agreed to, subject to applicable law relating to the exchange of information:

- promptly notify the other parties of (and if in writing, furnish the other parties with copies of) any communication to such person from any third party (other than a representative of any of the parties to the merger agreement or any of their respective subsidiaries) or any governmental entity regarding the filings and submissions made in connection with the transactions contemplated by the merger agreement and permit the other parties to review and discuss in advance (and to consider in good faith any comments made by the others in relation to) any proposed written response to any communication from any third party (other than a representative of any of the parties to the merger agreement or any of their respective subsidiaries) or any governmental entity regarding such filings and submissions;
- keep the other parties reasonably informed of any developments, meetings or discussions with any third party (other than a representative of any of the parties to the merger agreement or any of their respective subsidiaries) or any governmental entity in respect of any filings, submissions, investigations, or inquiries concerning the transactions contemplated by this agreement; and
- not independently participate in any meeting or discussion with any third party (other than a representative of any of the parties to the merger agreement or any of their respective subsidiaries) or

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any governmental entity in respect of any filings, submissions, investigations or inquiries concerning the transactions contemplated by the merger agreement without giving the other party or parties to the merger agreement prior notice of such meeting or discussions to the extent it is reasonably practical to do so and, unless prohibited by such third party or governmental entity or otherwise not reasonably practical, the opportunity to attend or participate.

Notwithstanding the obligations described in the three (3) immediately preceding bullets, Dominion Energy, SCANA and Merger Sub are (i) permitted to redact any correspondence, filing, submission or communication prior to furnishing it to the other parties to the extent it contains competitively or commercially sensitive information and (ii) not prohibited from independently participating in meetings and discussions with third parties or governmental entities that solely relate to an explanation of the terms of this agreement.

SCANA and its subsidiaries are required, to the extent reasonably practicable, subject to applicable law relating to the exchange of information and except as would be in violation of, or result in a waiver or loss of, the attorney-client privilege or work-product doctrine, to do the following with respect to any material claim, hearing, investigation or proceeding, whether criminal or civil in nature, relating to or arising out of the NND project or the bankruptcy of Westinghouse.

- within 48 hours of receipt, notify Dominion Energy of (and if in writing, furnish Dominion Energy with copies of) any material communication to SCANA or its subsidiaries from any governmental entity related to or arising out of such claim, hearing, investigation or proceeding and permit Dominion Energy to review and discuss in advance (and consider in good faith any comments made by Dominion Energy in relation to) any proposed written response to any material communication from any governmental entity related to or arising out of any such claim, hearing, investigation or proceeding;
- keep Dominion Energy reasonably informed of any developments, meetings or discussions with any governmental entity related to or arising out of such claim, hearing, investigation or proceeding; and
- use good faith efforts to give Dominion Energy notice (which notice shall be prior notice to the extent providing prior notice is reasonably practical) of any material meetings or discussions relating to or arising out of such claim, hearing, investigation or proceeding (and consider in good faith any comments or guidance from Dominion Energy in relation to such meeting or discussions) and, if appropriate in SCANA's reasonable judgment, provide Dominion Energy the opportunity to attend or participate in such meetings or discussions.

Non-Solicitation of Alternative Proposals

The merger agreement provides that neither SCANA nor any of its subsidiaries nor any of their respective directors or officers will, and SCANA will instruct and use its reasonable best efforts to cause its and its subsidiaries' employees, investment bankers, attorneys, accountants and other advisors or representatives, which we refer to as representatives, not to, directly or indirectly:

- initiate, solicit or knowingly encourage any acquisition proposal (which is described in the following paragraph) or the making or any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to an acquisition proposal;
- engage in, continue or otherwise participate in any discussions or negotiations regarding any inquiry, indication of interest, proposal or offer that constitutes or could reasonably be expected to lead to, an acquisition proposal;
- furnish or provide any information or data to any third party in connection with any inquiry, indication of interest, proposal or offer that constitutes or could reasonably be expected to lead to, an acquisition proposal; or
- otherwise knowingly facilitate any effort or attempt with respect to any of the actions contemplated by the three (3) immediately preceding bullets.

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The merger agreement provides that an "acquisition proposal" means any bona fide proposal or offer from any third party or group of third parties (other than Dominion Energy, Merger Sub or any of their respective affiliates) relating to (i) any acquisition or purchase directly or indirectly, in a single transaction or series of transactions, of a business that constitutes more than fifteen percent (15%) of the net revenues, net income or consolidated assets of SCANA and its subsidiaries, taken as a whole, or more than fifteen percent (15%) of the total voting power of the equity securities of SCANA, (ii) any tender offer or exchange offer that if completed would result in any third party beneficially owning more than fifteen percent (15%) of the total voting power of the equity securities of SCANA or (iii) any merger, reorganization, consolidation, share exchange, business combination, recapitalization, liquidation, joint venture, partnership, dissolution or similar transaction involving directly or indirectly, in a single transaction or series of transactions, SCANA (or any subsidiaries of SCANA whose business constitutes more than fifteen percent (15%) of the net revenues, net income or consolidated assets of SCANA and its subsidiaries, taken as a whole).

In addition, the merger agreement requires SCANA and its subsidiaries and their respective directors, officers and employees to, and SCANA will instruct and use its reasonable best efforts to cause its and its subsidiaries' representatives to, immediately (i) cease and terminate any solicitation, discussions, negotiations or knowing facilitation or encouragement with any third party that may be ongoing with respect to any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an acquisition proposal, (ii) terminate any such third party's access to any physical or electronic data rooms and (iii) request that any such third party promptly return or destroy all confidential information concerning SCANA and its subsidiaries previously furnished to such third party by or on behalf of SCANA or any of its subsidiaries, and destroy all analyses and other materials prepared by or on behalf of such third party that contain, reflect or analyze such information, in each case, to the extent required by, and in accordance with the terms of the applicable confidentiality agreement between SCANA and such third party.

Notwithstanding the restrictions described above, prior to the time the SCANA requisite vote is obtained, the SCANA board will be permitted to (i) furnish or provide information (including non-public information or data) regarding, and provide access to, the business, properties, assets, books, records and personnel of, SCANA and its subsidiaries, to a third party making an unsolicited bona fide written acquisition proposal (and shall as promptly as is reasonably practicable make available to Dominion Energy any non-public information concerning SCANA or its subsidiaries that is provided to any such third party pursuant to this clause (i) to the extent not previously made available to Dominion Energy) and (ii) engage in discussions and negotiations with such third party with respect to such acquisition proposal, *provided* that the SCANA board has determined in good faith, (a) after consultation with SCANA's financial advisors and outside legal counsel, that such acquisition proposal is, or could reasonably be expected to lead to, a superior proposal (which is described in the following paragraph) and (b) after consultation with SCANA's outside legal counsel, that failure to take such action would reasonably be expected to be inconsistent with the SCANA board's fiduciary duties under applicable law. Furthermore, such acquisition proposal must be unsolicited, bona fide and in writing and must not have resulted from a breach of the non-solicitation restrictions described above. Before SCANA is permitted to take any of the actions described in clauses (i) or (ii) of this paragraph, the third party making such acquisition proposal is required to enter into a confidentiality agreement, which we refer to as an acceptable confidentiality agreement, having provisions with respect to the confidential treatment of SCANA's information that are not materially less favorable to those contained in the confidentiality agreement executed by Dominion Energy and SCANA on October 8, 2017 (as may be amended from time to time).

The merger agreement provides that a "superior proposal" means any unsolicited bona fide written acquisition proposal relating to any direct or indirect acquisition or purchase of (i) assets that generate more than fifty percent (50%) of the consolidated total revenues or operating income of SCANA and its subsidiaries, taken as a whole, (ii) assets that constitute more than fifty percent (50%) of the consolidated total assets of SCANA and its subsidiaries, taken as a whole or (iii) more than fifty percent (50%) of the total voting power of the equity securities of SCANA, in each case, that the SCANA board determines in good faith after consultation with SCANA's financial advisors and outside legal counsel is more favorable to the SCANA shareholders than the

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merger, taking into account the third party making the acquisition proposal and all legal, financial and regulatory aspects of the acquisition proposal (including the likelihood that such acquisition proposal would be completed in accordance with its terms) and all other relevant circumstances.

The merger agreement also requires that SCANA promptly (but in any event within forty-eight (48) hours) notify Dominion Energy in writing of the receipt of any acquisition proposal or any inquiry or offer that could reasonably be expected to lead to an acquisition proposal, indicating the identity of the third party making such proposal and the material terms and conditions of such proposal or inquiry and providing Dominion Energy with the most current version (if any) of such inquiry or proposal.

The merger agreement also requires that SCANA promptly (but in any event within forty-eight (48) hours) notify Dominion Energy in writing of the receipt of any acquisition proposal or any inquiry or offer that could reasonably be expected to lead to an acquisition proposal, indicating the identity of the third party making such proposal and the material terms and conditions of such proposal or inquiry and providing Dominion Energy with the most current version (if any) of such inquiry or proposal. With respect to any such acquisition proposal, SCANA must keep Dominion Energy reasonably informed, on a prompt basis (but in any event within forty-eight (48) hours) of any changes or modifications to the terms of such acquisition proposal and any communications between SCANA and such third party with respect to any changes or modifications to the terms of any such acquisition proposal.

Except as required by law, SCANA may not terminate, amend, modify, waive or fail to enforce any standstill provisions or similar obligation with respect to any class of equity securities of SCANA or any of its subsidiaries.

Change in SCANA Board Recommendation

The merger agreement requires that, subject to certain exceptions described below, the SCANA board (and each committee thereof) will not (i) withdraw, change, qualify, withhold or modify, or propose to do any of the foregoing, in a manner adverse to Dominion Energy or Merger Sub, the SCANA board recommendation, (ii) adopt, approve or recommend, or propose to adopt, approve or recommend, any acquisition proposal, (iii) fail to recommend against any acquisition proposal subject to Regulation 14D promulgated under the Exchange Act in any solicitation or recommendation statement made on Schedule 14D-9 within ten (10) business days after Dominion Energy requests in writing, (iv) if an acquisition proposal or any material modification thereof is made public or sent to the SCANA shareholders, fail to issue a press release that reaffirms the SCANA board recommendation within ten (10) business days after Dominion Energy requests in writing or (v) agree or resolve to take any action set forth in the foregoing clauses (i) though (iv), which we collectively refer to as a SCANA board adverse recommendation change. The SCANA board may not, subject to certain exceptions described below, authorize, cause or permit SCANA or any of its affiliates to enter into any letter of intent, memorandum of understanding, agreement in principle, definitive agreement or other similar commitment that would reasonably be expected to lead to an acquisition proposal (other than an acceptable confidentiality agreement), which we refer to as an alternative acquisition agreement.

Notwithstanding the general restrictions described above, at any time prior to obtaining the SCANA requisite vote, the SCANA board may make a SCANA board adverse recommendation change under two (2) circumstances:

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- the SCANA board (or a duly authorized committee thereof) determines that an acquisition proposal that was not received in violation of the non-solicitation provisions of the merger agreement constitutes a superior proposal and further determines in good faith, and after consultation with SCANA’s outside legal counsel, that the failure to make a SCANA board adverse recommendation change in response to the receipt of such superior proposal would reasonably be expected to be inconsistent with its fiduciary duties under applicable law; or

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- an intervening event (which is described in the following paragraph) occurs and in response thereto the SCANA board determines in good faith, after consultation with SCANA's outside legal counsel, that the failure to take such action would reasonably be expected to be inconsistent with its fiduciary duties under applicable law.

The merger agreement provides that an "intervening event" means any material event, development or change in circumstances that materially affects the business, assets or operations of SCANA and its subsidiaries, taken as a whole, that first becomes known to the SCANA board or certain officers of SCANA after the date of the merger agreement but before the SCANA requisite vote is obtained, to the extent that such event, development or change in circumstances was not reasonably foreseeable as of or prior to the date of the merger agreement or which would not reasonably be expected to have become known after reasonable investigation or inquiry as of or prior to the date of the merger agreement; *provided*, *however*, that in no event will (i) the receipt, existence or terms of an acquisition proposal or any matter relating thereto or consequence thereof, (ii) any action taken by the parties pursuant to or in compliance with the merger agreement, including any action taken in connection with seeking any regulatory approvals, (iii) any changes in law or the settlement of any lawsuits or proceedings, (iv) changes in the market price or trading volume of SCANA shares or Dominion Energy shares, or SCANA or Dominion Energy or any of their respective subsidiaries meeting or exceeding internal or published projections, forecasts or revenue or earnings predictions for any period, (v) changes in the energy markets or industry or to rates, or (vi) any event, development or change relating solely to Dominion Energy or its affiliates, in each case, constitute an "intervening event" or be taken into account in determining whether an intervening event has occurred or would reasonably be expected to result.

In each of the two circumstances described above, to make a SCANA board adverse recommendation change (and, solely with respect to a superior proposal, terminate the merger agreement to enter into an alternative acquisition agreement in accordance with the merger agreement), (i) SCANA must provide Dominion Energy with prior written notice of its intent to make such SCANA board adverse recommendation change (or, solely with respect to a superior proposal, terminate the merger agreement) at least four (4) business days prior to the SCANA board taking such action, which notice shall specify the basis for such SCANA board adverse recommendation change (or termination) and include the most current draft of any letter of intent, memorandum of understanding, agreement in principle, definitive agreement or other similar commitment that would reasonably be expected to lead to an acquisition proposal (we refer to such agreement or commitment as an alternative acquisition agreement) and any other material documents with respect to the superior proposal, if applicable, (ii) during such four (4) business day period, if requested by Dominion Energy, SCANA must make its representatives reasonably available to negotiate in good faith with Dominion Energy and its representatives regarding any modifications to the terms and conditions of the merger agreement that Dominion Energy proposes to make, and (iii) at the end of such four (4) business day period, after taking into account any modifications to the terms of the merger agreement proposed by Dominion Energy to SCANA in a written, binding and irrevocable offer, the SCANA board must determine in good faith, (a) after consultation with SCANA's outside legal counsel, that the failure to effect a SCANA board adverse recommendation change would reasonably be expected to be inconsistent with the SCANA board's fiduciary duties under applicable law and (b) in the case of a SCANA board adverse recommendation change with respect to a superior proposal, after consultation with SCANA's outside legal counsel and financial advisors, that such superior proposal still constitutes a superior proposal. In the event of a change in price or material revision or material amendment to the terms of a superior proposal, or a material change to the facts or circumstances relating to an intervening event, SCANA must deliver an additional written notice summarizing such change, revision or amendment and comply anew with the obligations described in this paragraph, except that, in the case of such a new notice, the four (4) business day period referred to above shall instead be deemed to refer to a two (2) business day period. We refer to the obligations set forth in this paragraph as the match right obligations.

Nothing contained in the merger agreement prohibits SCANA or any of its subsidiaries from (i) complying with its disclosure obligations under U.S. federal or state law, (ii) making any "stop, look or listen" communication to the SCANA shareholders pursuant to Rule 14d-9(f) promulgated under the Exchange Act (or
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any similar communications to the SCANA shareholders) or (iii) making any other disclosure to its shareholders if the SCANA board determines in good faith after consultation with SCANA's outside legal counsel that the failure to make such disclosure would be inconsistent with its fiduciary duties under applicable law.

Termination of the Merger Agreement

The merger agreement may be terminated and the merger may be abandoned at any time prior to the effective time of the merger (subject to certain exceptions and limitations described in the merger agreement), whether before or after (except as set forth below) the SCANA requisite vote is obtained:

- by mutual written consent of Dominion Energy and SCANA;
- by either Dominion Energy or SCANA:
  - if the merger has not been completed on or before the termination date, *provided*, *however*, that the termination date shall be automatically extended to April 2, 2019 if, as of the termination date, any of the governmental order condition, regulatory approval condition or the SCPSC condition has not been satisfied, *provided*, *further*, that this termination right will not be available to a party whose breach of its obligations under the merger agreement in any manner that was the principal cause of or resulted in the failure of a condition to any party's obligation to effect the merger, which termination we refer to as a termination date termination;
  - if at the special meeting (or any adjournment or postponement thereof), the SCANA requisite vote is not obtained, which termination we refer to as a SCANA "no" vote termination;
  - if any order permanently restraining, enjoining, preventing or otherwise prohibiting completion of the merger shall have become final and non-appealable, *provided*, *however*, that this termination right will not be available to a party whose breach of its obligations under the merger agreement was the principal cause of such order, which termination we refer to as a legal restraint termination;
- by SCANA:
  - if the SCANA board has effected a SCANA board adverse recommendation change with respect to a superior proposal and has approved and entered into concurrently with the termination of the merger agreement an alternative acquisition agreement with respect to such superior proposal, *provided*, *however*, that such termination will not be effective and SCANA will not be permitted to enter into an alternative acquisition agreement unless (i) SCANA complied with the match right obligations, and (ii) SCANA has paid Dominion the SCANA termination fee (which is described in "*The Merger Agreement—Termination Fees*"); *provided*, *further*, that this termination right will not be available after the SCANA requisite vote shall have been obtained, which termination we refer to as a superior proposal termination;
  - if Dominion Energy or Merger Sub have breached any of their respective representations or warranties or failed to perform any of their respective covenants under the merger agreement and such breach or failure to perform (i) would give rise to the failure of the applicable conditions to SCANA's obligation to complete the merger and (ii) cannot be cured by Dominion Energy or Merger Sub by the termination date, or if capable of being cured, is not cured prior to the earlier of (a) the thirtieth (30th) day after written notice thereof is given by SCANA to Dominion Energy and (b) the third (3rd) business day immediately preceding the termination date, *provided*, *however*, that SCANA will not have this termination right if SCANA is then in material breach of the merger agreement, which termination we refer to as a Dominion Energy breach termination;
- by Dominion Energy:
  - if the SCANA board (or a committee thereof) has effected a SCANA board adverse recommendation change, except that this termination right will not be available after the SCANA

requisite vote shall have been obtained, which termination we refer to as a change of recommendation termination; or

- if SCANA has breached any of its representations or warranties or failed to perform any of its covenants under the merger agreement and such breach or failure to perform (i) would give rise to the failure of the applicable conditions to Dominion Energy's and Merger Sub's obligation to complete the merger and (ii) cannot be cured by SCANA by the termination date, or if capable of being cured, is not cured prior to the earlier of (a) the thirtieth (30th) day after written notice thereof is given by Dominion Energy to SCANA and (b) the third (3rd) business day immediately preceding the termination date, except that Dominion Energy will not have this termination right if either Dominion Energy or Merger Sub is then in material breach of the merger agreement, which termination we refer to as a SCANA breach termination.

Termination Fees

SCANA will be required to pay Dominion Energy a termination fee equal to $240,000,000 (which we refer to as the SCANA termination fee) if:

- SCANA effects a superior proposal termination;
- (i) Dominion Energy or SCANA effects a termination date termination or a SCANA "no" vote termination or Dominion Energy effects a SCANA breach termination, (ii) a bona fide acquisition proposal has been publicly announced or publicly disclosed and has not been withdrawn (a) in the case of a termination date termination or a SCANA breach termination, prior to the date of such termination, and (b) in the case of a SCANA "no" vote termination, prior to the special meeting, and (iii) thereafter during the twelve-month period immediately following such termination, (a) SCANA enters into an alternative acquisition agreement or (b) an acquisition proposal is completed (except that for the purpose of determining whether SCANA will be required to pay the SCANA termination fee under these circumstances, the references to "fifteen percent (15%)" in the definition of acquisition proposal in the merger agreement shall be deemed to be references to "fifty percent (50%)"); or
- Dominion Energy effects a change of recommendation termination.

Dominion Energy will be required to pay SCANA a termination fee equal to $280,000,000 (which we refer to as the Dominion Energy termination fee) if:

- Dominion Energy or SCANA effects a termination date termination and, at the time of such termination, (i) the burdensome condition closing condition shall not have been satisfied or waived with respect to a regulatory approval or consent in connection with the merger (other than in connection with South Carolina regulatory approvals), (ii) (a) the governmental order condition, (b) the regulatory approval condition and (c) the SCPSC condition shall each have been satisfied or waived (unless such condition was not satisfied solely due to the proposal of a burdensome condition to which Dominion Energy did not agree) and (iii) each of (a) the shareholder vote condition, (b) the Form S-4 condition, (c) the SCANA representation condition, (d) the SCANA covenant condition and (e) the MAE condition, in each case has been satisfied or waived (except for any such conditions that have not been satisfied as a result of a breach by Dominion Energy or Merger Sub of any of their respective obligations under the merger agreement);
- Dominion Energy or SCANA effects a legal restraint termination and, at the time of such termination, (i) the burdensome condition closing condition shall not have been satisfied or waived with respect to a regulatory approval or consent in connection with the merger (other than in connection with South Carolina regulatory approvals), (ii) (a) the governmental order condition, (b) regulatory approval condition and (c) the SCPSC condition shall each have been satisfied or waived (unless such condition was not satisfied solely due to the proposal of a burdensome condition to which Dominion Energy did not agree) and (iii) each of (a) the shareholder vote condition, (b) the Form S-4 condition, (c) the

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SCANA representation condition, (d) the SCANA covenant condition and (e) the MAE condition, in each case has been satisfied or waived (except for any such conditions that have not been satisfied as a result of a breach by Dominion Energy or Merger Sub of any of their respective obligations under the merger agreement); or

- SCANA effects a Dominion Energy breach termination due to a material breach by Dominion Energy or Merger Sub of their respective obligations to obtain the regulatory approvals and consents in connection with the merger (which are described in "*The Merger Agreement —Reasonable Best Efforts to Obtain Regulatory Approvals*"), which breach has caused the failure of any of the following conditions to completion of the merger from being satisfied: (i) the governmental order condition, (ii) the regulatory approvals condition, (iii) the SCPSC condition, (iv) absence of a burdensome condition, (v) the change in SCPSC petition condition, (vi) the SCPSC merger determination and (vii) the absence of changes in law condition.

In the event the merger agreement is terminated under circumstances in which SCANA is required to pay the SCANA termination fee or Dominion Energy is required to pay the Dominion Energy termination fee and such termination fee, as applicable, is paid, the payment of such termination fee will be the sole and exclusive remedy of Dominion Energy and Merger Sub against SCANA, or of SCANA against Dominion Energy and Merger Sub, as applicable.

Conduct of Business

Under the merger agreement, each of SCANA and Dominion Energy has agreed to restrict the conduct of its respective business between the date of the merger agreement and the earlier of the effective time of the merger and the termination of the merger agreement.

In general, SCANA has agreed to, and to cause each of its subsidiaries to, conduct its business in all material respects in the ordinary course consistent with past practice and to use commercially reasonable efforts to preserve substantially intact its current business organizations, maintain adequate and comparable insurance coverage, and preserve its relationships with its employees, counterparties, customers and suppliers and governmental entities with jurisdiction over SCANA and any of its subsidiaries.

In addition, between the date of the merger agreement and the effective time of the merger, SCANA has agreed to various specific restrictions relating to the conduct of its business and the business of its subsidiaries, including restrictions on the following (in each case, subject to Dominion Energy's prior written consent, certain exceptions specified in the merger agreement, the related SCANA disclosure materials, which we refer to as the SCANA disclosure letter, or as may be required by applicable law or by a governmental entity):

- declaring or paying dividends or other distributions (other than regular quarterly cash dividends payable in respect of SCANA common stock, not in excess of a certain amount);
- splitting, combining, subdividing or reclassifying any of its capital stock or issuing any other securities in respect of, in lieu of or in substitution for shares of its capital stock;
- purchasing, redeeming or otherwise acquiring any of its or its subsidiaries' capital stock or securities convertible into or exchangeable or exercisable for any such shares of capital stock;
- issuing, selling, pledging, disposing or encumbering shares of its capital stock;
- amending its articles of incorporation or bylaws or the comparable organizational documents of any of its subsidiaries;
- acquiring (whether by merger, consolidation, purchase of property or assets or otherwise) any corporation, partnership or other business organization or any material assets or interests in any third party with a value in excess of fifty million dollars ($50,000,000) in the aggregate;

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- selling, licensing, transferring, abandoning or otherwise disposing of any of its properties, rights or assets which are material to SCANA or its subsidiaries taken as a whole or have a value in excess of twenty five million dollars ($25,000,000);
- incurring indebtedness except for (i) borrowings under existing revolving credit facilities (or replacements thereof on comparable terms, including in regards to maturity) or commercial paper programs in the ordinary course of business, (ii) incurring indebtedness in the ordinary course of business (including interest rate swaps on customary commercial terms consistent with past practice) not in excess of two hundred million dollars ($200,000,000), (iii) redeeming, prepaying, defeasing, cancelling or modifying any indebtedness in the ordinary course of business (including interest rate swaps on customary commercial terms consistent with past practice) not to exceed two hundred million dollars ($200,000,000), (iv) incurring, redeeming, prepaying, defeasing, canceling or modifying any indebtedness among SCANA or any of its subsidiaries, (v) incurring any indebtedness to replace, renew, extend, refinance or refund any existing indebtedness in the same principal amount and upon the maturity of such existing indebtedness and to the extent such existing indebtedness is indebtedness of SCANA, on terms that can be redeemed or prepaid at any time upon payment of the outstanding principal amount plus accrued interest without any make whole or similar prepayment penalty and (vi) providing guarantees and other credit support by SCANA with respect to obligations of any of its subsidiaries; *provided*, *however*, that no such indebtedness shall contain any term that would accelerate the payment thereof or require its immediate repayment due to the transactions contemplated by the merger agreement;
- settling any claim, investigation or proceeding with a governmental entity or third party, in each case, threatened, made or pending against SCANA or any of its subsidiaries which provides injunctive relief which is material to SCANA or any of its subsidiaries or requires payment in excess of ten million dollars ($10,000,000) in the aggregate, other than the settlement of any claims, investigations or proceedings made in the ordinary course of business or for an amount (excluding any amounts covered by insurance) not in excess of the amount reflected or reserved therefor in the most recent financial statements of SCANA; *provided*, *however*, that neither SCANA nor any of its subsidiaries are permitted to settle any claim, investigation or proceeding relating to or arising out of (i) the construction (or cessation of the construction), abandonment or disposal of the NND project, (ii) the bankruptcy of Westinghouse (including the settlement agreement entered into with Toshiba Corporation and any contract relating to the proceeds thereof), or (iii) any other aspect of the abandoned NND project (other than (a) the termination of any contract related to the abandoned NND project, so long as such termination results in no additional liability of SCANA or any of its subsidiaries in excess of five million dollars ($5,000,000) in the aggregate, (b) any immaterial amendment of any contract related to the abandoned NND project and (c) after prior notice to Dominion Energy, settling any mechanic liens related to the cessation of construction of the abandoned NND project);
- making capital expenditures in any fiscal year, except for (i) capital expenditures made in accordance with the capital expenditure plans included in the SCANA disclosure letter in an amount not to exceed fifty million dollars ($50,000,000) in excess of the amounts set forth in such plans during any calendar year, (ii) capital expenditures related to operational emergencies, equipment failures or outages or expenditures that SCANA reasonably determines are then necessary to maintain the safety and integrity of any asset or property in response to any unanticipated or unforeseen and subsequently discovered events, occurrences or developments or (iii) as required by law or a governmental entity;
- except as required by any SCANA benefit plan or other written agreement in effect on the date of the merger agreement, (i) granting any director or officer any increase in compensation or pay, or award any bonuses or incentive compensation, including in the case of any SCANA officer, any changes associated with promotions or other position changes, regardless of whether such promotions or changes were previously announced, (ii) granting to any current or former director, officer or employee any increase in severance, retention or termination pay, (iii) granting or amending any equity awards,

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(iv) entering into any new, or modifying any existing, employment or consulting agreement with any current or former director or officer or individual consultant pursuant to which the annual base salary of such individual exceeds two hundred fifty thousand dollars ($250,000) or the term of which exceeds twelve months, (v) establishing or amending in any material respect any material collective bargaining agreement or material benefit plan, (vi) taking any action to accelerate any rights or benefits under any benefit plan, or (vii) hiring or promoting any new officer (other than any officer whose hiring or promotion has been publicly announced, but that has not yet taken effect as of the date of the merger agreement); *provided*, *however*, that, other than as set forth in subclause (i), the foregoing shall not restrict SCANA or its subsidiaries from entering into or making available to newly hired employees or to employees in the context of promotions based on job performance or workplace requirements, in each case, in the ordinary course of business, plans, agreements, benefits and compensation arrangements that have a value that is consistent with its past practice of making compensation and benefits available to newly hired or promoted employees in similar positions under similar circumstances;

- changing its accounting methods, principles or practices, where such changes would reasonably be expected to be material to SCANA and its subsidiaries, taken as a whole (other than as required by GAAP);
- (i) making, changing or rescinding any material tax election, any tax accounting period or adopting or changing any material method of tax accounting, (ii) settling any material tax liability or consenting to any material claim or assessment or obtaining any material ruling related to taxes, (iii) filing any amended material tax return or (iv) entering into any material closing agreement relating to taxes;
- materially amending, modifying, terminating or waiving any material rights under any contract (i) required to be filed by SCANA as a "material contract" pursuant to Item 601(b)(10) of Regulation S-K under the Securities Act, (ii) that provides for indebtedness of SCANA or any of its subsidiaries of more than fifty million dollars ($50,000,000), (iii) that resulted in expenditures, receipts, liabilities, or payments by SCANA or any of its subsidiaries of more than eighty million dollars ($80,000,000) in the 2016 fiscal year or 2017 fiscal year or (iv) that requires SCANA or any of its subsidiaries to incur indebtedness or liabilities, or to make payments or expenditures of more than eighty million dollars ($80,000,000) in any one future fiscal year (in the case of clauses (ii) and (iii), excluding (a) contracts that can be terminated for convenience on less than ninety (90) days' notice without material payment or material penalty and (b) any contracts for the supply of natural gas capacity or commodity) (we refer to such contracts as SCANA material contracts), or entering into any contract that if entered into prior to the date of the merger agreement, would have been deemed a SCANA material contract;
- adopting or entering into a plan of complete or partial liquidation, dissolution, merger (other than the merger), consolidation, restructuring, recapitalization or other reorganization;
- materially changing or entering into any IT systems or cyber-security contracts that are material to SCANA and its subsidiaries; and
- authorizing, agreeing or committing to take any of the foregoing actions.

Other Covenants and Agreements

The merger agreement contains certain additional covenants and agreements between Dominion Energy and SCANA relating to the following matters, among other things:

- cooperation between Dominion Energy and SCANA in preparation of the Form S-4 (of which this proxy statement/prospectus is a part);
- the delivery of certain comfort letters and tax representation letters by Dominion Energy and SCANA for use in connection with the Form S-4 (of which this proxy statement/prospectus is a part);

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- cooperation between Dominion Energy and SCANA to obtain all governmental approvals, consents and waiting period expirations required to complete the merger;
- providing prompt notice to the other parties of any communications received from any governmental entity with respect to the merger or the other transactions contemplated by the merger agreement;
- promptly taking all steps necessary to avoid, eliminate or resolve each and every impediment to and obtain all consents under applicable law that may be required by any governmental entity so as to enable the parties to contemplate the merger and the other transactions contemplated by the merger agreement as soon as practicable;
- SCANA providing Dominion Energy with notice of any material communication to SCANA or its subsidiaries from any governmental entity related to or arising out of any material claim, investigation or proceeding related to or arising out of the construction or cessation of the construction of the NND project or the bankruptcy of Westinghouse (including the settlement agreement entered into with Toshiba Corporation and any contract relating to the proceeds thereof) and permitting Dominion Energy to, in certain circumstances, review and discuss in advance any response to such communications or participate in any meetings or discussions related thereto;
- confidentiality and access by each party to certain information about the other party and its subsidiaries prior to the effective time of the merger;
- Dominion Energy's use of reasonable best efforts to cause Dominion Energy common stock to be issued in connection with the merger to be approved for listing on the NYSE, subject to official notice of issuance, prior to the closing date;
- making certain public announcements concerning the merger;
- using reasonable best efforts to take all actions as are necessary to eliminate or minimize the effects of any anti-takeover statutes that may become applicable to the merger; and
- SCANA providing Dominion Energy with prompt written notice of any proceeding brought by a SCANA shareholder or any other third party against SCANA or its directors or officers arising out of or relating to the merger agreement or the transactions contemplated by the merger agreement and requesting Dominion Energy's consent prior to settling any such proceeding.

Social Commitments

Dominion Energy confirms in the merger agreement that, subject to the occurrence of the effective time of the merger, it:

- intends to maintain SCE&G's corporate headquarters in Cayce, South Carolina;
- will make a good faith commitment to give SCANA's employees and the employees of SCANA's subsidiaries due and fair consideration for other employment and promotion opportunities within Dominion Energy's larger organization, both inside and outside of South Carolina, to the extent any employment positions are re-aligned, reduced or eliminated in the future as a result of the merger;
- intends that the Dominion Energy board will take all necessary action as soon as practical after the effective time of the merger to appoint a current member of the SCANA Board or SCANA's executive management that is mutually agreement to Dominion Energy and SCANA as a director to serve on the Dominion Energy board; and
- intends to increase SCANA's historic level of corporate contributions to charities identified by SCANA's leadership by $1,000,000.00 per year for at least five (5) years after the effective time of the merger and to maintain or increase historic levels of community involvement, low income funding and economic development efforts in SCANA's current operating area, each of this commitment and the previous three bullets we refer to as the social commitments.

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Indemnification and Insurance

The merger agreement provides that from and after the effective time of the merger, Dominion Energy will indemnify and hold harmless each current and former director and officer of SCANA and its subsidiaries (in each case, when acting in such capacity) for any liabilities for acts or omissions occurring at or prior to the effective time of the merger including any acts or omissions occurring in respect of the transactions contemplated by the merger agreement.

In addition, from and after the effective time of the merger, Dominion Energy will cause the surviving corporation to honor the provisions regarding exculpation of directors, limitation of liability of directors and officers, advancement of expenses and indemnification set forth in the organizational documents of SCANA and its subsidiaries (as in effect on the date of the merger agreement) or certain indemnification contacts existing immediately prior to the effective time of the merger and will not, for a period of three (3) years following the effective time of the merger (as may be extended in certain instances), amended, replace or otherwise modify such provisions.

Dominion Energy is also required to cause the surviving corporation to maintain directors' and officers' and fiduciary liability insurance policies for at least six (6) years following the effective time of the merger, subject to certain limitations on the amount of premiums payable under such policies. In lieu of such insurance, SCANA may, prior to the completion of the merger, purchase a "tail" directors' and officers' liability insurance policy for its current and former directors and officers who are currently covered by the liability insurance coverage currently maintained by SCANA.

Employee Matters

The merger agreement provides that, for the period that begins at the effective time of the merger and ends on December 31, 2019 (which we refer to as the continuation period), Dominion Energy shall, or shall cause the surviving corporation to provide, each SCANA non-union employee who is employed immediately prior to the effective time of the merger with (i) annual base compensation that is no less than the annual base compensation provided to the employee immediately prior to the effective time; (ii) annual target cash incentive opportunities that are no less than the annual target cash incentive opportunities provided to the employee immediately prior to the effective time of the merger, subject to satisfaction of performance criteria determined by Dominion Energy (consistent with the form and terms and conditions, including performance criteria, of such awards provided to other similarly situated employees of Dominion Energy, and other terms and conditions of Dominion Energy's annual incentive program); (iii) long-term target incentive award opportunities that are no less than the long-term target incentive award opportunities provided to the employee immediately prior to the effective time of the merger (to be provided in such a form, and subject to performance and vesting criteria and other terms and conditions as Dominion Energy shall determine, consistent with the form and terms and conditions, including performance criteria, of such awards provided to other similarly situated employees of Dominion Energy); (iv) employment within a fifty (50)-mile radius from each employee's location of employment immediately prior to the effective time and duties and responsibilities similar to what the employee had immediately prior to the effective time of the merger; and (v) other employee benefits that are substantially comparable in the aggregate to the employee benefits provided to the employee immediately prior to the effective time of the merger. Dominion Energy shall, or shall cause the surviving corporation to provide, each SCANA union employee who is employed immediately prior to the effective time of the merger with compensation and benefits and other terms and conditions of employment in accordance with the terms of their collective bargaining agreement or any subsequently adopted collective bargaining agreement.

The merger agreement further provides that, during the continuation period, SCANA employees who are covered under two (2) SCANA severance plans for executives and other key employees in effect prior to the effective time of the merger will be provided with severance benefits no less favorable than the benefits provided under those plans for at least the longer of the continuation period or the change in control protection period

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under those plans. Benefits provided under the SCANA Corporation Supplementary Key Executive Severance Benefits Plan, including potential increases in benefits to be provided to certain executives, are described in more detail in "*The Merger—Interests of SCANA's Directors and Executive Officers in the Merger—Payments under the Supplementary Key Executive Severance Benefits Plan*." All other SCANA employees who are terminated without good cause during the continuation period will be provided with reasonable outplacement services and severance benefits that are no less favorable than the greater of (i) the severance pay that would be owed pursuant to Dominion Energy's severance program in effect as of the date of the merger agreement (notwithstanding any coverage exclusion that would otherwise apply with respect to union employees) or (ii) the employee's base salary or base compensation paid on a payroll period by payroll period basis until December 31, 2019.

The merger agreement provides that, during the continuation period or, if later, until all obligations have been satisfied, Dominion Energy will (or will cause the surviving corporation to) assume, honor and continue all of SCANA's employment, severance, retention, termination, deferred compensation, and change in control plans, policies, programs, agreements and arrangements maintained by SCANA as in effect at the effective time of the merger, including with respect to any payments, benefits or rights arising as a result of the transaction, and will not amend or terminate them unless permitted under their terms as in effect at the effective time of the merger or as required by applicable laws; provided that Dominion Energy will not amend certain deferred compensation and severance plans during the continuation period other than as required by applicable laws. Dominion Energy will also (or will cause the surviving corporation to) expressly assume and agree to perform all obligations under the terms of such plans, to the extent required by their terms.

The merger agreement also provides that each SCANA employee's service with SCANA and its subsidiaries and predecessors (to the extent such predecessor service was recognized under the comparable SCANA plan) will be treated as service with Dominion Energy and its subsidiaries for eligibility, vesting and level-of-benefit purposes (other than benefit accrual under any defined benefit pension plan or except as would result in a duplication of benefits) under any employee benefit plans maintained by Dominion Energy or its subsidiaries in which SCANA employees are eligible to participate after the closing date of the merger, including vacation, paid time off and severance plans. In addition, Dominion Energy will (or will cause the surviving corporation to) waive any pre-existing condition limitations, exclusions, actively-at-work requirements and waiting periods under any welfare benefit plan maintained by Dominion Energy, the surviving corporation or its subsidiaries in which SCANA employees and their eligible dependents will be eligible to participate from and after the effective time of the merger, except to the extent not satisfied or waived under the comparable SCANA plan immediately prior to the effective time of the merger. Dominion Energy will (or will cause the surviving corporation to) recognize the dollar amount of all co-payments, deductibles and similar expenses incurred by each SCANA employee (and his or her eligible dependents) during the calendar year or plan year in which the effective time of the merger occurs for purposes of satisfying such year's deductible and co-payment limitations under the relevant welfare benefit plans in which they are eligible to participate after the effective time of the merger. For any insured plan, such waivers and crediting of amounts will be subject to the consent of the insurer, which Dominion Energy will use commercially reasonable efforts to obtain.

Representations and Warranties

Mutual Representations and Warranties

The merger agreement contains certain customary representations and warranties by SCANA and Dominion Energy and Merger Sub that are subject, in some cases, to specific exceptions and qualifications contained in the merger agreement, in any form, statement, certification, report or other document filed with or furnished to the SEC since January 1, 2016 and publicly available at least twenty-four (24) hours prior to the date of the merger agreement (excluding, in each case, any disclosures set forth in any risk factor section or in any other section to the extent such disclosures are forward-looking statements or are cautionary, predictive or forward-looking in nature), or in the SCANA disclosure letter and the Dominion Energy disclosure materials (with any item disclosed in any section or subsection of either of the disclosure letters deemed disclosed with respect to any other section or subsection of the merger agreement to which the relevance of such item is reasonably apparent).

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These representations and warranties relate to, among other things:

- organization, good standing and corporate power;
- subsidiaries;
- capital structure;
- corporate authority and approval related to the execution, delivery and performance of the merger agreement;
- the absence of violations of, or conflicts with, either SCANA's or Dominion Energy's, or their respective subsidiaries', governing documents, or governmental orders, applicable law and certain agreements, in each case as a result of entering into and performing under the merger agreement;
- governmental filings, notices, declarations, registrations, consents, approvals or authorizations required to complete the merger;
- proper and accurate filings with the SEC since June 30, 2016;
- accuracy of financial statements;
- absence of undisclosed liabilities and certain off-balance-sheet arrangements;
- compliance with disclosure controls and procedures required under the Exchange Act;
- since January 1, 2017, the absence of any changes, developments, circumstances, effects, events or occurrences that would be expected to have a material adverse effect on SCANA or Dominion Energy and their respective subsidiaries as applicable;
- since January 1, 2017, SCANA or Dominion Energy, as applicable, have conducted their respective businesses in all material respects in the ordinary course of business consistent with past practice;
- absence of certain litigation;
- compliance with applicable laws;
- certain tax matters;
- regulatory status and compliance matters;
- broker's and finder's fees payable in connection with the merger; and
- accuracy of information supplied for the Form S-4 (of which this proxy statement/prospectus is a part).

Dominion Energy Additional Representations and Warranties

The merger agreement also contains additional representations and warranties by Dominion Energy relating to the following:

- that no vote or consent of Dominion Energy's shareholders or of any of Dominion Energy's affiliates' shareholders, other than the approval of the sole shareholder of Merger Sub, is necessary for Dominion Energy and Merger Sub to approve the merger agreement and complete the merger and the other transactions contemplated by the merger agreement;
- capitalization and operations of Merger Sub;
- the ownership of SCANA shares by Dominion Energy, Merger Sub or any of their subsidiaries; and
- available funds and financial ability to pay all amounts due in respect of the equity award consideration.

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SCANA Additional Representations and Warranties

The merger agreement also contains additional representations and warranties by SCANA relating to the following:

- the voting requirements of the SCANA shareholders in order for SCANA to approve the merger agreement and approve and complete the merger and the other transactions contemplated by the merger agreement;
- compliance with applicable permits;
- employee benefits;
- labor and employment matters;
- material contracts;
- real property;
- environmental matters;
- intellectual property, privacy and information technology matters;
- certain regulatory compliance matters relating to SCANA's existing nuclear operations, including decommissioning thereof, and the construction and abandonment of the NND project;
- takeover statutes;
- insurance policies; and
- receipt by the SCANA board of opinions from SCANA's financial advisors.

Material Adverse Effect

Many of SCANA's and Dominion Energy's representations and warranties in the merger agreement are qualified by, among other things, exceptions relating to the absence of a "material adverse effect," which means any change that has a material adverse effect on the business, financial condition, assets, liabilities or results of operations of, as applicable, SCANA and its subsidiaries, taken as a whole, or Dominion Energy and its subsidiaries, taken as a whole, except that no change arising out of or resulting from any of the following will, either alone or in combination, constitute or contribute to a material adverse effect:

- changes in the economy in the United States or elsewhere in the world, including as a result of changes in geopolitical conditions;
- changes that affect any of the industries in which SCANA and its subsidiaries or Dominion Energy and its subsidiaries, as applicable, operate;
- changes in the financial, debt, capital, credit or securities markets generally in the United States or elsewhere in the world, including changes in interest rates;
- changes in the stock price or trading volume of shares of SCANA's common stock or shares of Dominion Energy's common stock, as applicable, or credit rating of SCANA or any of its subsidiaries or Dominion Energy or any of its subsidiaries, as applicable, or any failure by SCANA or Dominion Energy, as applicable, to meet published analyst estimates or expectations of such party's revenue, earnings or other financial performance or results of operations for any period, or any failure by SCANA or Dominion Energy, as applicable, to meet its internal or published projections, budgets, plans or forecasts of its revenues, earnings or other financial performance or results of operations for any period, except that the changes underlying any such change or failure that are not otherwise excluded from the definition of material adverse effect may be considered in determining whether there has been a material adverse effect;

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- changes in any applicable law, legislative or political conditions or policy or practices of any governmental entity (other than SC law changes);
- changes in applicable accounting regulations or principles or interpretations thereof;
- an act of terrorism or an outbreak or escalation of hostilities or war (whether declared or not declared) or earthquakes, any weather-related or other force majeure events or other natural disasters or any national or international calamity or crisis;
- the announcement, execution or delivery of the merger agreement or the public announcement or pendency of the merger or the other transactions contemplated by the merger agreement, in each case, including any impact thereof on relationships, contractual or otherwise, with governmental entities or customers, suppliers, distributors, lenders, partners or employees of SCANA and its subsidiaries or Dominion Energy and its subsidiaries, as applicable;
- actions taken or requirements imposed by any governmental entities, in connection with obtaining the regulatory approvals or the SCPSC petition approval;
- any proceeding brought by a SCANA shareholder or any other person against SCANA or its directors arising out of or relating to the merger agreement or the transactions contemplated by the merger agreement or changes with respect thereto; and
- any proceeding disclosed in certain portions of the SCANA disclosure letter or changes with respect thereto;

except, with respect to the first (1st), second (2nd), third (3rd), fifth (5th) and sixth (6th) bullets above, in the case of changes, to the extent not otherwise excluded under the merger agreement, that such change has a materially disproportionate adverse effect, as applicable, on SCANA and its subsidiaries, taken as a whole, or Dominion Energy and its subsidiaries, take as a whole, as compared to the other companies engaged in the relevant business affected by such change.

Amendment

At any time prior to the effective time of the merger, the merger agreement may be amended by the parties; however, no amendment of the merger agreement will be made which, pursuant to applicable law or the rules of the NYSE, requires further approval by the SCANA shareholders or approval by the Dominion Energy shareholders, as applicable, without such approval being obtained.

Extension; Waiver

At any time prior to the effective time of the merger any party to the merger agreement may, subject to certain exceptions and limitations, (i) extend the time for performance of any obligations or other acts of the other parties, (ii) waive any inaccuracies in the representations and warranties of the other parties contained in the merger agreement or in any document delivered pursuant to the merger agreement or (iii) waive compliance by another party with any of the agreements or conditions contained in the merger agreement; provided, however, that neither Dominion Energy nor Merger Sub may perform any of the foregoing with respect to Merger Sub or Dominion Energy, respectively. No extension or waiver will be made which, pursuant to applicable law or the rules of the NYSE, requires further approval by the SCANA shareholders or approval by the Dominion Energy shareholders, as applicable, without such approval being obtained.

THE SCANA BOARD RECOMMENDS THAT YOU VOTE "FOR" THE MERGER PROPOSAL.

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NON-BINDING ADVISORY VOTE ON NAMED EXECUTIVE OFFICER MERGER-RELATED COMPENSATION

As required by Section 14A of the Exchange Act and the applicable SEC rules issued thereunder, SCANA is required to submit a proposal to SCANA shareholders for a non-binding advisory vote to approve the payment of certain compensation payable to the named executive officers of SCANA that is based on or otherwise relates to the merger. This proposal, which we refer to as the merger-related compensation proposal, gives SCANA shareholders the opportunity to express their views on the compensation that SCANA's named executive officers may be entitled to receive that is based on or otherwise relates to the merger.

The compensation that SCANA's named executive officers may be entitled to receive that is based on or otherwise relates to the merger is summarized in the table entitled "*Merger-Related Compensation*," which is included in "*The Merger—Potential Payments Upon a Termination In Connection With a Change in Control*" beginning on page 76 of this proxy statement/prospectus.

The following resolution is submitted for shareholder vote:

"RESOLVED, that the shareholders of SCANA Corporation approve, on a non-binding advisory basis, the compensation that may be paid or become payable to its named executive officers that is based on or otherwise relates to the merger as disclosed pursuant to Item 402(t) of Regulation S-K in the table entitled "*Merger-Related Compensation*," which is included in "*The Merger—Potential Payments Upon a Termination In Connection With a Change in Control*," and the related narrative disclosures.

Approval of this proposal is not a condition to completion of the merger, and as a non-binding advisory vote, the result will not be binding on SCANA or Dominion Energy, or the SCANA board or the Dominion Energy board or their respective compensation committees. Therefore, if the merger is approved by the shareholders of SCANA and completed, the merger-related compensation would still be paid to the SCANA named executive officers regardless of whether the shareholders of SCANA approve the merger-related compensation proposal. Proxies submitted without direction pursuant to this solicitation will be voted "FOR" the approval of the compensation to be paid to SCANA's named executive officers that is based on or otherwise relates to the merger, as disclosed in this proxy statement/prospectus.

THE SCANA BOARD RECOMMENDS THAT YOU VOTE "FOR" THE MERGER-RELATED COMPENSATION PROPOSAL.

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PROPOSAL TO ADJOURN THE SPECIAL MEETING OF SCANA SHAREHOLDERS

If there are not sufficient votes at the time of the special meeting to approve the merger proposal, SCANA may propose to adjourn the special meeting to a later date or dates in order to permit the solicitation of additional proxies. Under South Carolina law, no notice of adjournment need be given to you other than the announcement of the adjournment at the special meeting.

In order to permit proxies that have been received by SCANA at the time of the special meeting to be voted for an adjournment, if necessary, SCANA has submitted the adjournment proposal to you as a separate matter for your consideration.

In the adjournment proposal, SCANA is asking you to authorize the holder of any proxy solicited by the SCANA board to vote in favor of adjourning the special meeting and any later adjournments. If the SCANA shareholders approve the adjournment proposal, SCANA could adjourn the special meeting, and any adjourned session of the special meeting, to use the additional time to solicit additional proxies in favor of the merger proposal, including the solicitation of proxies from shareholders that have previously voted against the merger proposal. As a result, even if proxies representing a sufficient number of votes against the merger proposal have been received such that if a vote on the merger proposal were held the merger proposal would not be approved, SCANA could adjourn the special meeting without a vote on the merger proposal and seek to convince the holders of those shares of SCANA common stock to change their votes to votes in favor of the merger proposal.

The SCANA board believes that if the number of shares of SCANA common stock present or represented at the special meeting and voting in favor of the merger proposal is insufficient to approve the merger proposal, it is in the best interests of the SCANA shareholders to enable the SCANA board, for a limited period of time, to continue to seek to obtain a sufficient number of additional votes to approve the merger proposal.

The adjournment proposal will be approved if more votes are cast in favor of the proposal than against the proposal. Abstentions and broker non-votes will not be counted as a vote “FOR” or “AGAINST” the adjournment proposal. Proxies submitted without direction pursuant to this solicitation will be voted “FOR” the approval of the adjournment proposal.

THE SCANA BOARD RECOMMENDS THAT YOU VOTE “FOR” THE ADJOURNMENT PROPOSAL.

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UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

The unaudited pro forma consolidated financial statements of Dominion Energy consist of a condensed consolidated balance sheet at September 30, 2017, consolidated statement of income for the nine months ended September 30, 2017 and consolidated statement of income for the year ended December 31, 2016, which reflect Dominion Energy's anticipated acquisition of SCANA, expected to occur by the end of 2018. The unaudited pro forma consolidated financial statements included herein have been derived from the following historical financial statements:

- the audited financial statements of Dominion Energy for the year ended December 31, 2016;
- the unaudited interim financial statements of Dominion Energy for the nine months ended September 30, 2017;
- the audited financial statements of SCANA for the year ended December 31, 2016; and
- the unaudited interim financial statements of SCANA for the nine months ended September 30, 2017.

On January 2, 2018, Dominion Energy entered into the merger agreement with SCANA, which provides for a stock-for-stock merger in which SCANA shareholders would receive 0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock. Following completion of the merger, SCANA would operate as a wholly-owned subsidiary of Dominion Energy.

The pro forma adjustments have been prepared as if the acquisition of SCANA occurred on September 30, 2017 in the case of the unaudited pro forma condensed consolidated balance sheet and on January 1, 2016 in the case of the unaudited pro forma consolidated statements of income. The unaudited pro forma consolidated financial statements should be read in conjunction with the related notes, which are included herein, the financial statements and notes included in Dominion Energy's Annual Report on Form 10-K for the year ended December 31, 2016 and the Quarterly Report on Form 10-Q for the nine months ended September 30, 2017, and the financial statements and notes included in SCANA's Annual Report on Form 10-K for the year ended December 31, 2016 and the Quarterly Report on Form 10-Q for the nine months ended September 30, 2017.

The unaudited pro forma consolidated financial statements do not necessarily reflect what Dominion Energy's financial position and results of operations would have been if it had owned SCANA during the periods presented. In addition, they are not necessarily indicative of its future results of operations or financial condition. The assumptions and adjustments give pro forma effect to events, described below, that are (i) directly attributable to Dominion Energy's acquisition of SCANA, (ii) factually supportable, and (iii) with respect to the unaudited pro forma consolidated statements of income, expected to have a continuing impact on Dominion Energy. The actual adjustments may differ from the pro forma adjustments.

The unaudited pro forma consolidated financial statements give effect to Dominion Energy's acquisition of SCANA for total consideration consisting of the right to receive 0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock. While additional financing, either through the issuance of common stock or debt, may be required by Dominion Energy to fund certain provisions proposed to the SCPSC in connection with the merger agreement, such financing transactions have not been reflected in the unaudited pro forma consolidated financial statements due to the uncertainty of such plans at this point in time.

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DOMINION ENERGY, INC.
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
AT SEPTEMBER 30, 2017

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(millions)	Dominion Energy	SCANA	Pro Forma Adjustments	Dominion Energy Pro Forma
ASSETS				
Current Assets				
Cash and cash equivalents	$ 227	$ 1,011	$ —	$ 1,238
Customer receivables	1,292	481	(6)(q)	1,767
Other receivables	212	195	—	407
Inventories	1,527	288	—	1,815
Regulatory assets	311	64	—	375
Other	425	125	—	550
Total current assets	3,994	2,164	(6)	6,152
Investments				
Nuclear decommissioning trust funds	4,881	132	—	5,013
Investment in equity method affiliates	1,895	30	—	1,925
Other	320	47	—	367
Total investments	7,096	209		7,305
Property, Plant and Equipment				
Property, plant and equipment	73,610	16,065	247 (n)	89,787
			(135)(f)	
Accumulated depreciation, depletion and amortization	(20,799)	(5,568)	135 (f)	(26,232)
Total property, plant and equipment, net	52,811	10,497	247	63,555
Deferred Charges and Other Assets				
Goodwill	6,405	210	1,398(g)	8,013
Regulatory assets	2,503	6,690	(1,536)(e)	7,657
Other	2,582	249	144(i)	2,975
Total deferred charges and other assets	11,490	7,149	6	18,645
Total assets	$ 75,391	$20,019	$ 247	$ 95,657

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DOMINION ENERGY, INC.
UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
AT SEPTEMBER 30, 2017

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(millions)	Dominion Energy	SCANA	Pro Forma Adjustments	Dominion Energy Pro Forma
LIABILITIES AND EQUITY				
Current Liabilities				
Securities due within one year	$ 2,788	$ 177	$ —	$ 2,965
Short-term debt	3,060	1,022	—	4,082
Accounts payable	757	266	59 (b)	1,076
			(6) (q)	
Accrued interest, payroll and taxes	843	635	—	1,478
Regulatory liabilities	88	15	1,295 (c)	1,536
			138 (d)	
Other	1,023	336	64 (j)	1,470
			37 (h)	
			6 (n)	
			4 (k)	
Total current liabilities	8,559	2,451	1,597	12,607
Long-Term Debt				
Long-term debt	25,529	6,455	47 (l)	32,036
			5 (l)	
Junior subordinated notes	3,980	—	—	3,980
Remarketable subordinated notes	1,377	—	—	1,377
Total Long-term debt	30,886	6,455	52	37,393
Deferred Credits and Other Liabilities				
Deferred income taxes and investment tax credits	9,379	1,767	(916)(o)	10,230
Regulatory liabilities	2,906	2,015	(1,095)(c)	4,263
			437 (d)	
Other	5,159	1,544	241 (n)	6,971
			16 (k)	
			11 (j)	
Total deferred credits and other liabilities	17,444	5,326	(1,306)	21,464
Total liabilities	56,889	14,232	343	71,464
Commitments and Contingencies				
Equity				
Common stock - no par	9,789	2,389	(2,389)(m)	16,967
			7,178 (a)	
Retained earnings	7,119	3,447	(3,447)(m)	5,632
			(1,536)(e)	
			(575)(d)	
			(200)(c)	
			(59)(b)	
			(20)(h)	
			(20)(k)	
			923 (o)	
Accumulated other comprehensive loss	(628)	(49)	49 (p)	(628)
Total common shareholders' equity	16,280	5,787	(96)	21,971
Noncontrolling interests	2,222	—	—	2,222
Total equity	18,502	5,787	(96)	24,193
Total liabilities and equity	$ 75,391	$20,019	$ 247	$ 95,657

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DOMINION ENERGY, INC.
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF INCOME
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2017

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(millions, except share amounts)	Dominion Energy	SCANA	Pro Forma Adjustments	Dominion Energy Pro Forma
Operating Revenue	$ 9,376	$ 3,249	$ 11 (j)	$ 12,590
			(46)(q)	
Operating Expenses				
Electric fuel and other energy-related purchases	1,711	508	(6)(q)	2,213
Purchased (excess) electric capacity	(8)	10	—	2
Purchased gas	441	808	(40)(q)	1,209
Other operations and maintenance	2,166	543	—	2,709
Impairment loss	—	210	—	210
Depreciation, depletion and amortization	1,421	285	24 (i)	1,730
Other taxes	519	200	—	719
Total operating expenses	6,250	2,564	(22)	8,792
Income from operations	3,126	685	(13)	3,798
Other income	249	53	—	302
Interest and related charges	905	270	(13)(l)	1,161
			(1)(l)	
Income from operations including noncontrolling interests before income tax expense	2,470	468	1	2,939
Income tax expense	683	142	— (o)	825
Net Income Including Noncontrolling Interests	1,787	326	1	2,114
Noncontrolling Interests	100	—	—	100
Net Income Attributable to Dominion Energy	$ 1,687	$ 326	$ 1	$ 2,014
Average shares of common stock outstanding-basic	633.4	142.9	(47.3)(r)	729.0
Average shares of common stock outstanding-diluted	633.4	142.9	(47.3)(r)	729.0
Earnings Per Common Share — Basic	$ 2.66	$ 2.28	—	$ 2.76
Earnings Per Common Share — Diluted	$ 2.66	$ 2.28	—	$ 2.76

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DOMINION ENERGY, INC.
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2016

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(millions, except share amounts)	Dominion Energy	SCANA	Pro Forma Adjustments	Dominion Energy Pro Forma
Operating Revenue	$ 11,737	$ 4,227	$ 64 (j) (58)(q)	$ 15,970
Operating Expenses				
Electric fuel and other energy-related purchases	2,333	627	(7)(q)	2,953
Purchased electric capacity	99	13	—	112
Purchased gas	459	1,054	(49)(q)	1,464
Other operations and maintenance	3,064	755	(2)(q)	3,817
Depreciation, depletion and amortization	1,559	371	46 (i)	1,976
Other taxes	596	254	—	850
Total operating expenses	8,110	3,074	(12)	11,172
Income from operations	3,627	1,153	18	4,798
Other income	250	55	—	305
Interest and related charges	1,010	342	(19)(l) (1)(l)	1,332
Income from operations including noncontrolling interests before income tax expense	2,867	866	38	3,771
Income tax expense	655	271	15 (o)	941
Net Income Including Noncontrolling Interests	2,212	595	23	2,830
Noncontrolling Interests	89	—	—	89
Net Income Attributable to Dominion Energy	$ 2,123	$ 595	$ 23	$ 2,741
Average shares of common stock outstanding-basic	616.4	142.9	(47.3)(r)	712.0
Average shares of common stock outstanding-diluted	617.1	142.9	(47.3)(r)	712.7
Earnings Per Common Share - Basic	$ 3.44	$ 4.16	—	$ 3.85
Earnings Per Common Share - Diluted	$ 3.44	$ 4.16	—	$ 3.85

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DOMINION ENERGY, INC.
NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. BASIS OF PRESENTATION

The unaudited pro forma consolidated financial statements included herein have been derived from the following historical financial statements:

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- the audited financial statements of Dominion Energy for the year ended December 31, 2016;
- the unaudited interim financial statements of Dominion Energy for the nine months ended September 30, 2017;
- the audited financial statements of SCANA for the year ended December 31, 2016; and
- the unaudited interim financial statements of SCANA for the nine months ended September 30, 2017.

On January 2, 2018, Dominion Energy entered into an Agreement and Plan of Merger with SCANA, which provides for a stock-for-stock merger in which SCANA shareholders would receive 0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock. Following completion of the merger, SCANA would operate as a wholly-owned subsidiary of Dominion Energy.

The pro forma adjustments have been prepared as if the acquisition of SCANA occurred on September 30, 2017 in the case of the unaudited pro forma condensed consolidated balance sheet and on January 1, 2016 in the case of the unaudited pro forma consolidated statements of income for the year ended December 31, 2016 and for the nine months ended September 30, 2017. The adjustments give pro forma effect to events that are (i) directly attributable to Dominion Energy's acquisition of SCANA, (ii) factually supportable, and (iii) with respect to the unaudited pro forma consolidated statements of income, expected to have a continuing impact on Dominion Energy. The adjustments are based on currently available information and certain estimates and assumptions, and therefore the actual effects of these transactions will differ from the pro forma adjustments. However, management believes that the assumptions used provide a reasonable basis for presenting the significant effects of the transaction, and that the pro forma adjustments in the unaudited pro forma consolidated financial statements give appropriate effect to the assumptions. The effects on the unaudited pro forma consolidated financial statements of the transaction described above are more fully described in Note 4.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies followed in preparing the unaudited pro forma consolidated financial statements are those used by Dominion Energy as set forth in the audited historical financial statements and notes of Dominion Energy included in its Annual Report on Form 10-K for the year ended December 31, 2016, as filed. The unaudited pro forma consolidated financial statements reflect any adjustments known at this time to conform SCANA's historical financial information to Dominion Energy's significant accounting policies based on Dominion Energy's review of SCANA's summary of significant accounting policies, as disclosed in the SCANA historical financial statements incorporated by reference, and preliminary discussions with SCANA's management. Upon completion of the merger and a more comprehensive comparison and assessment, additional differences may be identified.

NOTE 3. PRELIMINARY PURCHASE PRICE AND PRELIMINARY PURCHASE PRICE ALLOCATION

Preliminary Purchase Price

The merger agreement provides that each outstanding share of SCANA common stock will be converted into the right to receive 0.6690 of a share of Dominion Energy common stock.

The fair value of the purchase consideration expected to be transferred on the closing date includes the value of the estimated equity consideration (including the value attributable to the consideration transferred of

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replacement stock compensation awards). The fair value per share of Dominion Energy common stock was assumed for pro forma purposes to be $75.07 per share, which was the closing price of Dominion Energy's common stock on February 13, 2018, and may change significantly between these unaudited pro forma consolidated financial statements and the closing of the acquisition. The accompanying unaudited pro forma condensed consolidated balance sheet reflects an estimated preliminary purchase price of approximately $7.2 billion.

The preliminary purchase price for the merger is estimated as follows:

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(millions, except exchange ratio and closing price)	
SCANA shares outstanding at September 30, 2017	142.9
Exchange ratio (per SCANA share)	0.6690
Estimated total Dominion Energy common shares to be issued	95.6
Closing price of Dominion Energy common stock on February 13, 2018	75.07
Estimated equity portion of purchase price	$ 7,178
Estimated equity compensation	17
Total estimated purchase price	$ 7,195

Preliminary Purchase Price Allocation

Under the acquisition method of accounting, the identifiable assets acquired and liabilities assumed of SCANA are recorded at fair value on the acquisition date and added to those of Dominion Energy. The pro forma adjustments included herein are preliminary and based on estimates of the fair value and useful lives of the assets acquired and liabilities assumed and have been prepared to illustrate the estimated effect of the acquisition between Dominion Energy and SCANA. Significant portions of SCANA's operations are subject to the rate-setting authority of the FERC, SCPSC or NCUC. The carrying values of the assets and liabilities subject to regulatory accounting under GAAP, including property, plant and equipment, are considered to approximate the fair values. A fair value adjustment has not been included for SCANA's pension and other postretirement benefit obligations, which could vary by a significant amount due to potential changes in discount rates, return on plan assets or other assumptions surrounding the determination of these obligations. At this time, Dominion Energy management does not have sufficient information to record any adjustments to measure legal contingencies at fair value or at a reasonably estimable amount. The final purchase price allocation is dependent upon certain valuation and other studies that have not yet been completed. The final determination of the purchase price allocation, upon the consummation of the acquisition, will be based on the net assets acquired as of that date and will depend on a number of factors, which cannot be predicted with any certainty at this time. The purchase price allocation may change materially based on the receipt of more detailed information. Accordingly, the pro forma purchase price allocation is preliminary and is subject to further adjustment as additional information becomes available and as additional analyses and final valuations are completed. There can be no assurance that these additional analyses and final valuations will not result in significant changes to the estimates of fair value set forth below.

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The following table provides a summary of the preliminary allocation of the estimated purchase price to the identifiable tangible and intangible assets acquired and liabilities assumed of SCANA, based on SCANA's consolidated balance sheet at September 30, 2017, with all excess value over consideration paid recorded as goodwill.

(millions)	
Total current assets	$ 2,164
Investments	209
Property, plant and equipment	10,497
Goodwill	1,608
Regulatory assets	6,690
Other deferred charges and other assets, including intangible assets	393
Total assets	21,561
Total current liabilities	2,515
Long-term debt	6,507
Deferred tax liabilities	1,774
Regulatory liabilities	2,015
Other deferred credits and other liabilities	1,555
Total liabilities	14,366
Total estimated purchase price	$ 7,195

NOTE 4. PRO FORMA ADJUSTMENTS AND ASSUMPTIONS

The following transactions are directly attributable to Dominion Energy's acquisition of SCANA.

(a) Reflects the issuance of 95.6 million shares of Dominion Energy common stock to SCANA shareholders as consideration for the acquisition. The number of shares of Dominion Energy common stock was calculated based on 142.9 million of shares of SCANA common stock outstanding at September 30, 2017 multiplied by the 0.6690 exchange ratio per the merger agreement. Based on the closing price of Dominion Energy at February 13, 2018 of $75.07, such consideration is calculated to have a value of $7.2 billion, as shown in Note 3 above.

(b) Reflects the accrual of $59 million in estimated transaction costs associated with the acquisition of SCANA by Dominion Energy, including audit, legal and advisory fees.

(c) Reflects an up-front, one-time rate credit totaling $1.3 billion to all current retail electric service customers of SCE&G to be paid within 90 days of the closing of the merger, as proposed to the SCPSC, through the reclassification of $1.1 billion of an existing regulatory liability from noncurrent to current and the accrual of an additional $200 million to current regulatory liabilities. The impact of this up-front, one-time rate credit has not been reflected in the unaudited pro forma consolidated statements of income as the $200 million charge is nonrecurring.

(d) Reflects the accrual of a $575 million refund of amounts previously collected from retail electric customers of SCE&G to be credited over an estimated eight-year period following the merger, as proposed to the SCPSC. The allocation between current and noncurrent regulatory liabilities has been determined based on the expected portion to be credited to customer bills. The impact of this refund has not been reflected in the unaudited pro forma consolidated statements of Income as the $575 million charge is nonrecurring.

(e) Reflects the write-down of $1.5 billion of existing regulatory assets associated with the NND project which SCE&G will not seek recovery of following the merger, as proposed to the SCPSC. The impact of this write-down has not been reflected in the unaudited pro forma consolidated statements of income as the $1.5 billion charge is nonrecurring.

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(f) Reflects the presentation of nonregulated property, plant and equipment at estimated fair value and the removal of historical accumulated depreciation. For the purposes of the preliminary purchase price allocation in Note 3, the estimated fair value is equal to the carrying value.

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(g) Reflects the excess of Dominion Energy's consideration paid of approximately $1.6 billion over the amount of identifiable assets and liabilities assumed in the transaction (goodwill) as shown in Note 3 above. In addition, this reflects the removal of SCANA's previously recorded goodwill.

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(h) Reflects the estimated settlement of all outstanding SCANA equity compensation awards at the time of the merger, calculated based on an estimated share price of $50.22, which is 0.6690 percent of the share price of Dominion Energy's common stock at closing on February 13, 2018 of $75.07, and allocated between compensation considered to be service provided prior to the merger ($17 million) and expense to be recognized after the merger ($20 million). The impact of this charge has not been reflected in the unaudited pro forma consolidated statements of income as it is nonrecurring.

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(i) Reflects an intangible asset for the value of customer relationships estimated to be $144 million with a weighted average useful life of approximately three (3) years included within the preliminary purchase price allocation in Note 3. Amortization is based on the expected pattern of economic benefit, estimated to be $46 million, $31 million, $21 million, $14 million and $10 million over the five (5)-year period following the acquisition. Estimated amortization of this asset is $24 million for the nine months ended September 30, 2017 and $46 million for the year ended December 31, 2016.

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(j) Reflects a contract liability for the unfavorable terms of an existing contract estimated to be $75 million with a 14-month useful life included within the preliminary purchase price allocation in Note 3. Estimated amortization of this liability is $11 million for the nine months ended September 30, 2017 and $64 million for the year ended December 31, 2016.

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(k) Reflects an increase in current liabilities for incremental charitable contributions committed to by Dominion Energy under the terms of the merger agreement of $20 million, $4 million of which is considered a current liability. The impact of this charge has not been reflected in the unaudited pro forma consolidated statements of income as it is nonrecurring.

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(l) Reflects the fair value adjustment of long-term debt of $47 million, on a weighted average maturity of approximately three (3) years, and the write-off of $5 million of unamortized debt issuance costs included within the preliminary purchase price allocation in Note 3. Estimated amortization of the fair value premium, and the elimination of the recorded debt issuance cost amortization, is $13 million and $1 million for the nine months ended September 30, 2017, and $19 million and $1 million for the year ended December 31, 2016, respectively.

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(m) Reflects the elimination of SCANA's historical shareholders' equity.

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(n) This pro forma adjustment conforms SCANA's accounting for AROs to the methodology used by Dominion Energy. The cash flows used to measure Dominion Energy's pipeline AROs reflect the cost and timing of activities legally required to retire component sections of pipeline as they are removed from service. The cash flows previously used to measure SCANA's pipeline AROs are those legally required to retire the entire pipeline system at one point in time. As a result of this change in accounting estimate, Dominion Energy recorded an increase of $247 million to property, plant and equipment and increases of $6 million and $241 million to current and noncurrent other liabilities, respectively.

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(o) Reflects income taxes on pro forma adjustments based on an estimated statutory tax rate of 38.3%. The unaudited pro forma condensed consolidated balance sheet includes adjustments related to the preliminary purchase price allocation ($7 million) and related to pro forma adjustment impacting retained earnings ($923 million).

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(p) Reflects the elimination of SCANA's historical accumulated other comprehensive loss.

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(q) Reflects the elimination of transactions between Dominion Energy and SCANA, primarily for the purchase and sale of natural gas transportation, included in each company's historical financial statements.

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(r) Reflects the elimination of the SCANA common stock offset by the issuance of 95.6 million shares of Dominion Energy common stock as discussed in tickmark (a).

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COMPARISON OF SHAREHOLDER RIGHTS

If the merger is completed, SCANA shareholders will become shareholders of Dominion Energy. The rights of Dominion Energy shareholders are governed by and subject to the provisions of the VSCA, and the Dominion Energy charter and the Dominion Energy bylaws, rather than the provisions of the SCBCA and Title 35, Chapter 2 of the Code of Laws of South Carolina 1976, as amended, which we refer to as the Business Combination Statutes, the SCANA charter, the SCANA bylaws, and the "Governance Principles" of SCANA adopted by the SCANA board, which we refer to as the Governance Principles. The following is a summary of the material differences between the rights of holders of Dominion Energy common stock and the rights of holders of SCANA common stock. It does not purport to be a complete description of those differences, does not include a complete description of the specific rights of Dominion Energy shareholders and SCANA shareholders, and is qualified in its entirety by reference to the relevant provisions of (i) the VSCA, (ii) the SCBCA and the Business Combination Statutes, (iii) the Dominion Energy charter, (iv) the Dominion Energy bylaws, (v) the SCANA charter, (vi) the SCANA bylaws, (vii) the description of Dominion Energy common stock contained in Dominion Energy's Form 8-K/A filed on August 8, 2016, (viii) the Governance Principles and (ix) the description of SCANA common stock contained in SCANA's Registration Statement on Form 8-B dated November 6, 1984, as amended on May 26, 1995.

The identification of some of the differences in the rights of such holders as material is not intended to indicate that other differences that may be equally important do not exist. We urge you to read carefully the relevant portions of the VSCA, the SCBCA and the Business Combination Statutes, as well as the Dominion Energy charter, the Dominion Energy bylaws, the SCANA charter and the SCANA bylaws, copies of which are available, without charge, to any person, including any beneficial owner to whom this proxy statement/prospectus is delivered, by following the instructions listed under "*Where You Can Find More Information*" on page 136 of this proxy statement/prospectus.

AUTHORIZED CAPITAL STOCK

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DOMINION ENERGY	SCANA
The Dominion Energy charter authorizes it to issue one billion shares of common stock without par value and 20 million shares of preferred stock. As of , 2018, there were shares of Dominion Energy common stock outstanding and no shares of Dominion Energy preferred stock outstanding	The SCANA charter authorizes it to issue 200 million shares of common stock without par value. As of , 2018, there were [ ] shares of SCANA common stock outstanding. SCANA is not authorized to issue any preferred stock.

VOTING RIGHTS

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DOMINION ENERGY	SCANA
Each share of Dominion Energy common stock is entitled to one vote in the election of directors and other matters. Common stock shareholders are not entitled to cumulative voting rights.	Each share of SCANA common stock is entitled to one vote in the election of directors and other matters. Common stock shareholders are not entitled to cumulative voting rights.

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NUMBER OF DIRECTORS

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DOMINION ENERGY	SCANA
The Dominion Energy charter currently provides that the Dominion Energy board shall consist of not less than 10 or more than 17 directors. The exact number of directors, within the range specified in the preceding sentence, is determined from time to time by resolution adopted by (i) the affirmative vote of a majority of the directors then in office or (ii) the shareholders of Dominion Energy by a majority of the votes entitled to be cast at an election of directors. The Dominion Energy board currently has 12 directors.	The SCANA bylaws currently provide that the SCANA board shall consist of not less than nine or more than 20. The exact number of directors, within the range specified in the preceding sentence, is determined from time to time by resolution adopted by (i) the SCANA board by the affirmative vote of a majority of the directors at a meeting at which a quorum is present or (ii) the SCANA shareholders, if more votes are cast in favor of the proposed size of the board of directors than against the proposed size. The SCANA board currently has nine directors.

CLASSES OF DIRECTORS

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DOMINION ENERGY	SCANA
The Dominion Energy board is not classified. All directors are elected annually.	The SCBCA permits a classified board so long as SCANA has at least six directors, and the SCANA charter provides for a classified board. The SCANA board is divided into three classes. Each class of directors consists, as nearly as possible, of one-third of the total number of directors constituting the entire board. Each director serves for a term ending on the date of the third annual meeting of shareholders following the annual meeting at which the director was elected. However, the SCANA charter provides that the term of a director who is not a salaried employee of SCANA shall expire at the annual meeting next preceding the date on which such director attains age 70 and the term of office of any director who is a salaried employee of SCANA (except in the case of the Chief Executive Officer) shall expire upon such director attaining age 65 or upon his retirement from active service with the corporation, whichever is earlier.

ELECTION OF DIRECTORS

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DOMINION ENERGY	SCANA
Under the Dominion Energy bylaws, a director is elected if the number of votes cast for a nominee's election exceeds the number of votes cast against the nominee's election. In a contested election, where the number of nominees exceeds the number of directors to be elected, directors are elected by a plurality of the votes cast.	Under the SCBCA, directors are elected by a plurality of the votes cast by the shares entitled to vote in the election at a meeting at which a quorum is present. The Governance Principles provide that in an election in which the number of nominees is not greater than the number of board seats open for election any nominee who receives a greater number of votes "withheld" from his or her election than votes "for" his or her election will tender his or her

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DOMINION ENERGY	SCANA
	written resignation to the Chairman of the SCANA board for consideration by the Nominating and Governance Committee of the SCANA board, which we refer to as the Nominating and Governance Committee. The Nominating and Governance Committee will consider such tendered resignation and will make a recommendation to the SCANA board concerning the acceptance or rejection of such resignation. In determining its recommendation to the SCANA board, the Nominating and Governance Committee will consider all factors deemed relevant by the members of the Nominating and Governance Committee. The SCANA board will take formal action on the Nominating and Governance Committee's recommendation no later than 90 days following the date of the shareholders' meeting at which the election occurred.

REMOVAL OF DIRECTORS

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DOMINION ENERGY	SCANA
Under the Dominion Energy bylaws, directors may be removed from office for cause if the number of votes cast to remove the director constitutes a majority of the votes entitled to be cast at an election of directors of the voting group by which the director was elected.	The SCANA charter provides that the vote of at least 80% of the shares entitled to vote shall be required to remove a director except for cause. A director may be removed for cause if the number of votes cast favoring removal exceeds the number of votes cast opposing removal. Under the SCANA charter, cause for removal of a director means fraudulent or dishonest acts, or gross abuse of authority in the discharge of duties to SCANA, and must be established after written notice of specific charges and an opportunity to meet and refute such charges.

FILLING VACANCIES ON THE BOARD OF DIRECTORS

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DOMINION ENERGY	SCANA
Vacancies on the Dominion Energy board, whether occurring due to the creation of a new directorship or as a result of death, resignation, retirement or disqualification of a director, may be filled only by a majority vote of the directors then in office. If a vacancy results from the removal of a director by shareholders for cause at a meeting called for such purpose, the shareholders may elect a successor if such purpose was included in the meeting notice. Any director elected to fill a vacancy will serve until the next annual meeting of shareholders.	The SCANA charter provides that vacancies on the SCANA board, whether occurring due to the creation of a new directorship or as a result of the death, resignation, retirement, disqualification or removal of a director or otherwise, may be filled only by a majority vote of the directors then in office even if less than a quorum is present when the vote was held. Any director elected to fill a vacancy will serve until the next shareholders' meeting at which directors are elected.

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PROXY ACCESS FOR DIRECTOR NOMINATIONS

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DOMINION ENERGY	SCANA
The Dominion Energy bylaws permit a shareholder, or a group of up to 20 shareholders, owning 3% or more of Dominion Energy's outstanding common stock for at least three years, to nominate and include in the annual proxy materials director candidates to occupy up to two or 20% of the board seats (whichever is greater), provided that such shareholder or group of shareholders otherwise satisfies the requirements set forth in the bylaws.	The SCANA bylaws permit a shareholder, or a group of up to 20 shareholders, owning 3% or more of SCANA's outstanding common stock for at least three years, to nominate and include in the annual meeting proxy materials director candidates for election for up to one director or 20% of the directors to be elected (whichever is greater), provided that such shareholder or group of shareholders otherwise satisfies the requirements set forth in the bylaws.

SPECIAL MEETINGS OF SHAREHOLDERS

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DOMINION ENERGY	SCANA
Under the Dominion Energy bylaws, meetings of the shareholders may be called by the chairman of the board, the vice chairman, the president or a majority of the members of the Dominion Energy board. Special meetings of shareholders also will be held whenever called by the Corporate Secretary, upon the written request of shareholders owning more than 25% of all outstanding shares of common stock continuously for a period of at least one year prior to the date of such request.	Under the SCANA bylaws, special meetings of the shareholders may be called by the chief executive officer, by the chairman of the SCANA board or by a majority of the members of the SCANA board.

QUORUM

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DOMINION ENERGY	SCANA
The Dominion Energy bylaws provide that, at any meeting of the shareholders, a majority of the votes entitled to be cast on a matter shall constitute a quorum. A lesser interest may adjourn any meeting from time to time.	The SCBCA provides that a majority of votes entitled to be cast on a matter shall constitute a quorum. Once a share is represented for any purpose at a meeting, it is considered present for quorum purposes for the remainder of the meeting and for any adjournment of that meeting unless a new record date is or must be set for that adjourned meeting.

NOTICE OF SHAREHOLDER MEETINGS

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DOMINION ENERGY	SCANA
Under the Dominion Energy bylaws, notice stating the place, day and hour of each shareholders meeting and, in the case of a special meeting, the purpose for which the meeting is called, shall be given not less than 10 nor more than 60 days before the date of the meeting to each shareholder of record entitled to vote at the meeting. Notice of a shareholders meeting to act on an amendment of the charter, on a plan of merger or share exchange, on a proposed dissolution of Dominion Energy or on a proposed sale, lease or exchange, or other disposition of assets that would leave Dominion	Under the SCBCA, notice stating the date, time and place of each shareholders' meeting, and in the case of a special meeting, the purpose for which the meeting is called, must be given no fewer than 10 nor more than 60 days before the meeting to each shareholder of record entitled to vote at the meeting. In addition, notice of a shareholders' meeting to act on an amendment to the charter, on a plan of merger or share exchange, on a proposed dissolution of SCANA or on a proposed sale, lease, exchange or other disposition of all or substantially all of its

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DOMINION ENERGY	SCANA
Energy without a significant continuing business activity shall be given not less than 25 nor more than 60 days before the date of the meeting. If any shareholders meeting is adjourned to a different date, time or place, notice need not be given if the new date, time or place is announced at the meeting before adjournment. However, if a new record date for the adjourned meeting is fixed, notice of the adjourned meeting shall be given to shareholders entitled to notice of the new record date.	property other than in the usual and regular course of business must be given to each shareholder not entitled to vote. If any shareholders' meeting is adjourned to a different date, time or place, notice need not be given of the new date, time or place if the new date, time and place is announced at the meeting before adjournment. However, if a new record date for the adjourned meeting is or must be fixed, notice of the adjourned meeting must be given to shareholders entitled to notice as of the new record date.

ADVANCE NOTICE OF SHAREHOLDER PROPOSALS

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DOMINION ENERGY	SCANA
The Dominion Energy bylaws establish an advance notice procedure with regard to nominations and other business proposals to be brought before the annual meeting by a shareholder. To nominate directors, shareholders must submit a written notice to the Corporate Secretary at least 60 days before a scheduled meeting. The notice must include the name and address of the shareholder and of the nominee, a description of any arrangements between the shareholder and the nominee, information about the nominee required by the SEC, the written consent of the nominee to serve as a director and other information. Non-director nomination shareholder proposals must be submitted to the Corporate Secretary at least 90 days before the first anniversary of the date of the last annual meeting. The notice must include a description of the proposal, the reason for presenting the proposal at the annual meeting, the text of any resolutions to be presented, the shareholder's name and address and number of shares held and any material interest of the shareholder in the proposal.	The SCANA bylaws establish an advance notice procedure with regard to nominations and other business proposals to be brought before the annual meeting by a shareholder. To nominate a director or to propose other business, a shareholder must submit a written notice to the Corporate Secretary at least 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting. The notice must include the name, address and share ownership of the shareholder making the nomination or proposing other business. In the case of a nomination, the notice must also include the information about the nominee required by the SEC, a description of any arrangements between the shareholder and the nominee and the written consent of the nominee to serve as a director and other information. In the case of a business proposal, the notice must contain a description of the proposal, the reason for presenting the proposal at the annual meeting and any material interest of such shareholder in such business.

ACTION BY WRITTEN CONSENT OF THE SHAREHOLDERS

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DOMINION ENERGY	SCANA
Neither the Dominion Energy charter nor the Dominion Energy bylaws provide for action by written consent of the shareholders.	Under the SCBCA, action required or permitted to be taken at a shareholders' meeting may be taken without a meeting if the action is taken by all the shareholders entitled to vote on the action. The action must be evidenced by one or more written consents describing the action taken, signed by all the shareholders entitled to vote on the action, and delivered to the corporation for inclusion in the minutes or filing with the corporate records.

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"POISON PILL" PROVISIONS AND OTHER SHAREHOLDER PROTECTIVE MEASURES

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DOMINION ENERGY	SCANA
Neither the Dominion Energy charter nor the Dominion Energy bylaws establish any anti-takeover provisions or "poison pill" provisions.	The SCANA charter provides that any "business combination" involving SCANA and any "related person" or any affiliate or associate of a related person must be approved by holders of at least 80% of SCANA common stock. However, such higher vote is not required if (i) the business combination is approved by a majority of the directors who are not the related person or an affiliate or associate of the related person and who were directors immediately before the related person became a related person, (ii) the business combination is solely with a subsidiary of SCANA and does not have the effect of increasing the voting power of the related person or (iii) the business combination satisfies certain minimum price and other standards and no "extraordinary event" occurs after the related person becomes a related person and prior to the business combination, all as described in the SCANA charter. For purposes of these provisions, (1) a "related person" means any person (with certain exceptions) who is the beneficial owner of more than 10% of SCANA common stock; (2) a "business combination" means any of the following transactions, when entered into by SCANA or a subsidiary of SCANA with, or upon a proposal by or on behalf of, a related person: (a) a merger or completion of a plan of share exchange of SCANA or any subsidiary, (b) the sale, lease, mortgage, pledge, transfer or other disposition other than in the ordinary course of business of assets of SCANA or any subsidiary having an aggregate fair market value of $10 million or more, (c) the issuance or transfer by SCANA or any subsidiary of any securities of SCANA or that subsidiary, other than proportionately to all SCANA shareholders or such subsidiary, (d) the adoption of any plan or proposal for the liquidation or dissolution of SCANA, (e) a reclassification of securities, recapitalization or other transaction (whether or not involving a related person) which has the effect of increasing the voting power of a related person in the capital stock of SCANA or any subsidiary, or (f) any agreement, contract or other arrangement providing directly or indirectly for any of the foregoing; and (3) an "extraordinary event" means, as to any business combination and any related person, any of the following events that is not approved by a majority of all SCANA directors who are not related persons or affiliates, associates or representatives of related

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DOMINION ENERGY	SCANA
	persons and who were directors immediately prior to the time such related person became a related person, including but not limited to: (a) any reduction in the annual rate of dividends on SCANA common stock or failure to increase such annual rate to reflect any reclassification, recapitalization, reorganization or any similar transaction that reduces the number of outstanding shares of SCANA common stock, (b) the receipt by a related person of any direct or indirect benefit from any loans, advances, guarantees, pledges or other financial assistance or any tax credits or other tax advantages provided by SCANA or its subsidiaries, whether in anticipation of or in connection with the business combination or otherwise or (c) any increase in the number of shares of common stock that the related person owns, except in a transaction that does not increase the related person's percentage of ownership thereof. The SCANA charter also requires the approval of the holders of a majority of the outstanding shares of SCANA's common stock before SCANA may purchase any outstanding shares of its common stock from any person known by SCANA to be an owner of more than three percent of SCANA's common stock, which we refer to as a selling shareholder, who has purchased or agreed to purchase any of such shares within the most recent two-year period at a price known by SCANA to be above "market price" (unless SCANA purchases such shares on the same terms as a result of an offer by SCANA to purchase all of the outstanding shares of SCANA common stock). For purposes of the vote required to approve such transaction with a selling shareholder, the shares of SCANA common stock held by such selling shareholder shall be counted as having abstained regardless of how they have been voted. For purposes of these provisions, "market price" means the highest closing sale price, during the 30-day period immediately preceding the date in question, of a share of SCANA common stock on the composite tape for New York Stock Exchange issues.

BUSINESS COMBINATION STATUTES

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DOMINION ENERGY	SCANA
The VSCA contains several provisions relating to transactions with interested shareholders (holders of more than 10% of any class of a corporation's outstanding voting shares). Transactions between a corporation and an interested shareholder are referred to	The Business Combination Statutes contain several provisions relating to transactions with interested shareholders (holders of more than 10% of the voting power of a corporation's outstanding voting shares or any person who currently is or was within the

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DOMINION ENERGY	SCANA
as affiliated transactions. The VSCA prohibits a Virginia corporation from engaging in an affiliated transaction with an interested shareholder during the three years following the date that such shareholder becomes "interested" without (i) approval of two-thirds of the disinterested voting shares and (ii) majority approval of disinterested directors. After those initial three years, a material affiliated transactions must be approved by either (i) two-thirds of disinterested shareholders or (ii) a majority of disinterested directors. Affiliated transactions include mergers, share exchanges, material dispositions of corporate assets, dissolution or any reclassification of securities or merger of the corporation with any of its subsidiaries which has the result of increasing the percentage of voting shares owned by an interested shareholder by more than five percent. The provisions of the VSCA relating to affiliated transactions do not apply if a majority of disinterested directors approve the acquisition of shares making a person an interested shareholder, and the VSCA permits corporations to opt out of the affiliated transactions provisions. Dominion Energy has not opted out. The VSCA also contains provisions regulating certain control share acquisitions, which are transactions causing the voting strength of any person acquiring beneficial ownership of shares of a Virginia public corporation to meet or exceed certain threshold voting percentages (20%, 33 1/3%, or 50%). Shares acquired in a control share acquisition have no voting rights unless the voting rights are granted by a majority vote of all outstanding shares other than those held by the acquiring person or any officer or employee-director of the corporation. The acquiring person may require that a special meeting of the shareholders be held to consider the grant of voting rights to the shares acquired in the control share acquisition. The Dominion Energy bylaws grant Dominion Energy the right to redeem the shares purchased by an acquiring person in a control share acquisition. Dominion Energy can do this if the acquiring person fails to deliver a statement to Dominion Energy listing information required by the VSCA or if the shareholders vote not to grant voting rights to the acquiring person. The VSCA permits corporations to opt out of the control share acquisition provisions. Dominion Energy has not opted out.	two years prior to such transaction an affiliate or associate of such interested shareholder). The Business Combination Statutes prohibit a South Carolina corporation from engaging in a business combination of the type described above in the section of this chart entitled "Anti-Takeover Provisions and Other Shareholder Protections" (except that only such sales, leases, mortgages, pledges, transfers or other dispositions of assets which represent at least ten percent of the assets, earning power or net income, determined on a consolidated basis, or aggregate market value of the outstanding shares, of such corporation shall be taken into account) with an interested shareholder unless such business combination meets the requirements of the corporation's articles of incorporation and either (i) is approved by (a) such corporation's board of directors prior to the date the interested shareholder first becomes an interested shareholder ("share acquisition date"), or (b) affirmative vote of the holders of a majority of the outstanding voting shares not beneficially owned by the interested shareholder (or any affiliate or associate thereof), at a meeting called for that purpose no earlier than two years after the interested shareholder's share acquisition date, or (ii) satisfies certain minimum price and other standards described in the Business Combination Statutes. However, if such business combination occurs during the two years following the interested shareholder's share acquisition date, such business combination must also be approved by a majority of disinterested directors. For purposes of these provisions, a director of a corporation is disinterested if the director is not a present or former officer or employee of such corporation. The Business Combination Statutes permit corporations to opt out of the business combinations provisions. SCANA has not opted out. The Business Combination Statutes also contain provisions regulating certain control share acquisitions, which are transactions causing the voting strength of any person acquiring beneficial ownership of shares of a South Carolina public corporation to meet or exceed certain threshold voting percentages (20%, 33 1/3%, or 50%). Shares acquired in a control share acquisition have no voting rights unless the voting rights are granted by a majority vote of all outstanding shares other than those held by the acquiring person or any officer or employee-director of the corporation. The acquiring

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DOMINION ENERGY	SCANA
	person may require that a special meeting of the shareholders be held to consider the grant of voting rights to the shares acquired in the control share acquisition. The Business Combination Statutes permit a South Carolina corporation to redeem the shares purchased by an acquiring person in a control share acquisition if so authorized in a corporation's articles of incorporation or bylaws before a control share acquisition has occurred, and if the acquiring person fails to deliver a statement to such corporation listing information required by the Business Combination Statutes or if the shareholders vote not to grant voting rights to the acquiring person. Neither the SCANA charter nor the SCANA bylaws contain such authorizations. The Business Combination Statutes permit corporations to opt out of the control share acquisition provisions. SCANA has not opted out.

VOTES ON MERGERS, CONSOLIDATIONS AND CERTAIN OTHER TRANSACTIONS

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DOMINION ENERGY	SCANA
The Dominion Energy charter requires that any merger, share exchange or sale of substantially all of Dominion Energy's assets be approved by a majority of the votes entitled to be cast on the matter by each voting group entitled to vote on the matter. Abstentions and broker non-votes will have no effect on the outcome.	The SCBCA provides that any merger, share exchange or sale of substantially all of SCANA's assets must be approved by holders of at least two-thirds of SCANA shares outstanding. Abstentions and broker non-votes have the effect of a vote against any such proposed transaction. As described above in the sections of this chart entitled "Anti-Takeover Provisions and Other Shareholder Protections" and "Business Combination Statutes", greater or additional voting requirements may apply in certain circumstances.

DIVIDENDS

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DOMINION ENERGY	SCANA
Dominion Energy's common shareholders may receive dividends when declared by the Dominion Energy board. Dividends may be paid in cash, stock or other form. In certain cases, common shareholders may not receive dividends until Dominion Energy has satisfied its obligations to any preferred shareholders. Under certain circumstances, Dominion Energy's indentures may also restrict its ability to pay cash dividends.	Under the SCBCA, the SCANA board may authorize and SCANA may pay dividends; provided, however, that no dividend may be paid if, after giving it effect, SCANA would be insolvent. Dividends may be paid in cash, stock or other form. Under certain circumstances, indentures or other agreements entered into by certain of SCANA's subsidiaries may restrict the ability of such subsidiaries to pay dividends to SCANA.

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LIMITATION OF PERSONAL LIABILITY OF OFFICERS AND DIRECTORS

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DOMINION ENERGY	SCANA
The Dominion Energy charter provides that Dominion Energy's directors and officers will not be personally liable for monetary damages to Dominion Energy for breaches of their fiduciary duty as directors or officers, unless they violated their duty of loyalty to Dominion Energy or its shareholders, acted in bad faith, knowingly or intentionally violated the law, authorized illegal dividends or redemptions or derived an improper personal benefit from their action as directors or officers. This provision applies only to claims against directors or officers arising out of their role as directors or officers and not in any other capacity. Directors and officers remain liable for violations of the federal securities laws, and Dominion Energy retains the right to pursue legal remedies other than monetary damages, such as an injunction or rescission for breach of the officer's or director's duty of care.	The SCANA charter provides that SCANA's directors will not be personally liable for monetary damages for breaches of their fiduciary duty as directors except for (i) any breach of their duty of loyalty to SCANA or its shareholders, (ii) acts or omissions not in good faith or which involve gross negligence, intentional misconduct or a knowing violation of law, (iii) authorizing any illegal dividends or redemptions or (iv) any transaction from which the director derived improper personal benefit. This provision applies only to claims against directors arising out of their role as directors and not in any other capacity. Directors remain liable for violations of the federal securities laws, and SCANA retains the right to pursue legal remedies other than monetary damages, such as an injunction or rescission for breach of the director's duty of care.

INDEMNIFICATION OF DIRECTORS AND OFFICERS AND INSURANCE

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DOMINION ENERGY	SCANA
The Dominion Energy charter mandates indemnification of its directors and officers to the full extent permitted by the VSCA and any other applicable law. The VSCA permits a corporation to indemnify its directors and officers against liability incurred in all proceedings, including derivative proceedings, arising out of their service to the corporation or to other corporations or enterprises that the officer or director was serving at the request of the corporation, except in the case of willful misconduct or a knowing violation of a criminal law. Dominion Energy is required to indemnify its directors and officers in all such proceedings if they have not violated this standard. Dominion Energy has also entered into agreements relating to the advancement of expenses for certain of its directors and officers in advance of a final disposition of proceedings or the making of any determination of eligibility for indemnification pursuant to Dominion Energy's charter. In addition, the Dominion Energy charter limits the liability of its directors and officers to the full extent permitted by the VSCA as now and hereafter in effect. The VSCA places a limit on the liability of a director or officer in derivative or shareholder proceedings equal to the lesser of (i) the amount specified in the corporation's articles of incorporation or a shareholder-approved bylaw; or (ii) the greater of (a) $100,000 or (b) twelve months of cash compensation received by the director or	The SCBCA permits a corporation to indemnify its directors and officers against liability incurred in all proceedings if such directors and officers (i) conducted themselves in good faith, (ii) reasonably believed, in the case of conduct in their official capacities with the corporation, that their conduct was in the corporation's best interest and, in all other cases, that their conduct was at least not opposed to its best interest or, in the case of conduct with respect to an employee benefit plan, for a purpose reasonably believed to be in the interests of the participants and beneficiaries of such plan, and (iii) in the case of any criminal proceeding, had no reasonable cause to believe their conduct was unlawful; provided, however, such directors and officers may not be indemnified in connection with a proceeding in which they are adjudged liable to the corporation or any other proceeding charging that such directors or officers received any improper personal benefit in which they are adjudged liable on that basis. SCANA is also required to indemnify its directors and officers against reasonable expenses incurred by them in all proceedings to which they are party and have been adjudged to be wholly successful on the merits or otherwise. SCANA has also entered into agreements relating to the advancement of expenses for its directors and certain of its officers in advance of a final disposition of proceedings.

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DOMINION ENERGY	SCANA
officer. The limit does not apply in the event the director or officer has engaged in willful misconduct or a knowing violation of a criminal law or a federal or state securities law. The effect of the Dominion Energy charter, together with the VSCA, is to eliminate liability of directors and officers for monetary damages in derivative or shareholder proceedings so long as the required standard of conduct is met. Dominion Energy has purchased directors' and officers' liability insurance policies. Within the limits of their coverage, the policies insure (1) the directors and officers of Dominion Energy against certain losses resulting from claims against them in their capacities as directors and officers to the extent that such losses are not indemnified by Dominion Energy and (2) Dominion Energy to the extent that it indemnifies such directors and officers for losses as permitted under the laws of Virginia.	In addition, the SCANA charter eliminates or limits the liability of its directors only to the maximum extent permitted by the SCBCA or any successor law or laws, and provides that any repeal or modification of such protection by the SCANA shareholders shall not adversely affect any right or protection of a director of the corporation existing at the time of such repeal or modification. SCANA has purchased directors' and officers' liability insurance policies. Within the limits of their coverage, the policies insure (1) the directors and officers of SCANA against certain losses resulting from claims against them in their capacities as directors and officers to the extent that such losses are not indemnified by SCANA and (2) SCANA to the extent that it indemnifies such directors and officers for losses as permitted under the laws of South Carolina.

AMENDMENT TO ARTICLES OF INCORPORATION AND BYLAWS

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DOMINION ENERGY	SCANA
Generally, the Dominion Energy charter may be amended if the votes cast favoring the amendment exceed the votes cast opposing the amendment at a meeting where a quorum is present. Some provisions of the Dominion Energy charter, however, may only be amended or repealed by a majority of the votes entitled to be cast on the matter by each voting group entitled to vote on the matter. The Dominion Energy bylaws may be amended by both the Dominion Energy board and the Dominion Energy shareholders, except that a bylaw enacted by the shareholders may not be amended or repealed by the board if it so expressly provides. Furthermore, provisions of the Dominion Energy bylaws concerning special meetings of shareholders and the nomination and election of directors may not be amended or repealed without the affirmative vote of a majority of the votes entitled to be cast on the matter.	Generally, the SCANA charter may be amended if approved by holders of a majority of SCANA common stock. Some provisions of the SCANA charter, including the provisions relating to removal of directors other than for cause, certain business combinations described above in the section of this chart entitled "Anti-Takeover Provisions and Other Shareholder Protections", the classification of the board, filling board vacancies and the expiration of terms of directors who are not salaried employees of SCANA, may only be amended or repealed if approved by holders of at least 80% of SCANA common stock. SCANA bylaws may be amended by both the SCANA board and the SCANA shareholders, except that a bylaw adopted, amended or repealed by the SCANA shareholders may not be adopted, amended or repealed by the SCANA board if the shareholders expressly so provide.

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LEGAL MATTERS

The validity of the shares of Dominion Energy common stock to be issued in the merger will be passed upon by McGuireWoods LLP. Certain U.S. federal income tax consequences relating to the merger and the transactions contemplated by the merger agreement will be passed upon by Morgan, Lewis & Bockius LLP for Dominion Energy and by Mayer Brown LLP for SCANA.

EXPERTS

Dominion Energy

The consolidated financial statements incorporated in this registration statement by reference from Dominion Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2016 and the effectiveness of the Dominion Energy, Inc. and subsidiaries' internal control over financial reporting have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their reports, which are incorporated herein by reference. Such consolidated financial statements have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

SCANA

The consolidated financial statements, and the related financial statement schedule, incorporated in this registration statement by reference from SCANA Corporation's Annual Report on Form 10-K for the year ended December 31, 2016, and the effectiveness of SCANA Corporation's internal control over financial reporting as of December 31, 2016 have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their reports, which are incorporated herein by reference. Such consolidated financial statements and financial statement schedule have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

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SHAREHOLDER PROPOSALS

SCANA's 2018 annual meeting of shareholders, which we refer to as the 2018 annual meeting, is scheduled for , 2018. As disclosed in the proxy statement for SCANA's 2017 annual meeting of shareholders, any SCANA shareholder desiring to submit a proposal pursuant to Rule 14a-8 under the Exchange Act for inclusion in SCANA's proxy statement and proxy card for the 2018 annual meeting must have submitted the proposal to SCANA's Corporate Secretary no later than November 24, 2017. In addition, any shareholder desiring to bring other business (including director nominations) before the 2018 annual meeting must have provided, pursuant to the SCANA bylaws, written notice of such business to SCANA's Corporate Secretary no later than November 24, 2017. In the event that the 2018 annual meeting is scheduled to be held on a date after May 25, 2018, SCANA will announce the date by which proposals pursuant to Rule 14a-8 must be submitted. In the event that the 2018 annual meeting is scheduled to be held on a date after June 26, 2018, the time period for any SCANA shareholder to bring other business (including director nominations) pursuant to the SCANA bylaws, before the 2018 annual meeting will be extended until the later of 120 days prior to the date of the 2018 annual meeting or 10 days following the day on which the 2018 annual meeting is publicly announced.

For additional requirements, SCANA shareholders should refer to Article I, Section 5 of the SCANA bylaws, a current copy of which may be obtained from SCANA's Corporate Secretary.

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OTHER MATTERS

As of the date of this proxy statement/prospectus, the SCANA board knows of no matters that will be presented for consideration at the special meeting other than as described in this proxy statement/prospectus. If any other matters properly come before the special meeting or any adjournments or postponements of the meeting and are voted upon, the enclosed proxy will confer discretionary authority on the individuals named as proxy to vote the shares represented by the proxy as to any other matters. The individuals named as proxies intend to vote in accordance with their best judgment as to any other matters.

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WHERE YOU CAN FIND MORE INFORMATION

Dominion Energy and SCANA file annual, quarterly and current reports, proxy statements and other information with the SEC. Dominion Energy's file number with the SEC is 001-08489 and SCANA's file number with the SEC is 001-08809. Filings made with the SEC by Dominion Energy and SCANA are available to the public over the Internet at the SEC's web site at *www.sec.gov*. The information contained on the SEC's website is expressly not incorporated by reference into this proxy statement/prospectus. You may also read and copy any document Dominion Energy and SCANA file at the SEC's public reference room at 100 F. Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

Dominion Energy has filed with the SEC a registration statement on Form S-4 of which this proxy statement/prospectus forms a part. The registration statement registers the shares of Dominion Energy common stock to be issued to SCANA shareholders in connection with the merger. The registration statement, including the attached exhibits and schedules, contains additional relevant information about Dominion Energy common stock. The rules and regulations of the SEC allow Dominion Energy and SCANA to omit certain information included in the registration statement from this proxy statement/prospectus.

The SEC allows Dominion Energy and SCANA to "incorporate by reference" the information they file with it, which means that Dominion Energy and SCANA can disclose important information to you by referring you to those documents. The information incorporated by reference is considered to be part of this proxy statement/prospectus, and information that Dominion Energy and SCANA file later with the SEC will automatically update or supersede this information.

Some of the filings Dominion Energy makes with the SEC are on a combined basis with two of its subsidiaries, Virginia Power and Dominion Energy Gas. Dominion Energy's combined filings with the SEC present separate filings by each of Virginia Power, Dominion Energy Gas and Dominion Energy. Dominion Energy incorporates by reference the documents listed below (other than any portions of the documents not deemed to be filed) and any future filings made with the SEC under Sections 13(a), 13(c), 14, or 15(d) of the Exchange Act, except those portions of filings that relate to Virginia Power or Dominion Energy Gas as a separate registrant, before the date of the special meeting.

Some of the filings SCANA makes with the SEC are on a combined basis with one of its subsidiaries, SCE&G. SCANA's combined filings with the SEC present separate filings by SCE&G and SCANA. SCANA incorporates by reference the documents listed below (other than any portions of the documents not deemed to be filed) and any future filings made with the SEC under Sections 13(a), 13(c), 14, or 15(d) of the Securities Exchange Act of 1934, except those portions of filings that relate to SCE&G as a separate registrant before the date of the special meeting.

Dominion Energy:

- Annual Report on Form 10-K for the year ended December 31, 2016;
- Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017, June 30, 2017 and September 30, 2017;
- Current Reports on Form 8-K or Form 8-K/A, filed January 12, 2017, January 24, 2017, January 27, 2017, March 27, 2017, May 10, 2017, May 18, 2017, July 3, 2017, October 2, 2017, October 30, 2017, December 1, 2017, January 4, 2018, January 5, 2018, January 31, 2018, February 1, 2018 and February 14, 2018; and
- the description of Dominion Energy's common stock contained in Amendment No. 2 to its Current Report on Form 8-K, filed August 8, 2016.

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- Annual Report on Form 10-K for the year ended December 31, 2016;

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- Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017, June 30, 2017 and September 30, 2017; and

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- Current Reports on Form 8-K or Form 8-K/A, filed on January 5, 2017, April 28, 2017, July 5, 2017, July 28, 2017, August 3, 2017, September 27, 2017, November 3, 2017, December 21, 2017, December 28, 2017, January 4, 2018, January 5, 2018 and January 26, 2018.

You may request a copy of any of the documents incorporated by reference by Dominion Energy and SCANA at no cost by requesting them in writing or by telephone from the appropriate company at:

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Dominion Energy, Inc.	**SCANA Corporation**
Corporate Secretary	Bryant Potter, Investor Relations
120 Tredegar Street	220 Operation Way
Richmond, Virginia 23219	Cayce, South Carolina 29033
Email: Corporate.Secretary@dominionenergy.com	Telephone: (803) 217-6916

You may also obtain more information regarding SCANA by contacting its Internet website, at *www.scana.com* (which is not intended to be an active hyperlink). The information on SCANA's Internet website (other than the documents expressly incorporated by reference as set forth above) is not incorporated by reference in this proxy statement/prospectus, and you should not consider it part of this proxy statement/prospectus.

You may also obtain more information regarding Dominion Energy by contacting its Internet website, at *www.dominionenergy.com* (which is not intended to be an active hyperlink). The information on Dominion Energy's Internet website (other than the documents expressly incorporated by reference as set forth above) is not incorporated by reference in this proxy statement/prospectus, and you should not consider it part of this proxy statement/prospectus.

You may also obtain documents incorporated by reference into this proxy statement/prospectus by requesting them in writing or by telephone from SCANA's proxy solicitor, Georgeson, Inc., at 480 Washington Boulevard, Jersey City, NJ 07310, SCANA shareholders Call Toll-Free: [ ], Banks and Brokers Call Collect: [ ], Email: [ ] [ ] at [ ].

You should rely only on the information incorporated by reference or provided in this proxy statement/prospectus or to which this proxy statement/prospectus refers you. Neither Dominion Energy nor SCANA have authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. The information which appears in this proxy statement/prospectus and which is incorporated by reference in this proxy statement/prospectus may only be accurate as of the date of this proxy statement/prospectus or the date of the document in which incorporated information appears. The business, financial condition, results of operations and prospects may have changed for each of Dominion Energy and SCANA since that date.

If you are a SCANA shareholder and would like to request documents, please do so by , 2018 to receive them before the special meeting. If you request any documents from SCANA, SCANA will mail them to you by first class mail, or another equally prompt means, within one (1) business day after SCANA receives your request.

Notwithstanding the foregoing, information furnished by Dominion Energy or SCANA on any Current Report on Form 8-K, including the related exhibits, that, pursuant to and in accordance with the rules and regulations of the SEC, is not deemed "filed" for purposes of the Exchange Act will not be deemed to be incorporated by reference into this proxy statement/prospectus.

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Annex A

Merger Agreement

Execution Version

AGREEMENT AND PLAN OF MERGER

by and among

DOMINION ENERGY, INC.,

SEDONA CORP.

and

SCANA CORPORATION

Dated as of January 2, 2018

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AGREEMENT AND PLAN OF MERGER

This AGREEMENT AND PLAN OF MERGER, dated as of January 2, 2018 (this "Agreement"), is entered into by and among DOMINION ENERGY, INC., a Virginia corporation ("Parent"), SEDONA CORP., a South Carolina corporation and a wholly-owned Subsidiary of Parent ("Merger Sub") and SCANA CORPORATION, a South Carolina corporation (the "Company").

RECITALS

WHEREAS, the board of directors of Parent has approved this Agreement and the transactions contemplated by this Agreement, including the merger of Merger Sub with and into the Company (the "Merger"), on the terms and subject to the conditions set forth in this Agreement;

WHEREAS, the board of directors of the Company (the "Company Board") has (a) determined that it is in the best interests of the Company and the shareholders of the Company that the Company enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement on the terms and subject to the conditions set forth in this Agreement, (b) adopted this Agreement and approved the transactions contemplated by this Agreement, including the Merger, (c) directed that the approval of this Agreement be submitted to a vote at a meeting of the shareholders of the Company and (d) resolved to recommend that the shareholders of the Company approve this Agreement;

WHEREAS, the board of directors of Merger Sub has (a) determined that it is in the best interests of Merger Sub and the sole shareholder of Merger Sub that Merger Sub enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement on the terms and subject to the conditions set forth in this Agreement, (b) adopted this Agreement and approved the transactions contemplated by this Agreement, including the Merger and (c) resolved to recommend that the sole shareholder of Merger Sub approve this Agreement;

WHEREAS, for U.S. federal income tax purposes, the Merger is intended to qualify as a "reorganization" within the meaning of Section 368(a) of the Code (the "Intended Tax Treatment"), and this Agreement is intended to be a "plan of reorganization" for purposes of Sections 354 and 361 of the Code; and

WHEREAS, the Company, Parent and Merger Sub desire to make certain representations, warranties, covenants and agreements in connection with the Merger and also to prescribe various conditions to the Merger.

NOW, THEREFORE, in consideration of the premises, and of the representations, warranties, covenants and agreements contained in this Agreement, and intending to be legally bound hereby, the Company, Parent and Merger Sub hereby agree as follows:

ARTICLE I

THE MERGER

SECTION 1.01. The Merger. Upon the terms and subject to the conditions set forth in this Agreement and in accordance with the SCBCA, at the Effective Time, Merger Sub shall be merged with and into the Company and the separate corporate existence of Merger Sub shall thereupon cease and the Company shall continue as the surviving corporation in the Merger (the "Surviving Corporation") and a wholly-owned Subsidiary of Parent. The Merger shall have the effects set forth in this Agreement and in the applicable provisions of the SCBCA.
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SECTION 1.02. Closing. The closing of the Merger (the "Closing") shall take place at the offices of Mayer Brown LLP, 71 South Wacker Drive, Chicago, Illinois 60606, at 9:00 a.m., local time, on the third (3rd) Business Day following the day on which all of the conditions set forth in Article VI (other than those conditions that by their nature are to be satisfied at the Closing, but subject to the satisfaction or waiver of those conditions at the Closing) have been satisfied or waived in accordance with this Agreement, or at such other time and place as the Company and Parent may agree in writing. The date on which the Closing occurs is referred to in this Agreement as the "Closing Date".

SECTION 1.03. Effective Time. As soon as practicable on the Closing Date, the Company and Parent will cause the Merger to become effective by filing the articles of merger (the "Articles of Merger") with the Secretary of State of the State of South Carolina, which Articles of Merger will be executed and filed in accordance with the applicable provisions of the SCBCA. The Merger shall become effective at the time when the Articles of Merger have been duly filed with the Secretary of State of the State of South Carolina or at such later time as may be agreed by Parent and the Company in writing and specified in the Articles of Merger (the "Effective Time").

SECTION 1.04. Articles of Incorporation; Bylaws.

(a) At the Effective Time, the articles of incorporation of the Company, as in effect immediately prior to the Effective Time, shall be the articles of incorporation of the Surviving Corporation until thereafter amended in accordance with the provisions thereof and applicable Law; provided, however, that no such amendment shall be inconsistent with the obligations of Parent under Section 5.08(b).

(b) At the Effective Time, the bylaws of the Company, as in effect immediately prior to the Effective Time, shall be amended as of the Effective Time to be in the form of the bylaws of Merger Sub as of the date hereof (except with respect to the name of the Company, which shall be "SCANA Corporation"), with any changes necessary so that such bylaws shall be in compliance with Section 5.08 and, to the extent not inconsistent with any of the foregoing, such other changes as Parent deems necessary or appropriate) and as so amended shall be the bylaws of the Surviving Corporation until thereafter amended as provided therein or by applicable Law; provided, however, that no such amendment shall be inconsistent with the obligations of Parent under Section 5.08(b).

SECTION 1.05. Directors and Officers.

(a) The directors of Merger Sub will be appointed by Parent pursuant to applicable Law to be the directors of the Surviving Corporation after the Effective Time following the resignation or removal of the individuals serving as directors of the Company prior to the Effective Time in accordance with Section 5.15, with such directors appointed by Parent to serve until their respective successors have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the articles of incorporation and the bylaws of the Surviving Corporation.

(b) The officers of the Company as of immediately prior to the Effective Time shall, from and after the Effective Time, be the officers of the Surviving Corporation until their respective successors have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the articles of incorporation and the bylaws of the Surviving Corporation.

SECTION 1.06. Plan of Merger. This Agreement will constitute a "plan of merger" for purposes of the SCBCA.

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ARTICLE II

EFFECT OF THE MERGER ON THE CAPITAL STOCK OF THE CONSTITUENT CORPORATIONS

SECTION 2.01. Effect on Capital Stock. At the Effective Time, by virtue of the Merger and without any action on the part of the Company, Parent, Merger Sub or the holders of any shares of capital stock of the Company, Parent or Merger Sub:

(a) Merger Consideration. Each Company Share issued and outstanding immediately prior to the Effective Time (other than the Cancelled Shares, which shall be treated in accordance with Section 2.01(b)) shall cease to be outstanding, shall be cancelled and shall cease to exist, and each such Company Share, whether represented by a certificate ("Certificate") or in non-certificated form and represented by book-entry ("Book-Entry Share"), shall automatically be converted into the right to receive 0.6690 validly issued, fully paid and non-assessable Parent Shares (the "Merger Consideration"). Following the Effective Time, the holders of Company Shares as of immediately prior to the Effective Time shall cease to have any rights with respect thereto, except for the rights set forth in Section 2.03(b)(v).

(b) Cancellation of Cancelled Shares. Each Company Share owned by Parent, Merger Sub or any other wholly-owned Subsidiary of Parent and each Company Share owned by the Company or any wholly-owned Subsidiary of the Company (collectively, the "Cancelled Shares") shall cease to be outstanding, shall be cancelled without payment of any consideration therefor and shall cease to exist.

(c) Capital Stock of Merger Sub. Each share of common stock, without par value, of Merger Sub issued and outstanding immediately prior to the Effective Time shall be converted into and become one (1) validly issued, fully paid and non-assessable share of common stock, without par value, of the Surviving Corporation, and all such shares together shall constitute the only outstanding shares of capital stock of the Surviving Corporation.

SECTION 2.02. Treatment of Company Equity Awards.

(a) Treatment of Performance Shares. At the Effective Time, each performance share award granted under a Company Equity Award Plan that is outstanding immediately prior to the Effective Time (a "Company Performance Share Award") shall fully vest at the target level of performance and shall be cancelled and converted automatically into the right to receive the Equity Award Consideration in respect of each Company Share underlying such Company Performance Share Award.

(b) Treatment of Restricted Stock Units. At the Effective Time, each restricted stock unit award in respect of Company Shares granted under a Company Equity Award Plan that is outstanding immediately prior to the Effective Time (a "Company RSU") shall fully vest and shall be cancelled and converted automatically into the right to receive the Equity Award Consideration in respect of each Company Share underlying such Company RSU.

(c) Treatment of Deferred Units. At the Effective Time, each deferred unit in respect of Company Shares credited or deemed credited to the Company stock ledger under the Director Compensation and Deferral Plan or the Executive Deferred Compensation Plan that is outstanding immediately prior to the Effective Time (a "Company Deferred Unit") shall be converted automatically into a number of deferred unit(s) in respect of Parent Shares equal to the product of (x) the Company Deferred Unit multiplied by (y) the Merger Consideration, to be payable pursuant to the terms of the applicable plan.

(d) Payment. The Surviving Corporation shall pay the Equity Award Consideration as required under Section 2.02(a) and Section 2.02(b) as soon as reasonably practicable after the Effective Time (but in any event

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within three (3) Business Days thereafter); provided, however, that to the extent any such payment relates to any Company Performance Share Awards or Company RSUs that are nonqualified deferred compensation subject to Section 409A of the Code, the Surviving Corporation shall make such payment at the earliest time permitted under, and in accordance with, the terms of the applicable award agreement or other relevant documents and in accordance with Section 409A of the Code.

(e) Corporate Actions. At or prior to the Effective Time, the Company, the Company Board or any authorized committee thereof, as applicable, shall adopt any resolutions and take any actions that are necessary to effectuate the provisions of Section 2.02(a), Section 2.02(b) and Section 2.02(c). The Company shall take all actions necessary to ensure that, from and after the Effective Time, neither Parent nor the Surviving Corporation will be required to deliver Company Shares or other capital stock of the Company to any Person pursuant to or in settlement of Company Performance Share Awards, Company RSUs, Company Deferred Units or any other awards under any Company Equity Award Plan.

SECTION 2.03. Exchange of Company Shares.

(a) Exchange Agent. Prior to the Effective Time, Parent shall select a paying and exchange agent reasonably acceptable to the Company (the "Exchange Agent") and enter into an agreement with such Exchange Agent in form and substance reasonably acceptable to the Company pursuant to which the Exchange Agent will (i) act as agent for the shareholders of the Company in connection with the Merger and receive payment and delivery of the Merger Consideration to which the shareholders of the Company shall become entitled pursuant to Section 2.01(a) and (ii) act as agent for Parent in transmitting the Merger Consideration to such shareholders following the occurrence of the Effective Time in accordance with this Agreement. At or prior to the Effective Time, Parent shall deposit, or cause to be deposited, with the Exchange Agent, in trust for the benefit of the holders of Company Shares, an amount of Parent Shares in book-entry form sufficient for the Exchange Agent to pay and deliver the Merger Consideration required to be paid and delivered by Parent in accordance with Section 2.01(a). In addition, Parent shall deposit, or cause to be deposited, with the Exchange Agent, from time to time after the Effective Time, (A) any dividends or other distributions payable pursuant to Section 2.03(g) and (B) cash in lieu of any fractional Parent Shares payable pursuant to Section 2.03(h). All cash and Parent Shares, together with any dividends or other distributions, deposited with the Exchange Agent pursuant to this Section 2.03(a) shall be referred to as the "Exchange Fund."

(b) Exchange Procedures.

(i) Transmittal Materials and Instructions. Promptly after the Effective Time (and in any event within three (3) Business Days thereafter), Parent shall cause the Exchange Agent to mail or otherwise provide to each holder of record of Company Shares (other than holders of Cancelled Shares) (A) transmittal materials, including a letter of transmittal in form as agreed by Parent and the Company, specifying that delivery shall be effected, and risk of loss and title shall pass, with respect to Book-Entry Shares, only upon delivery of an "agent's message" regarding the book-entry transfer of Book-Entry Shares (or such other evidence, if any, of the transfer as the Exchange Agent may reasonably request), and with respect to Certificates, only upon delivery of the Certificates (or affidavits of loss in lieu of the Certificates as provided in Section 2.03(f) to the Exchange Agent), such transmittal materials to be in such form and have such other provisions as Parent and the Company may reasonably agree, and (B) instructions for use in effecting the surrender of the Book-Entry Shares or Certificates (or affidavits of loss in lieu of the Certificates as provided in Section 2.03(f)) to the Exchange Agent.

(ii) Certificates. Upon surrender of a Certificate (or affidavit of loss in lieu of the Certificate as provided in Section 2.03(f)) to the Exchange Agent in accordance with the terms of transmittal materials and instructions referred to in Section 2.03(b)(i), the holder of such Certificate shall be entitled to receive in exchange therefor (A) a cash amount in immediately available funds equal to (1) any dividends and other distributions such holder has the right to receive pursuant to Section 2.03(g) plus (2) any cash in lieu of any fractional Parent Shares such holder has the right to receive pursuant to Section 2.03(h) and (B) the number

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of Parent Shares, in uncertificated book-entry form, equal to the number of Company Shares represented by such Certificate (or affidavit of loss in lieu of the Certificate as provided in Section 2.03(f)) multiplied by the Merger Consideration. No interest will be paid or accrued on any cash amount payable upon due surrender of the Certificates.

(iii) Book-Entry Shares. Notwithstanding anything to the contrary contained in this Agreement, any holder of Book-Entry Shares shall not be required to deliver a Certificate or an executed letter of transmittal to the Exchange Agent to receive the aggregate Merger Consideration that such holder is entitled to receive as a result of the Merger pursuant to Section 2.01(a). In lieu thereof, each holder of record of one or more Book-Entry Shares (other than Cancelled Shares) shall upon receipt by the Exchange Agent of an "agent's message" in customary form (it being understood that the holders of Book-Entry Shares shall be deemed to have surrendered such Company Shares upon receipt by the Exchange Agent of such "agent's message" or such other evidence, if any, as the Exchange Agent may reasonably request) be entitled to receive, and Parent shall cause the Exchange Agent to pay and deliver as promptly as practicable after the Effective Time, (A) a cash amount in immediately available funds equal to (1) any dividends and other distributions such holder has the right to receive pursuant to Section 2.03(g) plus (2) any cash in lieu of any fractional Parent Shares such holder has the right to receive pursuant to Section 2.03(h) and (B) the number of Parent Shares, in uncertificated book-entry form, equal to the number of Company Shares represented by such Book-Entry Shares multiplied by the Merger Consideration. No interest will be paid or accrued on any cash amount payable upon due surrender of the Book-Entry Shares.

(iv) Unrecorded Transfers; Other Payments. In the event of a transfer of ownership of Company Shares that is not registered in the transfer records of the Company or if payment and delivery of the Merger Consideration and the other payments contemplated by Section 2.01(a) and this Section 2.03 is to be made to a Person other than the Person in whose name the surrendered Certificate or Book-Entry Share is registered, such Certificate or Book-Entry Share may be exchanged in accordance with this Article II if the Certificate or Book-Entry Share formerly representing such Company Shares is presented to the Exchange Agent accompanied by all documents required to evidence and effect such transfer and to evidence that any applicable transfer or other similar Taxes have been paid or are not applicable.

(v) Rights of Holders of Company Shares; Expenses. Until surrendered or exchanged pursuant to this Section 2.03(b), each Certificate or Book-Entry Share shall be deemed at any time after the Effective Time to represent only the right to receive upon such surrender or exchange the Merger Consideration pursuant to Section 2.01(a), any dividends and other distributions pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h). Parent shall pay all charges and expenses, including those of the Exchange Agent, in connection with the exchange of Company Shares pursuant to this Article II.

(c) Termination of the Exchange Fund; No Liability. Any portion of the Exchange Fund (including the proceeds of any investment thereof) that remains undistributed one (1) year after the Effective Time shall be delivered to Parent or the Surviving Corporation, upon demand by Parent. Any holders of Company Shares (other than Cancelled Shares) who have not theretofore complied with this Article II shall thereafter be entitled to look only to Parent and the Surviving Corporation for payment and delivery of the Merger Consideration pursuant to Section 2.01(a), any dividends and other distributions pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h) upon surrender of their Certificates or exchange of their Book-Entry Shares in accordance with the provisions set forth in Section 2.03(b), and Parent and the Surviving Corporation shall remain liable for (subject to applicable abandoned property, escheat or other similar Law) payment of their claims for the Merger Consideration payable upon surrender of their Certificates or exchange of their Book-Entry Shares. Notwithstanding the foregoing, none of the Surviving Corporation, Parent, the Company, the Exchange Agent or any other Person shall be liable to any former holder of Company Shares for any amount properly delivered to a public official pursuant to applicable abandoned property, escheat or other similar Law.

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(d) Investment of the Exchange Fund. The Exchange Agent shall invest the cash portion of the Exchange Fund as directed by Parent; provided, however, that such investments shall be in obligations of or guaranteed by the United States of America, in commercial paper obligations rated A-1 or P-1 or better by Moody's Investors Service, Inc. or Standard & Poor's Corporation, respectively, in certificates of deposit, bank repurchase agreements or banker's acceptances of commercial banks with capital exceeding $1 billion, or in money market funds which are invested in instruments that consist of U.S. Treasury obligations and repurchase agreements collateralized by U.S. Treasury obligations or having a rating in the highest investment category granted by a recognized credit rating agency at the time of acquisition or a combination of the foregoing and, in any such case, no such instrument shall have a maturity that could prevent or delay payments to be made pursuant to this Agreement. Subject to Section 2.03(c), to the extent that there are losses with respect to such investment of the cash portion of the Exchange Fund, or the cash portion of the Exchange Fund diminishes for other reasons, such that the amount of cash in the Exchange Fund is below the level required to make prompt cash payment of any dividends and other distributions pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h), Parent shall promptly replace or restore the cash in the Exchange Fund lost through such investments or other events so as to ensure that the Exchange Fund is at all applicable times maintained at a level sufficient to make such cash payments. Any interest and other income resulting from such investment shall become a part of the Exchange Fund, and any amounts in excess of the aggregate amount of the payments described in the immediately preceding sentence will be promptly returned to Parent or the Surviving Corporation, as requested by Parent. The Exchange Fund shall not be used for any purpose other than as contemplated by Section 2.03(a) and this Section 2.03(d).

(e) Transfers. From and after the Effective Time, the stock transfer books of the Company shall be closed and there shall be no transfers on the stock transfer books of the Company of the Company Shares that were outstanding immediately prior to the Effective Time. If, after the Effective Time, acceptable evidence of a Certificate or Book-Entry Share is presented to the Surviving Corporation, Parent or the Exchange Agent for transfer, (i) in the case of Certificates, the holder of such Certificate shall be given a copy of the transmittal materials and instructions referred to in Section 2.03(b)(i) and instructed to comply with the instructions thereto in order to receive the Merger Consideration pursuant to Section 2.01(a) and (ii) in the case of Book-Entry Shares, such Book-Entry Share shall be cancelled and exchanged as contemplated by this Article II.

(f) Lost Certificates. In the case of any Certificate that has been lost, stolen or destroyed, upon the making of an affidavit of that fact by the Person claiming such Certificate to be lost, stolen or destroyed and, if required by the Exchange Agent or Parent, the posting by such Person of a bond in a reasonable amount as indemnity against any claim that may be made against it with respect to such Certificate, the Exchange Agent shall pay and deliver in exchange for such Certificate the Merger Consideration pursuant to Section 2.01(a), any dividends or other distributions payable pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h).

(g) Dividends.

(i) Certificates. No dividends or other distributions declared or made with respect to Parent Shares with a record date after the Effective Time shall be paid to the holder of any Certificate with respect to the Parent Shares that such holder would be entitled to receive upon surrender of such Certificate, until such holder shall surrender such Certificate in accordance with Section 2.03(b)(ii). Subject to applicable Law, following surrender of any such Certificate, there shall be paid to the holder of Parent Shares issued in exchange therefor, without interest, (A) promptly after the time of such surrender, the amount of dividends and other distributions with a record date after the Effective Time but prior to such surrender and a payment date prior to such surrender payable with respect to such Parent Shares and (B) at the appropriate payment date, the amount of dividends and other distributions with a record date after the Effective Time but prior to such surrender and a payment date subsequent to such surrender payable with respect to such Parent Shares.

(ii) Book-Entry Shares. Subject to applicable Law, there shall be paid to the holder of Parent Shares issued in exchange for Book-Entry Shares in accordance with Section 2.03(b)(iii), without interest,

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(A) promptly upon receipt by the Exchange Agent of an "agent's message" (or such other evidence, if any, of surrender as the Exchange Agent may reasonably request), the amount of dividends and other distributions with a record date after the Effective Time but prior to such receipt and a payment date prior to such receipt payable with respect to such Parent Shares and (B) at the appropriate payment date, the amount of dividends and other distributions with a record date after the Effective Time but prior to such receipt and a payment date subsequent to such receipt payable with respect to such Parent Shares.

(h) Fractional Shares. No certificates or scrip representing fractional Parent Shares shall be issued upon the conversion of the Company Shares into the Merger Consideration pursuant to Section 2.01(a), and such fractional share interests shall not entitle the owner thereof to vote or to any rights of a holder of Parent Shares. For purposes of this Section 2.03(h), all fractional shares to which a single record holder would be entitled shall be aggregated and calculations shall be rounded to four (4) decimal places. In lieu of any such fractional Parent Shares, each holder of Company Shares who would otherwise be entitled to such fractional Parent Shares shall be entitled to receive an amount in cash, without interest, rounded to the nearest cent, equal to the product of (i) the amount of such fractional Parent Share and (ii) the Average Price.

SECTION 2.04. Withholding Rights. Each of Parent and the Surviving Corporation shall be entitled to deduct and withhold from the consideration otherwise payable pursuant to this Agreement to any holder of Company Shares, Company Performance Share Awards and Company RSUs such amounts as it is required to deduct and withhold with respect to the making of such payment under the Code or any other applicable state, local or foreign Tax Law, taking into account any applicable exemption under such Law. To the extent that amounts are so withheld by Parent or the Surviving Corporation, as the case may be, such withheld amounts (a) shall be promptly remitted by Parent or the Surviving Corporation, as applicable, to the applicable Governmental Entity and (b) shall be treated for all purposes of this Agreement as having been paid to the holder of Company Shares, Company Performance Share Awards and Company RSUs (as applicable) in respect of which such deduction and withholding were made by the Surviving Corporation or Parent, as the case may be.

SECTION 2.05. No Dissenters' Rights. In accordance with Section 33-13-102(B) of the SCBCA, no holder of Company Shares shall be entitled to exercise dissenters' rights, appraisal rights or other similar rights in connection with the Merger and the other transactions contemplated by this Agreement.

SECTION 2.06. Adjustments . In the event of any change to the Company Shares or Parent Shares (or securities convertible thereto or exchangeable or exercisable therefor) issued and outstanding in the period between the date of this Agreement and the Effective Time as a result of a reclassification, stock split (including a reverse stock split), stock dividend or distribution, recapitalization, exchange or readjustment of shares, merger, issuer tender or exchange offer, or other similar transaction, the Merger Consideration and any other payments to be made pursuant to this Article II shall be equitably adjusted, without duplication, to provide the holders of Company Shares, Company Performance Share Awards, Company RSUs and Company Deferred Units the same economic effect contemplated by this Agreement prior to such change; provided, however, that nothing in this Section 2.06 shall be construed to permit the Company, Parent, any of their respective Subsidiaries or any other Person to take any action that is otherwise prohibited by the terms of this Agreement; and provided, further, that any adjustment pursuant to this Section 2.06 to any Company Performance Share Awards, Company RSUs and Company Deferred Units shall be done in all respects in accordance with Section 409A of the Code, if applicable, and the terms of the applicable Company Equity Award Plan.

ARTICLE III

REPRESENTATIONS AND WARRANTIES

SECTION 3.01. Representations and Warranties of the Company. Except (x) as disclosed in the SEC Reports of the Company or South Carolina Electric & Gas Company (each, a "Reporting Company") filed with
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or furnished to the SEC since January 1, 2016 and publicly available at least twenty-four (24) hours prior to the date of this Agreement (excluding any disclosures set forth in any risk factor section or in any other section to the extent such disclosures are forward-looking statements or are cautionary, predictive or forward-looking in nature) or (y) as set forth in the Company Disclosure Letter (it being agreed that disclosure of any item in any section or subsection of the Company Disclosure Letter shall also be deemed disclosed with respect to any other section or subsection of this Agreement to which the relevance of such item is reasonably apparent), the Company represents and warrants to Parent and Merger Sub as follows:

(a) Organization, Standing and Corporate Power. The Company is a corporation duly incorporated and validly existing under the Laws of the State of South Carolina and has all requisite corporate power and authority to carry on its business as currently conducted and is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Each of the Company's Subsidiaries is a legal entity duly organized, validly existing and in good standing (where such concept is recognized under applicable Law) under the Law of its jurisdiction of organization and has all requisite corporate or similar power and authority to carry on its business as currently conducted, and each of the Company's Subsidiaries is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company has made available to Parent a true and complete copy of the Restated Articles of Incorporation of the Company and any amendments thereto (collectively, the "Company Articles of Incorporation") and the Amended and Restated Bylaws of the Company (the "Company Bylaws" and together with the Company Articles of Incorporation, the "Company Organizational Documents").

(b) Subsidiaries. Section 3.01(b) of the Company Disclosure Letter sets forth a list of all Subsidiaries of the Company. All of the outstanding shares of capital stock of, or other equity interests in, each Subsidiary of the Company have, in all cases, been duly authorized and validly issued and are fully paid, non-assessable and not subject to preemptive rights, and are wholly-owned, directly or indirectly, by the Company free and clear of all pledges, liens, charges, mortgages, encumbrances, adverse claims and interests, licenses, purchase options, call options, rights of first offer and rights of first refusal, easements, rights-of-way, security interests and other use agreements, covenants and encroachments of any kind or nature whatsoever (including any restriction on the right to vote or transfer the same, except for such transfer restrictions of general applicability as may be provided under the Securities Act, the "blue sky" Laws of the various States of the United States or similar Law of other applicable jurisdictions) (collectively, "Liens"), other than transfer restrictions contained in the articles of incorporation, bylaws and limited liability company agreements (or any equivalent constituent documents) of such Subsidiary. Except for its interests in its Subsidiaries, the Company does not own, directly or indirectly, any capital stock of, or other equity interests in, any Person. The Company has made available to Parent true and complete copies of the articles of incorporation, bylaws and limited liability company agreements (or equivalent constituent documents) of each Subsidiary of the Company as in effect on the date of this Agreement.

(c) Capital Structure.

(i) The authorized capital stock of the Company consists of 200,000,000 Company Shares. The Company is not authorized to issue any preferred stock. At the close of business on December 29, 2017, there were (A)(1)142,916,916.594 Company Shares issued and outstanding and (2) 269,647.326 Company Shares held by the Company in its treasury, (B) 454,325 Company Shares underlying the outstanding Company Performance Share Awards (assuming target level performance), (C) 215,200 Company Shares underlying the outstanding Company RSUs (assuming achievement of required performance measure(s))

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and (D) 269,647.326 Company Shares underlying ledgers pursuant to the Director Compensation and Deferral Plan. Except as set forth in the immediately preceding sentence, at the close of business on December 29, 2017, no shares of capital stock or other voting securities of the Company were issued or outstanding or subject to outstanding awards under the Company Equity Award Plans. Since December 29, 2017 to the date of this Agreement, (x) there have been no issuances by the Company of shares of capital stock or other voting securities of the Company other than pursuant to the exercise or vesting of equity awards under the Company Equity Award Plans, in each case, outstanding as of December 29, 2017 and (y) there have been no issuances by the Company of options, warrants, other rights to acquire shares of capital stock of the Company or other rights that give the holder thereof any economic interest of a nature accruing to the holders of Company Shares. All outstanding Company Shares are, and all such Company Shares that may be issued prior to the Effective Time will be when issued, duly authorized, validly issued, fully paid and non-assessable and not subject to preemptive rights.

(ii) No Subsidiary of the Company owns any Company Shares or other shares of capital stock of the Company. There are no bonds, debentures, notes or other Indebtedness of the Company or of any of its Subsidiaries that give the holders thereof the right to vote (or that are convertible into, or exchangeable for, securities having the right to vote) on any matters on which holders of Company Shares may vote ("Voting Company Debt"). Except for any obligations pursuant to this Agreement or as otherwise set forth in Section 3.01(c)(i), as of December 29, 2017, there are no options, warrants, rights (including preemptive, conversion, stock appreciation, redemption or repurchase rights), convertible or exchangeable securities, stock-based performance units, Contracts or undertakings of any kind to which the Company or any of its Subsidiaries is a party or by which any of them is bound (A) obligating the Company or any of its Subsidiaries to issue, deliver or sell, or cause to be issued, delivered or sold, additional shares of capital stock or other securities of, or equity interests in, or any security convertible or exchangeable for any capital stock or other security of, or equity interest in, the Company or any of its Subsidiaries or any Voting Company Debt, (B) obligating the Company or any of its Subsidiaries to issue, grant or enter into any such option, warrant, right, security, unit, Contract or undertaking to declare or pay any dividend or distribution or (C) that give any Person the right to subscribe for or acquire any securities of the Company or any of its Subsidiaries, or to receive any economic interest of a nature accruing to the holders of Company Shares or otherwise based on the performance or value of shares of capital stock of the Company or any of its Subsidiaries. As of the date of this Agreement, there are no outstanding obligations of the Company or any of its Subsidiaries to repurchase, redeem or otherwise acquire any shares of capital stock or other equity interest of the Company or any of its Subsidiaries, other than pursuant to the Company Equity Award Plans. There are no voting agreements, voting trusts, shareholders agreements, proxies or other agreements to which the Company or any of its Subsidiaries is bound with respect to the voting of the capital stock or other equity interests of the Company, or restricting the transfer of, or providing registration rights with respect to, such capital stock or equity interests.

(d) Authority; Noncontravention.

(i) The Company has all requisite corporate power and authority to execute and deliver, and perform its obligations under, this Agreement and to consummate the transactions contemplated by this Agreement, subject, in the case of the Merger only, to receipt of the Company Requisite Vote. The execution, delivery and performance of this Agreement by the Company and the consummation by the Company of the transactions contemplated by this Agreement have been duly authorized by all necessary corporate action on the part of the Company, subject, in the case of the Merger only, to receipt of the Company Requisite Vote. This Agreement has been duly executed and delivered by the Company and, assuming the due authorization, execution and delivery by each of the other parties hereto, constitutes a legal, valid and binding obligation of the Company, enforceable against the Company in accordance with its terms, subject, as to enforceability, bankruptcy, insolvency and other Law of general applicability relating to or affecting creditors' rights and to general equity principles. The Company Board has duly and validly adopted resolutions (A) determining that it is in the best interests of the Company and the shareholders of the Company that the Company enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement

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on the terms and subject to the conditions set forth in this Agreement, (B) adopting this Agreement and approving the transactions contemplated by this Agreement, including the Merger, (C) directing that the approval of this Agreement be submitted to a vote at a meeting of the shareholders of the Company and (D) recommending that the shareholders of the Company approve this Agreement (the "Company Board Recommendation"), which resolutions, as of the date of this Agreement, have not been rescinded, modified or withdrawn in any way.

(ii) The execution, delivery and performance by the Company of this Agreement do not, and the consummation of the Merger and the other transactions contemplated by this Agreement and compliance with the provisions of this Agreement will not, conflict with, or result in any violation of, or default (with or without notice or lapse of time, or both) under, or give rise to any right (including a right of termination, cancellation or acceleration of any obligation or any right of first refusal, participation or similar right) under, or cause the loss of any benefit under, or result in the creation of any Lien (other than Permitted Liens) upon any of the properties or assets of the Company or any of its Subsidiaries under, any provision of (A) the Company Organizational Documents or the comparable organizational documents of any of the Company's Subsidiaries or (B) subject to the filings and other matters referred to in Section 3.01(d)(iii), (1) any Contract, or (2) any Law, in each case, applicable to the Company or any of its Subsidiaries or any of their respective properties or assets, other than, in the case of the foregoing clause (B), any such conflicts, violations, defaults, rights, losses or Liens that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iii) No Consent of, or registration, declaration or filing with, or notice to, any Governmental Entity is required to be obtained or made by or with respect to the Company or any of its Subsidiaries in connection with the execution, delivery and performance of this Agreement by the Company or the consummation by the Company of the Merger and the other transactions contemplated by this Agreement, except for (A) the Regulatory Conditions and any other Consents of or under, and compliance with any other applicable requirements of, (1) the HSR Act, (2) the Federal Energy Regulatory Commission (the "FERC"), (3) the U.S. Nuclear Regulatory Commission (the "NRC"), (4) the Federal Communications Commission (the "FCC"), (5) the North Carolina Utilities Commission (the "NCUC"), and (6) the Georgia Public Service Commission (the "GPSC") (the items set forth in this clause (A), collectively, the "Company Regulatory Clearances"), (B) the filing with the SEC of such reports and other documents (including the filing of the Proxy Statement/Prospectus) under, and compliance with all other applicable requirements of, the Securities Act or the Exchange Act and the rules and regulations promulgated thereunder and any applicable state securities, takeover and "blue sky" Laws, (C) the filing of the Articles of Merger with the Secretary of State of the State of South Carolina, (D) any filings under, and compliance with all other applicable requirements of, the rules and regulations of the NYSE and (E) such other Consents, registrations, declarations, filings and notices, the failure of which to be obtained or made has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect and would not reasonably be expected to prevent, or materially impair or delay, the consummation of the Merger or any of the other material transactions contemplated by this Agreement.

(e) Applicable Company SEC Reports; Financial Statements; Undisclosed Liabilities.

(i) The Reporting Companies have filed or furnished, as applicable, all SEC Reports such companies were required or otherwise obligated to file with or furnish to the SEC since June 30, 2016 (such SEC Reports, the "Applicable Company SEC Reports"). As of their respective dates of filing, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, the Applicable Company SEC Reports complied in all material respects with the applicable requirements of the Securities Act, the Exchange Act and the Sarbanes-Oxley Act, as the case may be, and the applicable rules and regulations promulgated thereunder, each as in effect on the date of any such filing. As of the time of filing with the SEC (or, if amended prior to the date of this Agreement, as of the date of such amendment), none of the Applicable Company SEC Reports so filed contained any untrue statement of a material fact or omitted to state a

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material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading, except to the extent that the information in such Applicable Company SEC Reports has been amended or superseded by a later Applicable Company SEC Report.

(ii) As of their respective dates, the audited and unaudited financial statements (consolidated, as applicable, and including any related notes thereto) of each of the Reporting Companies and their Subsidiaries, as applicable, included in the Applicable Company SEC Reports have been prepared in all material respects (except, as applicable, as permitted by Form 10-Q of the SEC or other applicable rules and regulations of the SEC) in accordance with United States generally accepted accounting principles ("GAAP") applied on a consistent basis during the periods involved (except as may be indicated in the notes thereto) and fairly present in all material respects the consolidated financial position of each Reporting Company and its Subsidiaries, as applicable, as of the respective dates thereof (taking into account the notes thereto) and the consolidated results of their operations and cash flows for the periods indicated (taking into account the notes thereto) and subject, in the case of unaudited financial statements, to normal year-end adjustments.

(iii) Each Reporting Company maintains disclosure controls and procedures required by Rule 13a-15(e) or Rule 15d-15(e) under the Exchange Act and such disclosure controls and procedures are effective in all material respects to ensure that information required to be disclosed by such Reporting Company in the SEC Reports it files or submits under the Exchange Act is recorded, processed, summarized and reported on a timely basis to the individuals responsible for the preparation of such Reporting Company's SEC Reports and other public disclosure documents. Each Reporting Company maintains internal control over financial reporting required by Rule 13a-15(f) or Rule 15d-15(f) under the Exchange Act and such internal control is effective in all material respects in providing reasonable assurance regarding the reliability of such Reporting Company's financial reporting and such Reporting Company's preparation of financial statements for external purposes in accordance with GAAP. Each Reporting Company has disclosed, based on its most recent evaluation prior to the date of this Agreement, to such Reporting Company's outside auditors and the audit committee of such Reporting Company's board of directors, (A) any significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that are reasonably likely to adversely affect such Reporting Company's ability to record, process, summarize and report financial information and (B) to the Knowledge of the Company, any fraud that involves management or other employees of such Reporting Company who have a significant role in such Reporting Company's internal control over financial reporting.

(iv) There are no liabilities or obligations of any Reporting Company or any Subsidiary of any Reporting Company of a nature that would be required under GAAP to be reflected or reserved on a balance sheet (consolidated, as applicable) of such Reporting Company, other than (A) liabilities or obligations reflected or reserved against in such Reporting Company's most recent balance sheet (including the notes thereto) included in the Applicable Company SEC Reports filed prior to the date hereof, (B) liabilities or obligations incurred in the ordinary course of business consistent with past practice since September 30, 2017, (C) liabilities or obligations incurred under or in accordance with this Agreement or in connection with the transactions contemplated by this Agreement and (D) liabilities or obligations that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(f) Absence of Certain Changes or Events.

(i) Since January 1, 2017, there have not been any changes, developments, circumstances, effects, events or occurrences (changes, developments, circumstances, effects, events and occurrences being collectively referred to as "Changes") that have had or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

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(ii) Since January 1, 2017, except as contemplated or required by this Agreement, the Company and its Subsidiaries have conducted their respective businesses in all material respects in the ordinary course of business consistent with past practice.

(g) Litigation. There is no (i) material suit, action, arbitration, mediation or legal, arbitral, administrative or other proceeding (a "Proceeding") pending or, to the Knowledge of the Company, threatened against the Company or any of its Subsidiaries, (ii) to the Knowledge of the Company, pending or threatened material investigation or inquiry by a Governmental Entity of the Company or any of its Subsidiaries and (iii) Order, decree or writ of any Governmental Entity outstanding or, to the Knowledge of the Company, threatened to be imposed against the Company or any of its Subsidiaries.

(h) Contracts. Except for this Agreement and the Contracts set forth in Section 3.01(h) of the Company Disclosure Letter and Company Benefit Plans, as of the date of this Agreement, neither the Company nor any of its Subsidiaries is a party to any Company Material Contract. Each Company Material Contract required to be filed by the Company as a "material contract" pursuant to Item 601(b)(10) of Regulation S-K under the Securities Act has been so filed. Each of the Company Material Contracts is valid and binding on the Company or the Subsidiary of the Company party thereto and, to the Knowledge of the Company as of the date hereof, each other party thereto, and is in full force and effect, except for such failures to be valid and binding or to be in full force and effect that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. There is no default under any Company Material Contract by the Company or any of its Subsidiaries or, to the Knowledge of the Company as of the date hereof, by any other party thereto, in each case except for such defaults that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(i) Compliance with Law; Permits. Since January 1, 2016, the Company and each of its Subsidiaries have been in compliance with and have not been in default under or in violation of any applicable Law, except where such non-compliance, default or violation has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Since January 1, 2016, neither the Company nor any of its Subsidiaries has received any written notice from any Governmental Entity regarding any actual or possible violation of, or failure to comply with, any Law, except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company and its Subsidiaries are in possession of all franchises, grants, permits, easements, variances, exceptions, Consents, certificates, permissions, qualifications and registrations and Orders of all Governmental Entities (collectively, "Permits"), and have filed all tariffs, reports, notices, and other documents with all Governmental Entities, necessary for the Company and its Subsidiaries to own, lease and operate their properties and assets and to carry on their businesses as currently conducted, except where the failure to possess any of such Permits or make any such filings has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. All such Permits are valid and in full force and effect and there are no pending or, to the Knowledge of the Company, threatened administrative or judicial Proceedings that would reasonably be expected to result in modification, termination or revocation thereof, except where the failure to be in full force and effect or any modification, termination or revocation thereof has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Since January 1, 2016, the Company and each of its Subsidiaries have been in compliance with the terms and requirements of such Permits, except where the failure to be in compliance has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(j) Labor and Employment Matters.

(i) Neither the Company nor any of its Subsidiaries is a party to any collective bargaining agreement or other similar agreement with a labor union, works council or similar organization. To the Knowledge of the Company, as of the date hereof, (A) there are no union or other labor organizing activities occurring concerning any employees of the Company or any of its Subsidiaries and (B) there are no labor strikes,

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slowdowns, work stoppages or lockouts pending or threatened in writing against the Company or any of its Subsidiaries, except, in each case, as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Since January 1, 2016, the Company and its Subsidiaries have not engaged in any action that required any notifications under the Workers Adjustment and Retraining Notification (WARN) Act of 1989, as amended, except as has not had and would not reasonably be expected to have, individually or in the aggregate a Company Material Adverse Effect.

(ii) The Company and its Subsidiaries are in compliance with all applicable Law respecting labor, employment, discrimination in employment, payroll, worker classification, wages and hours, occupational safety and health and employment practices, other than instances of non-compliance that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iii) The list that has been provided by the Company to Parent prior to the date of this Agreement of each employee of the Company and its Subsidiaries setting forth (as applicable) each employee's annual base salary or base wage rate, target annual cash bonus, target long term incentive and other employee data is complete and accurate in all material respects as of the date of this Agreement.

(k) Employee Benefit Matters.

(i) Section 3.01(k)(i) of the Company Disclosure Letter sets forth a complete and accurate list of each material Company Benefit Plan. The Company has made available to Parent correct and complete copies of, to the extent applicable: (A) the current plan document for each material Company Benefit Plan, (B) the most recent annual report on Form 5500 required to be filed with the Department of Labor with respect to each material Company Benefit Plan, (C) the most recent summary plan description for each material Company Benefit Plan, (D) the most recent actuarial reports and financial statements for each material Company Benefit Plan, (E) each trust agreement relating to any material Company Benefit Plan, and (F) the most recent determination or opinion letter, as applicable, for each Qualified Plan.

(ii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (A) each Company Benefit Plan (and any related trust or other funding vehicle) has been established, operated and administered in accordance with its terms and is in compliance with ERISA, the Code and all other applicable Law, (B) all contributions or other amounts payable by the Company or any Commonly Controlled Entity with respect to each Company Benefit Plan in respect of current or prior plan years have been paid or accrued in accordance with GAAP, (C) each Company Benefit Plan (and any related trust) that is intended to be qualified under Section 401(a) of the Code (each, a "Qualified Plan") is the subject of a favorable determination or opinion letter issued by the Internal Revenue Service, and, to the Knowledge of the Company, no condition exists that would reasonably be expected to result in the loss of any such Qualified Plan's qualified status and (D) to the Knowledge of the Company, there has been no non-exempt prohibited transaction (as defined in Section 4975 of the Code or Section 406 of ERISA) or breach of fiduciary duty under Section 404 of ERISA with respect to any Company Benefit Plan.

(iii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, as of the date hereof, (A) no Proceedings (other than routine claims for benefits in the ordinary course of business) are pending or, to the Knowledge of the Company, threatened relating to or otherwise in connection with any Company Benefit Plan or the assets thereof and (B) to the Knowledge of the Company, there are no pending or threatened administrative investigations, audits or other administrative Proceedings by the Department of Labor, the Pension Benefit Guaranty Corporation, the Internal Revenue Service or other Governmental Entity relating to any Company Benefit Plan.

(iv) None of the Company or any Commonly Controlled Entity has, within the past six (6) years, sponsored, maintained, contributed to or been required to maintain or contribute to, or has any liability under, any employee benefit plan (within the meaning of Section 3(3) of ERISA) that is (and no Company

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Benefit Plan is) subject to Section 302 or Title IV of ERISA or Sections 412 or 4971 of the Code, or is otherwise a defined benefit plan (as defined in Section 4001 of ERISA). With respect to any plan set forth in Section 3.01(k)(iv) of the Company Disclosure Letter, the Pension Benefit Guaranty Corporation (the "PBGC") has not instituted Proceedings to terminate any such plan (and, to the Knowledge of the Company, no condition exists that would reasonably be expected to result in such Proceedings being instituted) and the Company and its Commonly Controlled Entities do not have any material liability to the PBGC with respect to such plan other than premium payments required by ERISA. Neither the Company nor any Commonly Controlled Entity has, within the past six (6) years, sponsored, maintained, contributed to or been required to maintain or contribute to, nor has any liability under, any multiemployer plan (as defined in Section 3(37) of ERISA).

(v) The Company has no liability for providing health, medical or life insurance or other welfare benefits after retirement or other termination of employment (other than for continuation coverage required under Section 4980(B)(f) of the Code or other similar applicable Law), except for such liabilities that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. With respect to any plan set forth in Section 3.01(k)(v) of the Company Disclosure Letter, to the Knowledge of the Company, the Company has the right to amend or terminate such plan in its discretion without the consent of any participant.

(vi) None of the execution and delivery of this Agreement, obtaining the Company Requisite Vote or the consummation of the Merger (alone or in conjunction with any other event, including any termination of employment on or following the Effective Time) would reasonably be expected to (A) entitle any current or former director, officer, employee or independent contractor of the Company or any of its Subsidiaries to any compensation or material benefit, (B) accelerate the time of payment or vesting, or trigger any payment or funding, of any compensation or material benefits or trigger any other material obligation under any Company Benefit Plan, (C) result in any material breach or violation of, or material default under, or limit the Company's right to amend, modify, terminate or transfer the assets of, any Company Benefit Plan, (D) directly or indirectly cause the Company to transfer or set aside any assets to fund any benefits, or otherwise give rise to any material liability, under any Company Benefit Plan or (E) result in payments to any "disqualified individual" (as defined for purposes of Section 280G(c) of the Code) which would not be deductible under Section 280G of the Code.

(l) Taxes.

(i) All material Tax Returns required to be filed by or with respect to the Company or any of its Subsidiaries have been timely filed (taking into account any extension of time within which to file) and all such Tax Returns are correct and complete in all material respects.

(ii) All material Taxes of the Company and its Subsidiaries that are required to be paid or discharged, other than Taxes being contested in good faith by appropriate proceedings, have been timely paid and discharged.

(iii) No material deficiency with respect to Taxes has been proposed, asserted or assessed against the Company or any of its Subsidiaries which has not been fully paid or adequately reserved in the SEC Reports filed or furnished by the applicable Reporting Company to the SEC.

(iv) There are no material Tax Liens, other than Permitted Liens, on any asset of the Company or any of its Subsidiaries.

(v) Neither the Company nor any of its Subsidiaries has executed any outstanding waiver of any statute of limitations for the assessment or collection of any material Tax.

(vi) As of the date hereof, no audit or other examination or Proceeding of, or with respect to, any material Tax Return or material amount of Taxes of the Company or any of its Subsidiaries is pending and, between January 1, 2016 and the date hereof, no written notice thereof has been received by the Company or any of its Subsidiaries.

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(vii) None of the Company or any of its Subsidiaries (A) is a party to any material Tax allocation, Tax sharing, or Tax indemnity agreement (other than commercial Contracts the primary purpose of which is not Taxes) or (B) is under an obligation under Treasury Regulation Section 1.1502-6 (or any similar provision of state, local or non-U.S. Law) or as transferee or successor, such that, in each case, the Company or any of its Subsidiaries is, after the date hereof or after the Closing (as the case may be), liable for any material amount of Taxes of another Person (other than the Company or any of its Subsidiaries).

(viii) There are no material closing agreements, private letter rulings, technical advice memoranda or rulings that have been entered into or issued by any Tax authority with respect to the Company or any of its Subsidiaries which are still in effect as of the date of this Agreement.

(ix) Neither the Company nor any of its Subsidiaries has "participated" within the meaning of Treasury Regulation Section 1.6011-4(c)(3)(i)(A) in any "listed transaction" within the meaning of Section 6011 of the Code and the Treasury Regulations thereunder, as in effect and as amended by any guidance published by the Internal Revenue Service for the applicable period.

(x) Each of the Company and its Subsidiaries has properly and timely withheld or collected and timely paid over to the appropriate Governmental Entity (or each is properly holding for such timely payment) all material amounts of Taxes required to be withheld, collected and paid over by applicable Law.

(xi) To the Knowledge of the Company, the Company and its Subsidiaries have complied with the normalization rules described in Section 168(i)(9) of the Code and any other applicable provisions of the Code or the Treasury Regulations thereunder with respect to any "public utility property" (as defined in Section 168(i)(10) of the Code).

(xii) Neither the Company nor any of its Subsidiaries has taken any action or knows of any fact that would reasonably be expected to prevent the Merger from qualifying for the Intended Tax Treatment.

(m) Environmental Matters. Except for those matters that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (i) each of the Company and its Subsidiaries is, and since January 1, 2016 has been, in compliance with all applicable Environmental Law and, as of the date hereof, neither the Company nor any of its Subsidiaries has received any written notice from any Governmental Entity alleging that the Company or any of its Subsidiaries is in violation of, or has any liability under, any Environmental Law, (ii) each of the Company and its Subsidiaries possesses and is in compliance with all Permits required under applicable Environmental Law to conduct its business as currently conducted, and all such Permits are valid and in good standing and neither the Company nor any of its Subsidiaries has received notice from any Governmental Entity seeking to modify, revoke or terminate any such Environmental Permits, (iii) there are no Proceedings pursuant to any Environmental Law pending or, to the Knowledge of the Company, threatened against the Company or any of its Subsidiaries, (iv) there have been no releases of Hazardous Materials at or on any property owned, leased or operated by the Company or any of its Subsidiaries, in each case, in a manner that would reasonably be expected to result in any obligation to conduct any investigation, remediation or other corrective or responsive action by the Company or any of its Subsidiaries and (v) neither the Company nor any of its Subsidiaries is subject to any consent decrees, Orders, settlements or compliance agreements that impose any current or future obligations on the Company and its Subsidiaries under Environmental Law.

(n) Insurance. The Company and its Subsidiaries maintain, or are entitled to the benefits of, insurance in such amounts and against such risks as the Company believes to be customary for companies of a comparable size in the industries in which it and its Subsidiaries operate. Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, all material insurance policies carried by or covering the Company and its Subsidiaries with respect to their business, assets and properties are in full force and effect, and, to the Knowledge of the Company, no notice of cancellation has been given with respect to any such policy.

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(o) Real Property.

(i) Subject, as to enforceability, to bankruptcy, insolvency and other Law of general applicability relating to or affecting creditors' rights and to general equity principles, each Contract under which the Company or any Subsidiary thereof is the tenant, subtenant or occupant (each, a "Company Real Property Lease") with respect to material real property leased, subleased, licensed or otherwise occupied (whether as tenant, subtenant or pursuant to other occupancy arrangements) by the Company or any of its Subsidiaries (collectively, including the improvements thereon, the "Company Leased Real Property") is valid and binding on the Company or the Subsidiary of the Company party thereto, and, to the Knowledge of the Company, each other party thereto, and is in full force and effect, except for such failures to be valid and binding or to be in full force and effect that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. There is no uncured default of any material provision of any Company Real Property Lease by the Company or any of its Subsidiaries or, to the Knowledge of the Company, by any other party thereto, and no event has occurred that with the lapse of time or the giving of notice or both would reasonably be expected to constitute a default thereunder by the Company or any of its Subsidiaries or, to the Knowledge of the Company, by any other party thereto, in each case except for such defaults and events that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(ii) The Company or one of its Subsidiaries has good and valid title to all material real property currently owned by the Company or any of its Subsidiaries (collectively, "Company Owned Real Property") free and clear of all Liens (other than Permitted Liens), except where absence of good and valid title or any such Lien has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iii) Each of the Company and its Subsidiaries has such consents, easements, rights-of-way, permits and licenses with respect to any real property (collectively, "Rights-of-Way") as are sufficient to conduct its business in the manner described, and subject to the limitations, qualifications, reservations and encumbrances contained, in any Applicable Company SEC Report, except for such Rights-of-Way the absence of which has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. All pipelines and electric transmission assets owned or operated by the Company and its Subsidiaries are subject to Rights-of-Way, there are no encroachments or encumbrances or other Rights-of-Way that affect the use thereof and there are no gaps in the Rights-of-Way that are material for such pipelines or electric transmission assets, except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iv) Each of the Company and its Subsidiaries have sufficient rights with respect to their Company Leased Real Property and Company Owned Real Property and under their Rights-of-Way to conduct its business as currently conducted, except where a failure to have such rights would not have and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(p) Intellectual Property, Privacy, and Information Technology.

(i) The Company and its Subsidiaries own or have the right to use all Intellectual Property necessary for the operation of the business of the Company and its Subsidiaries, except where the failure to own or have the right to use such Intellectual Property has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. To the Knowledge of the Company, the operation of the business of the Company and its Subsidiaries does not infringe upon or misappropriate any Intellectual Property of any other Person as of the date of this Agreement, except for such matters that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company and its Subsidiaries have taken commercially reasonable precautions to protect the secrecy and confidentiality of the trade secrets owned by the Company and its Subsidiaries, except where the failure to take reasonable precautions has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

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(ii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (A) to the Knowledge of the Company, the Company has not suffered any security breach of its IT Systems that has caused any loss of data, disruption or damage to the Company's operations, (B) the Company has not experienced any security breaches of personal data or IT Systems that required or would require law enforcement or Governmental Entity notification or any remedial action under applicable Law or any Data Privacy Legal Requirement, (C) to the Knowledge of the Company, since January 1, 2016, there has been no unauthorized access to, or other misuse of, personal data or IT Systems and (D) there are no pending or expected complaints, claims, actions, fines, or other penalties facing the Company in connection with any of the foregoing.

(iii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the Company has security, back-ups, disaster recovery arrangements, and administrative, physical, and technical safeguards in place that are reasonably appropriate for a company in the business in which the Company is engaged and the Company has implemented security patches or upgrades that are reasonably available for the IT Systems where such patches or upgrades are reasonably required to maintain the security of such IT Systems.

(q) Regulatory Matters.

(i) All filings (other than immaterial filings) required to be made by the Company or any of its Subsidiaries since January 1, 2016 with the FERC, the Department of Energy (the "DOE"), the NRC, the FCC, the North American Electric Reliability Corporation (the "NERC"), the SCPSC, the SCORS, the NCUC, the GPSC, the United States Pipeline Hazardous Materials Safety Administration (the "PHMSA") and the United States Department of Transportation (the "DOT"), as the case may be, have been made, including all forms, notices, statements, reports, agreements and all documents, exhibits, amendments and supplements appertaining thereto, including all rates, tariffs and related documents, and all such filings complied, as of their respective dates, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, except for filings the failure of which to make or the failure of which to make in compliance with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(ii) Since January 1, 2016, none of the Company or any of its Subsidiaries has received any written notice or, to the Company's Knowledge, any other communication from the FERC, the DOE, the NRC, the FCC, the NERC, the SCPSC, the SCORS, the NCUC, the GPSC, the PHMSA or the DOT regarding any actual or possible material violation of, or material failure to comply with, any Law.

(iii) To the Knowledge of the Company, except as has not had and would not reasonably be expected to have a material impact on the Company and its Subsidiaries, the operations of the Virgil C. Summer Nuclear Station in Jenkinsville, South Carolina (the "Summer Station"), including the operation of the NND Project and the construction, and cessation of the construction, of such project, are and have been conducted in compliance with applicable health, safety, regulatory and other requirements under applicable Laws.

(iv) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the financial assurance for decommissioning relating to the Summer Station provided to comply with NRC's requirements in 10 CFR 50.75 and 72.30 consists of one or more trusts that are validly existing and in good standing under the Laws of their respective jurisdictions of formation with all requisite authority to conduct their affairs as currently conducted.

(r) Voting Requirements. Assuming the accuracy of the representations and warranties set forth in Section 3.02(n), the affirmative vote of holders of at least two-thirds of the outstanding Company Shares entitled to vote thereon at the Shareholders Meeting or any adjournment or postponement thereof to approve this

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Agreement (the "Company Requisite Vote") is the only vote of the holders of any class or series of capital stock of the Company necessary for the Company to approve this Agreement and approve and consummate the Merger and the other transactions contemplated by this Agreement.

(s) Brokers and Other Advisors. No broker, investment banker, financial advisor or other Person, other than Morgan Stanley & Co. LLC and RBC Capital Markets, LLC, is entitled to any broker's, finder's or financial advisor's fee or commission in connection with the Merger and the other transactions contemplated by this Agreement based upon arrangements made by or on behalf of the Company.

(t) Opinions of Financial Advisors. The Company Board has received the oral opinions of Morgan Stanley & Co. LLC and RBC Capital Markets, LLC to the effect that, as of the date of such opinions and based upon and subject to the various matters, limitations, qualifications and assumptions set forth therein, the Merger Consideration is fair, from a financial point of view, to the holders of Company Shares (other than Cancelled Shares). Signed, true and complete written copies of such opinions will be made available to Parent, which Parent and Merger Sub acknowledge and agree (i) are being provided to Parent for informational purposes only and (ii) may not be relied upon by Parent or Merger Sub.

(u) State Takeover Statutes. Assuming the accuracy of the representations and warranties set forth in Section 3.02(n), the Company Board has taken all action necessary to render inapplicable to this Agreement and the transactions contemplated by this Agreement all potentially applicable state anti-takeover statutes or regulations and any similar provisions in the Company Articles of Incorporation and the Company Bylaws. Assuming the accuracy of the representations and warranties set forth in Section 3.02(n), as of the date of this Agreement, no "fair price", "business combination", "moratorium", "control share acquisition" or other state takeover Law or similar Law (collectively, "Takeover Statutes") enacted by any state will prohibit or impair the consummation of the Merger or the other transactions contemplated by this Agreement.

(v) Information Supplied. None of the information supplied by the Company specifically for inclusion or incorporation by reference in the registration statement on Form S-4 in connection with the issuance by Parent of the aggregate Merger Consideration (the "Form S-4") or the Proxy Statement/Prospectus, at (i) the time the Form S-4 is declared effective, (ii) the date the Proxy Statement/Prospectus is first published or mailed to the holders of Company Shares or (iii) the time of the Shareholders Meeting (except, with respect to the foregoing clauses (i) through (iii), to the extent that any such information is amended or superseded by any subsequent SEC Reports of Parent or the Company), will contain any untrue statement of material fact or omit to state any material fact required to be stated therein or necessary to make the statements therein, in light of the circumstances under which they are made, not misleading.

SECTION 3.02. Representations and Warranties of Parent and Merger Sub. Except (x) as disclosed in the SEC Reports of Parent or its wholly-owned Subsidiaries filed with or furnished to the SEC since January 1, 2016 and publicly available at least twenty-four (24) hours prior to the date of this Agreement (excluding any disclosures set forth in any risk factor section or in any other section to the extent such disclosures are forward-looking statements or are cautionary, predictive or forward-looking in nature) or (y) as set forth in the Parent Disclosure Letter (it being agreed that disclosure of any item in any section or subsection of the Parent Disclosure Letter shall also be deemed disclosed with respect to any other section or subsection of this Agreement to which the relevance of such item is reasonably apparent), Parent and Merger Sub represent and warrant to the Company as follows:

(a) Organization, Standing and Corporate Power. Each of Parent and Merger Sub is a corporation duly incorporated, validly existing and in good standing (where such concept is recognized under applicable Law) under the Laws of the Commonwealth of Virginia, in the case of Parent, and the Laws of the State of South Carolina, in the case of Merger Sub, and has all requisite corporate power and authority to carry on its business as currently conducted and is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the
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ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. Each of Parent's Subsidiaries is a legal entity duly organized, validly existing and in good standing (where such concept is recognized under applicable Law) under the Law of its jurisdiction of organization and has all requisite corporate power and authority to carry on its business as currently conducted, and each of Parent's Subsidiaries is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. Parent has made available to the Company a true and complete copy of the organizational documents of Parent (the "Parent Organizational Documents"), and the comparable organizational documents of Merger Sub, in each case as amended and in effect as of the date of this Agreement.

(b) Subsidiaries. All of the outstanding shares of capital stock of, or other equity interests in, each wholly-owned Subsidiary of Parent have, in all cases, been duly authorized and validly issued and are fully paid, non-assessable and not subject to preemptive rights, and are wholly-owned, directly or indirectly, by Parent free and clear of all Liens, other than transfer restrictions contained in the articles of incorporation, bylaws and limited liability company agreements (or any equivalent constituent documents) of such wholly-owned Subsidiary.

(c) Capital Structure.

(i) The authorized capital stock of Parent consists of 1,000,000,000 Parent Shares and 20,000,000 shares of preferred stock (such preferred stock, the "Parent Preferred Stock"). At the close of business on December 29, 2017, there were (A) 644,571,202 Parent Shares issued and outstanding and (B) no shares of Parent Preferred Stock issued or outstanding. Except as set forth in the immediately preceding sentence, at the close of business on December 29, 2017, no shares of capital stock or other voting securities of Parent were issued or outstanding. Since December 29, 2017 to the date of this Agreement, (x) there have been no issuances by Parent of shares of capital stock or other voting securities of Parent other than pursuant to the exercise or vesting of equity awards under any Parent equity award plans or pursuant to Parent's dividend reinvestment and direct stock purchase plan, in each case, outstanding as of December 29, 2017 and (y) there have been no issuances by Parent of options, warrants, other rights to acquire shares of capital stock of Parent or other rights that give the holder thereof any economic interest of a nature accruing to the holders of Parent Shares. All outstanding Parent Shares are, and all such Parent Shares that may be issued prior to the Effective Time will be when issued, duly authorized, validly issued, fully paid and non-assessable and not subject to preemptive rights.

(ii) No Subsidiary of Parent (it being understood and agreed that, for purposes of this Section 3.02(c)(ii), Subsidiaries of Parent shall not include (x) any benefit plan maintained by Parent or any of its Subsidiaries or (y) any nuclear decommissioning trusts maintained by Parent or any of its Subsidiaries) owns any Parent Shares or other shares of capital stock of Parent. There are no bonds, debentures, notes or other Indebtedness of Parent or of any of its Subsidiaries that give the holders thereof the right to vote (or that are convertible into, or exchangeable for, securities having the right to vote) on any matters on which holders of Parent Shares may vote ("Voting Parent Debt"). Except for any obligations pursuant to this Agreement or as otherwise set forth in Section 3.02(c)(i), as of December 29, 2017, there are no options, warrants, rights (including preemptive, conversion, stock appreciation, redemption or repurchase rights), convertible or exchangeable securities, stock-based performance units, Contracts or undertakings of any kind to which Parent or any of its Subsidiaries is a party or by which any of them is bound (A) obligating Parent or any of its Subsidiaries to issue, deliver or sell, or cause to be issued, delivered or sold, additional shares of capital stock or other securities of, or equity interests in, or any security convertible or exchangeable for any capital stock or other security of, or equity interest in, Parent or any of its wholly-owned Subsidiaries or any Voting Parent Debt, (B) obligating Parent or any of its wholly-owned Subsidiaries to issue, grant or enter into any such option, warrant, right, security, unit, Contract or

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undertaking to declare or pay any dividend or distribution or (C) that give any Person the right to subscribe for or acquire any securities of Parent or any of its wholly-owned Subsidiaries, or to receive any economic interest of a nature accruing to the holders of Parent Shares or otherwise based on the performance or value of shares of capital stock of Parent or any of its wholly-owned Subsidiaries. As of the date of this Agreement, there are no outstanding obligations of Parent or any of its wholly-owned Subsidiaries to repurchase, redeem or otherwise acquire any shares of capital stock or other equity interest, other than pursuant to any Parent equity award plans. There are no voting agreements, voting trusts, shareholders agreements, proxies or other agreements to which Parent or any of its Subsidiaries is bound with respect to the voting of the capital stock or other equity interests of Parent, or restricting the transfer of, or providing registration rights with respect to, such capital stock or equity interests.

(d) Authority; Noncontravention.

(i) Each of Parent and Merger Sub has all requisite corporate power and authority to execute and deliver, and perform its obligations under, this Agreement and to consummate the transactions contemplated by this Agreement, subject, in the case of the Merger, to the delivery by Parent of the written consent, as sole shareholder of Merger Sub, referenced in Section 5.11. The execution, delivery and performance of this Agreement by Parent and Merger Sub and the consummation by Parent and Merger Sub of the transactions contemplated by this Agreement have been duly authorized by all necessary corporate action on the part of each of Parent and Merger Sub, subject, in the case of the Merger, to the delivery by Parent of the written consent, as sole shareholder of Merger Sub, referenced in Section 5.11. This Agreement has been duly executed and delivered by each of Parent and Merger Sub and, assuming the due authorization, execution and delivery by the Company, constitutes a legal, valid and binding obligation of each of Parent and Merger Sub, enforceable against each of Parent and Merger Sub in accordance with its terms, subject, as to enforceability, to bankruptcy, insolvency and other Law of general applicability relating to or affecting creditors' rights and to general equity principles. The board of directors of Parent has duly and validly adopted resolutions approving this Agreement and the transactions contemplated by this Agreement, including the Merger, and the board of directors of Merger Sub has duly and validly adopted resolutions (A) determining that it is in the best interests of Merger Sub and its sole shareholder that Merger Sub enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement on the terms and subject to the conditions set forth in this Agreement, (B) adopting this Agreement and approving the transactions contemplated by this Agreement, including the Merger and (C) recommending that the sole shareholder of Merger Sub approve this Agreement, which resolutions of Parent and Merger Sub, in each case, have not been rescinded, modified or withdrawn in any way.

(ii) The execution, delivery and performance by Parent and Merger Sub of this Agreement do not, and the consummation of the Merger and the other transactions contemplated by this Agreement and compliance with the provisions of this Agreement will not, conflict with, or result in any violation of, or default (with or without notice or lapse of time, or both) under, or give rise to any right (including a right of termination, cancellation or acceleration of any obligation or any right of first refusal, participation or similar right) under, or cause the loss of any benefit under, or result in the creation of any Lien (other than Permitted Liens) upon any of the properties or assets of Parent or Merger Sub or any of their respective Subsidiaries under, any provision of (A) the Parent Organizational Documents or the comparable organizational documents of any of Parent's Subsidiaries, including Merger Sub or (B) subject to the filings and other matters referred to in Section 3.02(d)(iii), (1) any Contract or (2) any Law, in each case, applicable to Parent or Merger Sub or any of their respective Subsidiaries or any of their respective properties or assets, other than, in the case of foregoing clause (B), any such conflicts, violations, defaults, rights, losses or Liens that have not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(iii) No Consent of, or registration, declaration or filing with, or notice to, any Governmental Entity is required to be obtained or made by or with respect to Parent or Merger Sub or any of their respective Subsidiaries in connection with the execution, delivery and performance of this Agreement by Parent and

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Merger Sub or the consummation by Parent and Merger Sub of the transactions contemplated by this Agreement, except for (A) the Regulatory Conditions and any other Consents of or under, and compliance with any other applicable requirements of, (1) the HSR Act, (2) the FERC, (3) the NRC, (4) the FCC, (5) the NCUC, and (6) the GPSC (the items set forth in this clause (A), collectively, the "Parent Regulatory Clearances" and together with the Company Regulatory Clearances, the "Regulatory Clearances"), (B) the filing with the SEC of such reports and other documents (including the filing of the Form S-4) under, and compliance with all other applicable requirements of, the Securities Act or the Exchange Act and the rules and regulations promulgated thereunder and any applicable state securities, takeover and "blue sky" Laws, (C) the filing of the Articles of Merger with the Secretary of State of the State of South Carolina, (D) any filings under, and compliance with all other applicable requirements of, the rules and regulations of the NYSE and (E) such other Consents, registrations, declarations, filings and notices, the failure of which to be obtained or made has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect and would not reasonably be expected to prevent, or materially impair or delay, the consummation of the Merger or any of the other material transactions contemplated by this Agreement.

(e) Applicable Parent SEC Reports; Financial Statements; Undisclosed Liabilities.

(i) Parent and its Subsidiaries have filed or furnished, as applicable, all SEC Reports such companies were required or otherwise obligated to file with or furnish to the SEC since June 30, 2016 (such SEC Reports, the "Applicable Parent SEC Reports"). As of their respective dates of filing, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, the Applicable Parent SEC Reports complied in all material respects with the applicable requirements of the Securities Act, the Exchange Act and the Sarbanes-Oxley Act, as the case may be, and the applicable rules and regulations promulgated thereunder, each as in effect on the date of any such filing. As of the time of filing with the SEC (or, if amended prior to the date of this Agreement, as of the date of such amendment), none of the Applicable Parent SEC Reports so filed contained any untrue statement of a material fact or omitted to state a material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading, except to the extent that the information in such Applicable Parent SEC Reports has been amended or superseded by a later Applicable Parent SEC Report.

(ii) As of their respective dates, the audited and unaudited financial statements (consolidated, as applicable, and including any related notes thereto) of each of Parent and its Subsidiaries, as applicable, included in the Applicable Parent SEC Reports have been prepared in all material respects (except, as applicable, as permitted by Form 10-Q of the SEC or other applicable rules and regulations of the SEC) in accordance with GAAP applied on a consistent basis during the periods involved (except as may be indicated in the notes thereto) and fairly present in all material respects the consolidated financial position of Parent and its Subsidiaries, as applicable, as of the respective dates thereof (taking into account the notes thereto) and the consolidated results of their operations and cash flows for the periods indicated (taking into account the notes thereto) and subject, in the case of unaudited financial statements, to normal year-end adjustments.

(iii) Parent maintains disclosure controls and procedures required by Rule 13a-15(e) or Rule 15d-15(e) under the Exchange Act and such disclosure controls and procedures are effective in all material respects to ensure that information required to be disclosed by Parent in the SEC Reports it files or submits under the Exchange Act is recorded, processed, summarized and reported on a timely basis to the individuals responsible for the preparation of Parent's SEC Reports and other public disclosure documents. Parent maintains internal control over financial reporting required by Rule 13a-15(f) or Rule 15d-15(f) under the Exchange Act and such internal control is effective in all material respects in providing reasonable assurance regarding the reliability of Parent's financial reporting and Parent's preparation of financial statements for external purposes in accordance with GAAP. Parent has disclosed, based on its most recent evaluation prior to the date of this Agreement, to Parent's outside auditors and the audit committee of

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Parent's board of directors (A) any significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that are reasonably likely to adversely affect Parent's ability to record, process, summarize and report financial information and (B) to the Knowledge of Parent, any fraud that involves management or other employees of Parent who have a significant role in Parent's internal control over financial reporting.

(iv) There are no liabilities or obligations of Parent or any of its Subsidiaries of a nature that would be required under GAAP to be reflected or reserved on a financial statement (consolidated, as applicable) of Parent, other than (A) liabilities or obligations reflected or reserved against in such entity's most recent balance sheet (including the notes thereto) included in the Applicable Parent SEC Reports filed prior to the date hereof, (B) liabilities or obligations incurred in the ordinary course of business consistent with past practice since September 30, 2017, (C) liabilities or obligations incurred under or in accordance with this Agreement or in connection with the transactions contemplated by this Agreement and (D) liabilities or obligations that have not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(f) Absence of Certain Changes or Events.

(i) Since January 1, 2017, there have not been any Changes that have had or would reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(ii) Since January 1, 2017, except as contemplated or required by this Agreement, Parent and its wholly-owned Subsidiaries have conducted their respective businesses in all material respects in the ordinary course of business consistent with past practice.

(g) Litigation. Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect, there is no (i) Proceeding pending or, to the Knowledge of Parent, threatened against Parent or any of its Subsidiaries, (ii) to the Knowledge of Parent, pending or threatened material investigation or inquiry by a Governmental Entity of Parent or any of its Subsidiaries and (iii) Order, decree or writ of any Governmental Entity outstanding or, to the Knowledge of Parent, threatened to be imposed against Parent or any of its Subsidiaries.

(h) Compliance with Law. Since January 1, 2016, Parent and each of its Subsidiaries have been in compliance with and have not been in default under or in violation of any applicable Law, except where such non-compliance, default or violation has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. Since January 1, 2016, neither Parent nor any of its Subsidiaries has received any written notice from any Governmental Entity regarding any violation of, or failure to comply with, any Law, except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(i) Taxes.

(i) All material Tax Returns required to be filed by or with respect to Parent or any of its wholly-owned Subsidiaries have been timely filed (taking into account any extension of time within which to file) and all such Tax Returns are correct and complete in all material respects.

(ii) All material Taxes of Parent and its wholly-owned Subsidiaries that are required to be paid or discharged, other than Taxes being contested in good faith by appropriate proceedings, have been timely paid and discharged.

(iii) There are no material Tax Liens, other than Permitted Liens, on any asset of Parent or any of its wholly-owned Subsidiaries.

(iv) Neither Parent nor any of its wholly-owned Subsidiaries has executed any outstanding waiver of any statute of limitations for the assessment or collection of any material Tax.

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(v) As of the date hereof, no audit or other examination or Proceeding of, or with respect to, any material Tax Return or material amount of Taxes of Parent or any of its wholly-owned Subsidiaries is pending and, between January 1, 2016 and the date hereof, no written notice thereof has been received by Parent or any of its wholly-owned Subsidiaries.

(vi) None of Parent or any of its wholly-owned Subsidiaries (A) is a party to any material Tax allocation, Tax sharing, Tax indemnity or similar agreement or (B) is under an obligation under Treasury Regulation Section 1.1502-6 (or any similar provision of state, local or non-U.S. Law) or as transferee or successor, such that, in each case, Parent or any of its wholly-owned Subsidiaries is, after the date hereof or after the Closing (as the case may be), liable for any material amount of Taxes of another Person (other than Parent or any of its wholly-owned Subsidiaries).

(vii) There are no material closing agreements, private letter rulings, technical advice memoranda or rulings that have been entered into or issued by any Tax authority with respect to Parent or any of its wholly-owned Subsidiaries which are still in effect as of the date of this Agreement.

(viii) Neither Parent nor any of its wholly-owned Subsidiaries has "participated" within the meaning of Treasury Regulation Section 1.6011-4(c)(3)(i)(A) in any "listed transaction" within the meaning of Section 6011 of the Code and the Treasury Regulations thereunder, as in effect and as amended by any guidance published by the Internal Revenue Service for the applicable period.

(ix) Neither Parent nor any of its Subsidiaries has taken any action or knows of any fact that would reasonably be expected to prevent the Merger from qualifying for the Intended Tax Treatment.

(j) Regulatory Matters.

(i) All filings (other than immaterial filings) required to be made by Parent or any of its Subsidiaries since January 1, 2016 with the FERC, the DOE, the NRC, and the NERC, as the case may be, have been made, including all forms, notices, statements, reports, agreements and all documents, exhibits, amendments and supplements appertaining thereto, including all rates, tariffs and related documents, and all such filings complied, as of their respective dates, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, except for filings the failure of which to make or the failure of which to make in compliance with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(ii) Since January 1, 2016, none of Parent or any of its wholly-owned Subsidiaries has received any written notice or, to Parent's Knowledge, any other communication from the FERC, the DOE, the NRC or the NERC regarding any actual or possible material violation of, or material failure to comply with, any Law.

(k) No Vote Required. Other than the approval of this Agreement by the sole shareholder of Merger Sub referenced in Section 5.11, no vote or consent of the holders of any class or series of capital stock of Parent or any of its Affiliates is necessary for Parent and Merger Sub to approve this Agreement and approve and consummate the Merger and the other transactions contemplated by this Agreement.

(l) Brokers and Other Advisors. Except for fees or commissions to be paid by Parent, no broker, investment banker, financial advisor or other Person is entitled to any broker's, finder's or financial advisor's fee or commission in connection with the Merger and the other transactions contemplated by this Agreement based upon arrangements made by or on behalf of Parent or Merger Sub.

(m) Ownership and Operation of Merger Sub. The authorized capital stock of Merger Sub consists solely of one thousand (1,000) shares of common stock, without par value, one hundred (100) of which are
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validly issued and outstanding as of the date hereof. All of the issued and outstanding capital stock of Merger Sub is, and at and immediately prior to the Effective Time will be, owned by Parent. Merger Sub has been formed solely for the purpose of engaging in the transactions contemplated by this Agreement and prior to the Effective Time will have engaged in no other business activities and will have no assets, liabilities or obligations of any nature other than those incident to its formation and its entry into this Agreement and the consummation of the Merger and the other transactions contemplated by this Agreement.

(n) Ownership of Shares. None of Parent, Merger Sub or any of their Subsidiaries (it being understood and agreed that, for purposes of this Section 3.02(n), Subsidiaries of Parent and Merger Sub shall not include (x) any benefit plan maintained by Parent or any of its Subsidiaries or (y) any nuclear decommissioning trusts maintained by Parent or any of its Subsidiaries) is, directly or indirectly, a "beneficial owner" (as such term is defined in Rule 13d-3 under the Exchange Act) of any (i) Company Shares, (ii) securities that are convertible into or exchangeable or exercisable for Company Shares, or (iii) any rights to acquire or vote any Company Shares, or any option, warrant, convertible security, stock appreciation right, swap agreement or other security, contract right or derivative position, whether or not presently exercisable, that provides Parent, Merger Sub, or any of their respective Subsidiaries with an exercise or conversion privilege or a settlement payment or mechanism at a price related to the value of Company Shares or a value determined in whole or part with reference to, or derived in whole or part from, the value of the Company Shares, in any case without regard to whether (A) such derivative conveys any voting rights in such securities to such Person, (B) such derivative is required to be, or capable of being, settled through delivery of securities or (C) such Person may have entered into other transactions that hedge the economic effect of such derivative, other than any Company Shares or securities, rights, options, warrants, agreements and derivatives with respect to any Company Shares in an amount equal to, in the aggregate, less than five percent (5%) of the total number of issued and outstanding Company Shares.

(o) Information Supplied. None of the information supplied by Parent specifically for inclusion or incorporation by reference in the Form S-4 or the Proxy Statement/Prospectus, at (i) the time the Form S-4 is declared effective, (ii) the date the Proxy Statement/Prospectus is first published or mailed to the holders of Company Shares or (iii) the time of the Shareholders Meeting (except, with respect to the foregoing clauses (i) through (iii), to the extent that any such information is amended or superseded by any subsequent SEC Reports of Parent or the Company), will contain any untrue statement of material fact or omit to state any material fact required to be stated therein or necessary to make the statements therein, in light of the circumstances under which they are made, not misleading.

(p) Financial Ability. Parent has, and at the Closing Parent will have, sufficient immediately available funds and the financial ability to pay all amounts payable to holders of Company Performance Share Awards and Company RSUs pursuant to Section 2.02 and any repayment or refinancing of then outstanding Indebtedness of the Company or any of its Subsidiaries, which repayment or refinancing is required as a result of the Merger, as set forth in Section 3.02(p) of the Company Disclosure Letter, after taking into account any consents or waivers obtained from any holder of such Indebtedness prior to the Effective Time.

ARTICLE IV

COVENANTS RELATING TO CONDUCT OF BUSINESS

SECTION 4.01. Conduct of Business Pending the Merger.

(a) Conduct of Business by the Company. From the date of this Agreement until the earlier of the Effective Time and the termination of this Agreement in accordance with Article VII, except as otherwise expressly contemplated by this Agreement, set forth in Section 4.01(a) of the Company Disclosure Letter, required by applicable Law, required by a Governmental Entity or with the prior written consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed), (x) the Company shall, and shall cause each of

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its Subsidiaries to, conduct its business in all material respects in the ordinary course consistent with past practice and shall use commercially reasonable efforts to preserve substantially intact its current business organizations, maintain adequate and comparable insurance coverage, and preserve its relationships with its employees, counterparties, customers and suppliers and Governmental Entities with jurisdiction over the Company or any of its Subsidiaries and (y) without limiting the foregoing, the Company shall not, and shall not permit any of its Subsidiaries to:

(i) declare, set aside or pay any dividends on, or make any other distributions (whether in cash, stock or property) in respect of, any of its capital stock, other than (A) regular quarterly cash dividends payable by the Company in respect of Company Shares not in excess of the amount set forth in Section 4.01(a)(i) of the Company Disclosure Letter and (B) dividends or distributions by a Subsidiary of the Company to the Company or to any wholly-owned Subsidiary of the Company;

(ii) split, combine or reclassify any of its capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or issue or authorize the issuance of any other securities in respect of, in lieu of or in substitution for shares of its capital stock, other ownership interests or voting securities, other than transactions solely between or among the Company and its wholly-owned Subsidiaries or between or among the Company’s wholly-owned Subsidiaries;

(iii) purchase, redeem or otherwise acquire any of its or its Subsidiaries’ shares of capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or any rights, warrants or options to acquire any such shares of capital stock, interests or securities, other than (A) the withholding of Company Shares to satisfy Tax obligations or the exercise price with respect to awards granted pursuant to the Company Equity Award Plans or settlement of awards granted pursuant to the Company Equity Award Plans and (B) the acquisition by the Company of awards granted pursuant to the Company Equity Award Plans in connection with the forfeiture or settlement of such awards or rights, in each case, that are outstanding as of the date hereof and in accordance with their terms as of the date hereof or granted after the date hereof in accordance with this Agreement;

(iv) issue, deliver, sell, pledge, dispose of, encumber or subject to any Lien, any shares of its capital stock, other ownership interests or voting securities (other than the issuance of shares by a wholly-owned Subsidiary of the Company to the Company or another wholly-owned Subsidiary of the Company), or any securities convertible into, exercisable or exchangeable for, or any rights, warrants or options to acquire, any such shares of capital stock, interests or voting securities or any “phantom” stock, “phantom” stock rights, stock appreciation rights or stock-based performance units, other than upon the exercise, vesting or settlement of awards granted pursuant to the Company Equity Award Plans that are outstanding as of the date hereof or granted after the date hereof in accordance with this Agreement, in each case, exercised, vested or settled in accordance with their terms;

(v) amend (A) any of the Company Organizational Documents or (B) the comparable organizational documents of any Subsidiary of the Company, other than, in the case of this clause (B), amendments that effect solely ministerial changes to such documents;

(vi) acquire (whether by merger, consolidation, purchase of property or assets (including equity interests) or otherwise) any corporation, partnership or other business organization or division thereof or any material assets or interests in any Person with a value in excess of $50 million in the aggregate, other than transactions solely between or among the Company and its wholly-owned Subsidiaries or between or among the Company’s wholly-owned Subsidiaries;

(vii) sell, license, lease, transfer, assign, divest, cancel, encumber, abandon or otherwise dispose of any of its properties, rights or assets which (A) are material to the Company and its Subsidiaries, taken as a whole, or (B) have a value in excess of $25 million, other than (1) sales, transfers and dispositions of obsolete, non-operating or worthless assets or properties and (2) sales, leases, transfers or other dispositions

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made in connection with (x) any immaterial transactions in the ordinary course of business consistent with past practice or (y) any transactions solely between or among the Company and its wholly-owned Subsidiaries or between or among the Company's wholly-owned Subsidiaries;

(viii) incur, redeem, prepay, defease, cancel, or, in any material respect, modify any indebtedness for borrowed money, issue or sell any debt securities or warrants or other rights to acquire any debt securities of the Company or any of its Subsidiaries, guarantee, assume or endorse or otherwise as an accommodation become responsible for any such indebtedness or any debt securities or other financial obligations of another Person or enter into any "keep well" or other agreement to maintain any financial statement condition of another Person (collectively, "Indebtedness"), other than (A) borrowings under existing revolving credit facilities (or replacements thereof on comparable terms, including in regards to maturity) or commercial paper programs in the ordinary course of business, (B) other than as set forth in the foregoing clause (A) and in Section 4.01(a)(viii) of the Company Disclosure Letter, incurring any Indebtedness in the ordinary course of business (including interest rate swaps on customary commercial terms consistent with past practice) not in excess of $200,000,000, (C) other than as set forth in Section 4.01(a)(viii) of the Company Disclosure Letter, redeeming, prepaying, defeasing, cancelling or modifying any Indebtedness in the ordinary course of business (including interest rate swaps on customary commercial terms consistent with past practice) not to exceed $200,000,000, (D) incurring, redeeming, prepaying, defeasing, cancelling or modifying any Indebtedness among the Company or any of its Subsidiaries, (E) incurring any Indebtedness to replace, renew, extend, refinance or refund any existing Indebtedness in the same principal amount of such existing Indebtedness and upon the maturity of such existing Indebtedness and to the extent such existing Indebtedness is Indebtedness of the Company, on terms that can be redeemed or prepaid at any time upon payment of the outstanding principal amount plus accrued interest without any make whole or similar prepayment penalty, and (F) providing guarantees and other credit support by the Company with respect to the obligations of any of its Subsidiaries; provided, however, no such Indebtedness shall contain any term that would accelerate the payment thereof or require its immediate repayment due to the transactions contemplated by this Agreement;

(ix) settle any claim, investigation or Proceeding with a Governmental Entity or third party, in each case, threatened, made or pending against the Company or any of its Subsidiaries, which (A) provides injunctive relief which is material to the Company or any of its Subsidiaries or (B) requires payment in excess of $10 million in the aggregate, other than the settlement of any claims, investigations or Proceedings made in the ordinary course of business or for an amount (excluding any amounts that are covered by any insurance policies of the Company or its Subsidiaries, as applicable) not in excess of the amount reflected or reserved therefor in the most recent financial statements (or the notes thereto) of the Company included in the Company's SEC Reports; provided, however, that neither the Company nor any of its Subsidiaries shall settle any claim, investigation or Proceeding with a Governmental Entity or third party, in each case, threatened, made or pending against the Company or any of its Subsidiaries relating to or arising out of (A) the construction (or cessation of the construction), abandonment or disposal of nuclear power Units 2 and 3 at the Summer Station, (B) the bankruptcy of Westinghouse Electric Company, LLC (including the settlement agreement entered into with Toshiba Corporation and any Contract relating to the proceeds thereof), or (C) any other aspect of the NND Project (collectively, the "NND Project Litigation") (it being understood and agreed that this proviso shall not apply to (x) the termination of any Contract related to the NND Project so long as such termination results in no additional liability of the Company or any of its Subsidiaries in excess of $5 million in the aggregate or (y) any immaterial amendment of any Contract related to the NND Project) other than as follows:
(a) except as set forth in subclause (b) below, neither the Company nor any of its Subsidiaries shall settle any claim, investigation or Proceeding with a third party who is not a Governmental Entity relating to or arising out of the NND Project Litigation without prior consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed), (b) the Company or its Subsidiaries may, after prior notice to Parent, settle any mechanic liens related to the cessation of construction of the NND Project including those more specifically described as item 1(y) of Section 3.01(g) of the Company Disclosure Letter (it being understood and agreed that the $10 million limitation referred to in the fourth line of this Section 4.01(a)(ix) shall not apply to such settlement of mechanic's liens) and

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(c) neither the Company nor its Subsidiaries may settle any claim, investigation or Proceeding with a Governmental Entity relating to or arising out of the NND Project Litigation without prior consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed);

(x) make or agree to make any capital expenditure in any fiscal year, except (A) for capital expenditures made in accordance with the capital expenditures plan set forth in Section 4.01(a)(x) of the Company Disclosure Letter in an amount not to exceed $50 million in excess of the amounts set forth in such capital expenditure plan during any calendar year, (B) for capital expenditures related to operational emergencies, equipment failures or outages or expenditures that the Company reasonably determines are then necessary to maintain the safety and integrity of any asset or property in response to any unanticipated or unforeseen and subsequently discovered events, occurrences or developments, or (C) as required by Law or a Governmental Entity;

(xi) except as required pursuant to the terms of any Company Benefit Plan or other written agreement, in each case, in effect on the date hereof, (A) grant to any director or officer any increase in compensation or pay, or award any bonuses or incentive compensation, including in the case of any Company officer, any changes associated with promotions or other position changes, regardless of whether such promotions or changes were previously announced, (B) grant to any current or former director, officer or employee any increase in severance, retention or termination pay, (C) grant or amend any equity awards, (D) enter into any new, or modify any existing, employment or consulting agreement with any current or former director or officer or enter into any new, or modify any existing, employment or consulting agreement with any individual consultant pursuant to which the annual base salary of such individual under such agreement exceeds $250,000.00 or the term of which exceeds twelve (12) months, (E) establish, adopt, enter into or amend in any material respect any material collective bargaining agreement or material Company Benefit Plan, (F) take any action to accelerate any rights or benefits under any Company Benefit Plan, or (G) hire or promote any new officer (other than any officer whose hiring or promotion has previously been publicly announced, but that has not yet taken effect as of the date hereof); provided, however, that, other than as set forth in subclause (A), the foregoing shall not restrict the Company or any of its Subsidiaries from entering into or making available to newly hired employees or to employees in the context of promotions based on job performance or workplace requirements, in each case, in the ordinary course of business, plans, agreements, benefits and compensation arrangements (including incentive grants, whether cash or equity, but excluding any individual severance arrangements) that have a value that is consistent with its past practice of making compensation and benefits available to newly hired or promoted employees in similar positions and under similar circumstances;

(xii) other than as required (A) by GAAP (or any interpretation thereof), including pursuant to standards, guidelines and interpretations of the Financial Accounting Standards Board or any similar organization or (B) by a Governmental Entity or Law (including pursuant to any applicable SEC rule or policy), make any change in accounting methods, principles or practices where such changes would reasonably be expected to be material to the Company and its Subsidiaries, taken as a whole;

(xiii) (A) make, change or rescind any material Tax election, any Tax accounting period, or adopt or change any material method of Tax accounting, (B) settle or compromise any material Tax liability or consent to any material claim or assessment or obtain any material ruling relating Taxes, (C) file any amended material Tax Return or (D) enter into any material closing agreement relating to Taxes;

(xiv) other than in the ordinary course of business consistent with past practice, materially amend, modify or terminate, or waive any material rights under, or enter into any Contract which if entered into prior to the date of this Agreement would have been deemed, a Company Material Contract;

(xv) adopt or enter into a plan of complete or partial liquidation, dissolution, merger, consolidation, restructuring, recapitalization or other reorganization, other than the Merger and any other mergers, consolidations, restructurings, recapitalizations or other reorganizations solely between or among the

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Company and its wholly-owned Subsidiaries or between or among the Company's wholly-owned Subsidiaries;

(xvi) materially change or enter into any IT Systems or cyber-security Contracts that are material to the Company and its Subsidiaries (other than routine maintenance and upgrades to existing IT Systems); or

(xvii) authorize any of, or commit or agree to take any of, the foregoing actions prohibited pursuant to clauses (i) through (xvi) of this Section 4.01(a).

(b) Conduct of Business by Parent. From the date of this Agreement until the earlier of the Effective Time and the termination of this Agreement in accordance with Article VII, except as otherwise expressly contemplated by this Agreement, set forth in Section 4.01(b) of the Parent Disclosure Letter, required by applicable Law, required by a Governmental Entity or with the prior written consent of the Company (such consent not to be unreasonably withheld, conditioned or delayed), (x) Parent shall, and shall cause each of the Parent Significant Subsidiaries to, conduct its business in all material respects in the ordinary course of business consistent with past practice and shall use commercially reasonable efforts to preserve substantially intact its current business organizations, maintain adequate and comparable insurance coverage and preserve its relationships with its employees, counterparties, customers and suppliers and Governmental Entities with jurisdiction over Parent or any of the Parent Significant Subsidiaries and (y) without limiting the foregoing, Parent shall not:

(i) declare, set aside or pay any dividends on, or make any other distributions (whether in cash, stock or property) in respect of, any of its capital stock, other than regular quarterly cash dividends payable by Parent in respect of Parent Shares;

(ii) split, combine or reclassify any of its capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or issue or authorize the issuance of any other securities in respect of, in lieu of or in substitution for shares of its capital stock, other ownership interests or voting securities, other than transactions solely between or among Parent and its wholly-owned Subsidiaries;

(iii) purchase, redeem or otherwise acquire any of its or the Parent Significant Subsidiaries' shares of capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or any rights, warrants or options to acquire any such shares of capital stock, interests or securities, other than (A) the withholding of Parent Shares or any of Parent's Subsidiaries' capital stock to satisfy Tax obligations or the exercise price with respect to awards granted pursuant to any of Parent's equity award plans or (B) purchasing, redeeming or acquiring any of Parent's equity awards pursuant to any of Parent's equity award plans;

(iv) except for any Parent Shares issued in an offering for cash at a price no lower than ninety-five percent (95%) of the market price for Parent Shares on the NYSE at the time of such offering, issue, deliver, sell, pledge, dispose of, encumber or subject to any Lien, any shares of its capital stock, other ownership interests or voting securities, or, except for equity units or mandatorily convertible securities issued in an offering for cash with a conversion premium, any securities convertible into, exercisable or exchangeable for, or any rights, warrants or options to acquire, any such shares of capital stock, interests or securities or any "phantom" stock, "phantom" stock rights, stock appreciation rights or stock-based performance units, other than upon the exercise, vesting or settlement of awards granted pursuant to any Parent equity award plans or pursuant to Parent's dividend reinvestment and direct stock purchase plan;

(v) amend (A) any of the Parent Organizational Documents or (B) the comparable organizational documents of any Parent Significant Subsidiary, in each case, in a manner that would materially adversely affect the holders of Company Shares whose Company Shares shall, pursuant to Section 2.01(a), convert in part into Parent Shares at the Effective Time; or

(vi) authorize any of, or commit or agree to take any of, the foregoing actions prohibited pursuant to clauses (i) through (v) of this Section 4.01(b).

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(c) From the date of this Agreement until the earlier of the Effective Time and the termination of this Agreement in accordance with Article VII, neither the Company nor Parent shall take or permit any of their respective Subsidiaries to take any action that would reasonably be expected to prevent, or materially impair or delay, the consummation of the Merger or any of the other transactions contemplated by this Agreement.

SECTION 4.02. Acquisition Proposals.

(a) The Company agrees that, except as permitted by this Section 4.02, neither it nor any of its Subsidiaries, or any of their respective directors or officers, shall, and it shall instruct and use its reasonable best efforts to cause its and its Subsidiaries' employees, investment bankers, attorneys, accountants and other advisors or representatives (collectively, "Representatives") not to, directly or indirectly (i) initiate, solicit or knowingly encourage any Acquisition Proposal or the making of any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (ii) engage in, continue or otherwise participate in any discussions or negotiations regarding any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (iii) furnish or provide any information or data to any Person in connection with any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (iv) otherwise knowingly facilitate any effort or attempt with respect to the foregoing. Any violation of the restrictions set forth in this Section 4.02 by any director, officer or investment banker of the Company or any of its Subsidiaries shall be deemed to be a breach of this Section 4.02 by the Company.

(b) The Company agrees that it and its Subsidiaries and their respective directors, officers, and employees, shall, and it shall instruct and use its reasonable best efforts to cause its and its Subsidiaries' Representatives to, immediately (i) cease and cause to be terminated any solicitation, discussions, negotiations or knowing facilitation or encouragement with any Person that may be ongoing with respect to any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (ii) terminate any such Person's access to any physical or electronic data rooms and (iii) request that any such Person and its Representatives promptly return or destroy all confidential information concerning the Company and its Subsidiaries theretofore furnished thereto by or on behalf of the Company or any of its Subsidiaries, and destroy all analyses and other materials prepared by or on behalf of such Person that contain, reflect or analyze such information, in each case, to the extent required by, and in accordance with, the terms of the applicable confidentiality agreement between the Company and such Person.

(c) The Company shall promptly (but in any event within forty-eight (48) hours) notify Parent in writing of the receipt of any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, any Acquisition Proposal, indicating (i) the identity of the Person making such Acquisition Proposal and (ii) the material terms and conditions of such Acquisition Proposal and providing Parent with the most current version (if any) of such inquiry, indication of interest, proposal or offer and all related material documentation. With respect to any Acquisition Proposal described in the immediately preceding sentence, the Company shall keep Parent reasonably informed, on a prompt basis (but in any event within forty-eight (48) hours of any such event), of (x) any changes or modifications to the terms of any such Acquisition Proposal and (y) any communications from such Person to the Company or from the Company to such Person with respect to any changes or modifications to the terms of any such Acquisition Proposal. Except as required by applicable Law, the Company shall not terminate, amend, modify, waive or fail to enforce any provision of any standstill or similar obligation with respect to any class of equity securities of the Company or any of its Subsidiaries.

(d) Notwithstanding anything to the contrary contained in Section 4.02(a) or Section 4.02(b), prior to the Company Requisite Vote, in response to an unsolicited bona fide written Acquisition Proposal that did not result from a breach of this Section 4.02, if the Company Board determines in good faith (x) after consultation with the Company's financial advisors and outside legal counsel, that such Acquisition Proposal is, or could reasonably be expected to lead to, a Superior Proposal and (y) after consultation with the Company's outside

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legal counsel, that the failure to take such action would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law, the Company may, subject to providing Parent prior notice, (i) furnish or provide information (including non-public information or data) regarding, and afford access to, the business, properties, assets, books, records and personnel of, the Company and its Subsidiaries, to the Person making such Acquisition Proposal and its Representatives; provided, however, that the Company shall as promptly as is reasonably practicable make available to Parent any non-public information concerning the Company or its Subsidiaries that is provided to any Person pursuant to this clause (i) to the extent such information was not previously made available to Parent and (ii) engage in discussions and negotiations with such Person and its Representatives with respect to such Acquisition Proposal; provided, further, that, prior to taking any of the actions set forth in the foregoing clauses (i) or (ii) above, the Person making such Acquisition Proposal has entered into an Acceptable Confidentiality Agreement (it being understood that the negotiation of such Acceptable Confidentiality Agreement shall not be deemed to be a breach of Section 4.02(a) or Section 4.02(b)).

(e) Except as set forth in Section 4.02(f) and Section 4.02(g), the Company shall not, and the Company Board (and each committee thereof) shall not (i) (A) withdraw, change, qualify, withhold or modify, or propose to do any of the foregoing, in a manner adverse to Parent or Merger Sub, the Company Board Recommendation, (B) adopt, approve or recommend, or propose to adopt, approve or recommend, any Acquisition Proposal, (C) fail to include the Company Board Recommendation in the Proxy Statement/Prospectus, (D) fail to recommend against any Acquisition Proposal subject to Regulation 14D promulgated under the Exchange Act in any solicitation or recommendation statement made on Schedule 14D-9 within ten (10) Business Days after Parent so requests in writing, (E) if an Acquisition Proposal or any material modification thereof is made public or sent to the holders of Company Shares, fail to issue a press release that reaffirms the Company Board Recommendation within ten (10) Business Days after Parent so requests in writing or (F) agree or resolve to take any action set forth in the foregoing clauses (A) through (E) (any action set forth in this clause (i), a "Company Adverse Recommendation Change") or (ii) authorize, cause or permit the Company or any of its Affiliates to enter into any letter of intent, memorandum of understanding, agreement in principle, definitive agreement, or other similar commitment that would reasonably be expected to lead to an Acquisition Proposal (other than an Acceptable Confidentiality Agreement) (an "Alternative Acquisition Agreement").

(f) Notwithstanding anything to the contrary in this Agreement, at any time prior to obtaining the Company Requisite Vote, the Company Board may make a Company Adverse Recommendation Change (and, solely with respect to a Superior Proposal, terminate this Agreement pursuant to Section 7.01(c)(i)) if (i) the Company has received a Superior Proposal other than as a result of a breach of this Section 4.02 and the Company Board (or a duly authorized committee thereof) determines in good faith, after consultation with the Company's outside legal counsel, that the failure to make a Company Adverse Recommendation Change in response to the receipt of such Superior Proposal would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law and (ii) (A) the Company provides Parent prior written notice of its intent to make any Company Adverse Recommendation Change or terminate this Agreement pursuant to Section 7.01(c)(i) at least four (4) Business Days prior to taking such action to the effect that, absent any modification to the terms and conditions of this Agreement that would cause the Superior Proposal to no longer be a Superior Proposal, the Company Board has resolved to effect a Company Adverse Recommendation Change or to terminate this Agreement pursuant to Section 7.01(c)(i), which notice shall specify the basis for such Company Adverse Recommendation Change or termination, shall provide the material terms and conditions of such Superior Proposal and shall attach the most current draft of any Alternative Acquisition Agreement, and any other material documents with respect to the Superior Proposal that (x) include any terms and conditions of the Superior Proposal and (y) were not produced by the Company, any of its Subsidiaries or any of its or their Representatives solely for internal purposes, if applicable (a "Notice of Recommendation Change") (it being understood that such Notice of Recommendation Change shall not in itself be deemed a Company Adverse Recommendation Change and that any change in price or material revision or material amendment to the terms of a Superior Proposal, if applicable, shall require a new notice to which the provisions of clauses (A), (B) and (C) of this Section 4.02(f) shall apply *mutatis mutandis* except that, in the case of such a new notice, all references to four (4) Business Days in this Section 4.02(f) shall be deemed to be two (2) Business Days), (B)
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during such four (4) Business Day period, if requested by Parent, the Company shall make its Representatives reasonably available to negotiate in good faith with Parent and its Representatives regarding any modifications to the terms and conditions of this Agreement that Parent proposes to make and (C) at the end of such four (4) Business Day period and taking into account any modifications to the terms of this Agreement proposed by Parent to the Company in a written, binding and irrevocable offer, the Company Board determines in good faith (x) after consultation with the Company's financial advisors and outside legal counsel, that such Superior Proposal still constitutes a Superior Proposal and (y) after consultation with the Company's outside legal counsel, that the failure to make such a Company Adverse Recommendation Change would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law.

(g) Notwithstanding anything to the contrary in this Agreement, other than in connection with an Acquisition Proposal (which shall be governed by Section 4.02(f)), at any time prior to obtaining the Company Requisite Vote, the Company Board may make a Company Adverse Recommendation Change if (i) an Intervening Event occurs and in response thereto the Company Board determines in good faith, after consultation with the Company's outside legal counsel, that the failure to take such action would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law and (ii) (A) the Company provides Parent prior written notice of its intent to make any Company Adverse Recommendation Change at least four (4) Business Days prior to taking such action to the effect that the Company Board has resolved to effect a Company Adverse Recommendation Change, which notice shall specify the basis therefor and include a reasonably detailed description of the Intervening Event, (B) during such four (4) Business Day period, if requested by Parent, the Company shall make its Representatives reasonably available to negotiate in good faith with Parent and its Representatives regarding any modifications to the terms and conditions of this Agreement that Parent proposes to make and (C) at the end of such four (4) Business Day period and taking into account any modifications to the terms of this Agreement proposed by Parent to the Company in a written, binding and irrevocable offer, the Company Board determines in good faith, after consultation with the Company's outside legal counsel, that the failure to make such a Company Adverse Recommendation Change would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law. Each time there is a material change to the facts or circumstances relating to the Intervening Event prior to obtaining the Company Requisite Vote, the Company will be required to deliver to Parent prompt written notice of such material change (which notice shall include a reasonably detailed description of such material change) and the Company will provide Parent with an additional two (2) Business Day period prior to making a Company Adverse Recommendation Change, such period shall begin upon the date of Parent's receipt of the notice of such material change.

(h) Nothing contained in this Section 4.02 or elsewhere in this Agreement shall prohibit the Company or any of its Subsidiaries from (i) complying with its disclosure obligations under U.S. federal or state Law, (ii) making any "stop, look or listen" communication to the shareholders of the Company pursuant to Rule 14d-9(f) promulgated under the Exchange Act (or any similar communications to the shareholders of the Company) or (iii) making any other disclosure to its shareholders if the Company Board determines in good faith after consultation with the Company's outside legal counsel that the failure to make such disclosure would be inconsistent with its fiduciary duties under applicable Law.

ARTICLE V

ADDITIONAL AGREEMENTS

SECTION 5.01. Proxy Statement/Prospectus; Shareholders Meeting.

(a) As soon as reasonably practicable following the date of this Agreement, but in any event within thirty (30) Business Days thereafter, (i) the Company and Parent shall jointly prepare and cause to be filed with the SEC the proxy statement/prospectus (together with any amendment or supplement thereto, the "Proxy Statement/Prospectus"), as part of the Form S-4, that includes (A) a proxy statement of the Company for use in

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the solicitation of proxies for the Shareholders Meeting and (B) a prospectus with respect to the issuance of Parent Shares in the Merger and (ii) Parent shall prepare and cause to be filed with the SEC the Form S-4. The Company and Parent shall use their respective reasonable best efforts to (A) have the Form S-4 declared effective under the Securities Act as promptly as practicable after the Form S-4 is filed, (B) ensure that the Form S-4 and the Proxy Statement/Prospectus complies in all material respects with the applicable provisions of the Securities Act, the Exchange Act and the rules and regulations thereunder and (C) keep the Form S-4 effective for as long as may be reasonably requested in connection with the preparation, filing and distribution of the Form S-4 and the Proxy Statement/Prospectus. As promptly as practicable after the date of this Agreement, each of the Company and Parent will furnish or cause to be furnished to the other party the information relating to itself and its Subsidiaries, and cooperate with the other party, as may reasonably be requested, in connection with the preparation, filing and distribution of the Form S-4 and the Proxy Statement/Prospectus. The Form S-4 and Proxy Statement/Prospectus shall include all information reasonably requested by the parties hereto pursuant to the immediately preceding sentence.

(b) Each party hereto shall promptly notify the other parties of the receipt of any comments of the SEC to the Form S-4 or the Proxy Statement/Prospectus and of any request by the SEC for any amendment or supplement thereto or for additional information in connection therewith. As promptly as practicable after receipt of any such comment or request from the SEC, the party that received such comment or request shall provide the other parties copies of all correspondence between the receiving party and its Representatives, on the one hand, and the SEC, on the other hand, regarding such comments or request. The Company and Parent shall each use its reasonable best efforts to promptly provide responses to the SEC with respect to all comments received on the Form S-4 or the Proxy Statement/Prospectus from the SEC.

(c) Notwithstanding the foregoing, prior to filing the Form S-4 (or any amendment or supplement thereto) or mailing the Proxy Statement/Prospectus (or any amendment or supplement thereto) or responding to any comments of the SEC with respect thereto, each of the Company and Parent shall (i) provide the other party an opportunity to review and comment on such document or response (including the proposed final version of such document or response) and shall consider such comments in good faith and (ii) promptly provide the other party with a copy of any such document or response.

(d) Each of the Company and Parent shall advise the other, promptly after receipt of notice thereof, of the time of effectiveness of the Form S-4, the issuance of any stop order relating thereto or the suspension of the qualification of the Parent Shares to be issued in connection with the consummation of the transactions contemplated by this Agreement for offering or sale in any jurisdiction. Each of the Company and Parent shall use its reasonable best efforts to have any such stop order or suspension lifted, reversed or otherwise terminated. Each of the Company and Parent shall also take any other action required to be taken under the Securities Act, the Exchange Act, any applicable foreign or state securities or “blue sky” laws and the rules and regulations thereunder in connection with the Merger and the issuance of the Parent Shares to be issued in connection with the consummation of the transactions contemplated by this Agreement.

(e) If, prior to the Effective Time, any event occurs with respect to any party hereto or any of its Subsidiaries, or any change occurs with respect to other information supplied by such party for inclusion in the Form S-4 or the Proxy Statement/Prospectus, which is required to be described in an amendment of, or a supplement to, the Form S-4 or the Proxy Statement/Prospectus, such party shall promptly notify the other parties hereto of such event, and the Company and Parent shall cooperate (i) in the prompt filing with the SEC of any necessary amendment or supplement to the Form S-4 or the Proxy Statement/Prospectus so that such documents would not include any misstatement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements made therein, in light of the circumstances under which they are made, not misleading and (ii) to the extent required by Law, in disseminating the information contained in such amendment or supplement to the holders of Company Shares.

(f) Subject to the fiduciary duties of the Company Board under applicable Law, the Company will take, in accordance with applicable Law and the Company Organizational Documents, all action necessary to call, give
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notice of, convene and hold a meeting of holders of Company Shares (the "Shareholders Meeting") as promptly as practicable after the Form S-4 is declared effective under the Securities Act, to consider and vote upon the approval of this Agreement. Subject to Section 4.02, the Company Board shall recommend such approval and shall take all lawful action to solicit and obtain the Company Requisite Vote. Notwithstanding anything to the contrary in this Agreement, the Company may, but shall not be required to, adjourn or postpone the Shareholders Meeting (i) to the extent necessary to ensure that any necessary supplement or amendment to the Proxy Statement/Prospectus (including with respect to an Acquisition Proposal) is provided to the holders of Company Shares a reasonable amount of time in advance of a vote on the approval of this Agreement, (ii) if the Company reasonably believes it is necessary and advisable to do so in order to solicit additional proxies in order to obtain the Company Requisite Vote, (iii) if, as of the time for which the Shareholders Meeting is originally scheduled, there are insufficient Company Shares represented (either in person or by proxy) to constitute a quorum necessary to conduct the business of such meeting or (iv) as required by applicable Law.

(g) Parent shall use its reasonable best efforts to cause to be delivered to the Company two (2) letters from Parent's independent accountants, one dated a date within two (2) Business Days before the date on which the Form S-4 shall become effective and one dated a date within two (2) Business Days before the Closing Date, each addressed to the Company, in form and substance reasonably satisfactory to the Company and customary in scope and substance for comfort letters delivered by independent public accountants in connection with registration statements similar to the Form S-4.

(h) The Company shall use its reasonable best efforts to cause to be delivered to Parent two (2) letters from the Company's independent accountants, one dated a date within two (2) Business Days before the date on which the Form S-4 shall become effective and one dated a date within two (2) Business Days before the Closing Date, each addressed to Parent, in form and substance reasonably satisfactory to Parent and customary in scope and substance for comfort letters delivered by independent public accountants in connection with registration statements similar to the Form S-4.

SECTION 5.02. Filings; Other Actions; Notification.

(a) Subject to the terms and conditions set forth in this Agreement, each of the Company, Parent and Merger Sub shall (and shall cause its respective Subsidiaries to) cooperate and use its respective reasonable best efforts to (i) promptly make any required submissions and filings under applicable Law or to Governmental Entities with respect to the Merger and the other transactions contemplated by this Agreement, (ii) promptly furnish information requested in connection with such submissions and filings to such Governmental Entities or under such applicable Law, (iii) keep the other parties reasonably informed with respect to the status of any such submissions and filings to such Governmental Entities or under such applicable Law, including with respect to: (A) the occurrence or receipt of any Consent under such applicable Law, (B) the expiration or termination of any waiting period, (C) the commencement or proposed or threatened commencement of any investigation, litigation or administrative or judicial action or proceeding under such applicable Law, and (D) the nature and status of any objections raised or proposed or threatened to be raised under such applicable Law with respect to the Merger or the other transactions contemplated by this Agreement, (iv) obtain all Consents and Permits from any Governmental Entity (including the Regulatory Clearances) or any other Person necessary to consummate the transactions contemplated by this Agreement as soon as practicable, and (v) take or cause to be taken all other actions, and do or cause to be done all other things, reasonably necessary to consummate and make effective the Merger and the other transactions contemplated by this Agreement as soon as practicable.

(b) In furtherance and not in limitation of the foregoing: each of the Company, Parent and Merger Sub shall (i) (A) make an appropriate filing of a Notification and Report Form pursuant to the HSR Act with respect to the transactions contemplated by this Agreement as promptly as reasonably practicable following the date of this Agreement (and in any event within fifteen (15) Business Days after the date hereof (unless the parties otherwise agree)), (B) furnish as soon as practicable any additional information and documentary material that may be required or requested pursuant to the HSR Act and (C) use its reasonable best efforts to take, or cause to
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be taken, all other actions consistent with this Section 5.02 necessary to cause the expiration or termination of the applicable waiting periods under the HSR Act (including any extensions thereof) as soon as practicable and (ii) (A) make or cause to be made the appropriate filings (including notice filings) as soon as practicable (and in any event by the date with respect to each such filing set forth in Section 5.02(b) of the Company Disclosure Letter (unless the parties otherwise agree)) with the FERC, the NRC, the FCC, the SCPSC, the NCUC and the GPSC relating to the transactions contemplated by this Agreement, (B) supply as soon as practicable any additional information and documentary material that may be required or requested by the FERC, the NRC, the FCC, the SCPSC, the SCORS, the NCUC and the GPSC, as applicable, in connection with the Regulatory Clearances and (C) use its reasonable best efforts to take or cause to be taken all other actions consistent with this Section 5.02 as necessary to obtain any necessary Consents and Permits from the FERC, the NRC, the FCC, the SCPSC, the NCUC and the GPSC, as applicable, in connection with the Regulatory Clearances as soon as practicable.

(c) In furtherance and not in limitation of the foregoing, as promptly as reasonably practicable following the date of this Agreement, the Company and Parent shall (i) work together in good faith the finalize the terms of the SCPCS Petition and (ii) jointly file the SCPSC Petition. Each of the Company, Parent and Merger Sub shall furnish as soon as practicable any additional information and documentary material that may be required by the SCPSC or any other Government Entity in connection with the SCPSC Petition and use its reasonable best efforts to take, or cause to be taken, all other actions consistent with this Section 5.02 and as set forth in the SCPSC Petition necessary to obtain the SCPSC Petition Approval as soon as practicable.

(d) The Company, Parent and Merger Sub shall, subject to applicable Law relating to the exchange of information: (i) promptly notify the other parties of (and if in writing, furnish the other parties with copies of) any communication to such Person from any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity regarding the filings and submissions described in this Section 5.02 and permit the other parties to review and discuss in advance (and to consider in good faith any comments made by the others in relation to) any proposed written response to any communication from any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity regarding such filings and submissions, (ii) keep the other parties reasonably informed of any developments, meetings or discussions with any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity in respect of any filings, submissions, investigations, or inquiries concerning the transactions contemplated by this Agreement and (iii) not independently participate in any meeting or discussion with any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity in respect of any filings, submissions, investigations or inquiries concerning the transactions contemplated by this Agreement without giving the other party or parties hereto prior notice of such meeting or discussions to the extent it is reasonably practical to do so and, unless prohibited by such third party or Governmental Entity or otherwise not reasonably practical, the opportunity to attend or participate; provided, however, that (x) the Company, Parent and Merger Sub shall be permitted to redact any correspondence, filing, submission or communication prior to furnishing it to the other parties to the extent such correspondence, filing, submission or communication contains competitively or commercially sensitive information, including information relating to the valuation of the transactions contemplated by this Agreement and (y) for the avoidance of doubt, the foregoing clause (iii) shall not prohibit the Company, Parent or Merger Sub from independently participating in meetings and discussions with third parties or Governmental Entities that solely relate to an explanation of the terms of this Agreement, including the conditions set forth in Article VI.

(e) In furtherance and not in limitation of the foregoing, but subject to the other terms and conditions of this Section 5.02, Parent, Merger Sub and the Company agree to take promptly any and all steps necessary to avoid, eliminate or resolve each and every impediment to and obtain all Consents under applicable Laws that may be required by any Governmental Entity (including any Regulatory Clearances and the SCPSC Petition Approval), so as to enable the parties to consummate the Merger and the other transactions contemplated by this Agreement as soon as practicable, including committing to and effecting, by consent decree, hold separate
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orders, trust, or otherwise, (i) selling, licensing, holding separate or otherwise disposing of assets or businesses of Parent or the Company or any of their respective Subsidiaries, (ii) terminating, relinquishing, modifying, or waiving existing relationships, ventures, contractual rights, obligations or other arrangements of Parent or the Company or any of their respective Subsidiaries and (iii) creating any relationships, ventures, contractual rights, obligations or other arrangements of Parent or the Company or any of their respective Subsidiaries (each, a "Remedial Action"); provided, however, that any Remedial Action may, at the discretion of the Company or Parent, be conditioned upon consummation of the transactions contemplated by this Agreement.

(f) In furtherance and not in limitation of the foregoing, but subject to the other terms and conditions of this Section 5.02, in the event that any Proceeding is commenced, threatened or is reasonably foreseeable challenging any of the transactions contemplated by this Agreement and such Proceeding seeks, or would reasonably be expected to seek, to prevent, materially impede or materially delay the consummation of such transactions, Parent shall use reasonable best efforts to take or cause to be taken any and all action, including a Remedial Action, to avoid or resolve any such Proceeding as promptly as practicable. In addition, each of the Company, Parent and Merger Sub shall cooperate with each other and use its respective reasonable best efforts to contest, defend and resist any such litigation, action or proceeding and to have vacated, lifted, reversed or overturned any Order, whether temporary, preliminary or permanent, that is in effect and that prohibits, prevents, delays, interferes with or restricts consummation of the transactions contemplated by this Agreement as promptly as practicable.

(g) From the date hereof until the earlier of the Effective Time and the date this Agreement is terminated pursuant to Article VII, neither Parent, Merger Sub, nor Company shall, nor shall they permit their respective Subsidiaries to, acquire or agree to acquire any rights, assets, business, Person or division thereof (through acquisition, license, joint venture, collaboration or otherwise), if such acquisition would reasonably be expected to materially increase the risk of not obtaining, or would reasonably be expected to prevent or prohibit, or materially impede, interfere with or delay, obtaining, any applicable Consent under applicable Laws (including any Regulatory Clearance and the SCPSC Petition Approval) with respect to the transactions contemplated by this Agreement. Section 5.02(g) of the Company Disclosure Letter sets forth the approach to the coordination of matters related to the Company's pending acquisition described as Item 3 of Section 3.01(f) of the Company Disclosure Letter and matters related to this Agreement.

(h) The Company and its Subsidiaries (as applicable) shall, to the extent reasonably practicable, subject to applicable Law relating to the exchange of information and except as would be in violation of, or result in a waiver or loss of, the attorney-client privilege or work-product doctrine: (i) within 48 hours of receipt thereof, notify Parent of (and if in writing, furnish Parent with copies of) any material communication to the Company or its Subsidiaries from any Governmental Entity related to or arising out of any material claim, hearing, investigation or Proceeding, whether criminal or civil in nature, relating to or arising out of the construction, or cessation of the construction, of nuclear power Units 2 and 3 at the Summer Station or the bankruptcy of Westinghouse Electric Company, LLC (including the settlement agreement entered into with Toshiba Corporation and any Contract relating to the proceeds thereof) (collectively, "Nuclear Litigation") and permit Parent to review and discuss in advance (and consider in good faith any comments made by Parent in relation to) any proposed written response to any material communication from any Governmental Entity related to or arising out of any Nuclear Litigation, (ii) keep Parent reasonably informed of any developments, meetings or discussions with any Governmental Entity related to or arising out of any Nuclear Litigation, and (iii) use good faith efforts to give Parent notice (which notice shall be prior notice to the extent providing prior notice is reasonably practical) of any material meetings or discussions relating to or arising out of any Nuclear Litigation (and consider in good faith any comments or guidance from Parent in relation to such meeting or discussions) and, if appropriate in the Company's reasonable judgment, provide Parent the opportunity to attend or participate in such meetings or discussions.

(i) Notwithstanding anything set forth in this Agreement, Parent and its Affiliates shall not be required to and the Company and its Affiliates shall not be required to, unless conditioned on the Closing, and without the
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prior written consent of Parent (which consent may be withheld at Parent's sole discretion) the Company shall not and shall cause its Subsidiaries not to, in connection with obtaining any Consent or Permit, or with respect to any actions required under this Section 5.02, offer or accept, or agree, commit to agree or consent to, any undertaking, term, condition, liability, obligation, commitment or sanction (including any Remedial Action), that constitutes a Burdensome Condition.

(j) Notwithstanding anything set forth in this Agreement, Parent and its Affiliates shall not be required to and the Company and its Affiliates shall not be required to, unless conditioned on the Closing, and without the prior written consent of Parent (which consent may be withheld at Parent's sole discretion) the Company shall not and shall cause its Subsidiaries not to, in connection with the SCPSC Petition, offer or accept, or agree, commit to agree or consent to, any undertaking, term, condition, liability, obligation, commitment or sanction (including any Remedial Action) that (i) materially changes the proposed terms, conditions, or undertakings set forth in the SCPSC Petition or (ii) significantly changes the economic value of the proposed terms set forth in the SCPSC Petition, in each case, as reasonably determined by Parent in good faith.

SECTION 5.03. Access and Reports; Confidentiality.

(a) Subject to applicable Law relating to the exchange of information, upon reasonable notice, the Company and Parent shall, and shall cause each of their respective Subsidiaries to, afford to the other party's Representatives reasonable access, during normal business hours throughout the period prior to the Effective Time, to its employees, properties, books, contracts and records. During such period, the Company and Parent shall, and shall cause each of their respective Subsidiaries to, furnish promptly to the other party (i) to the extent not publicly available, a copy of each report, schedule, registration statement and other document (A) filed by it during such period pursuant to applicable Law or (B) filed with, furnished to or sent to the SEC, the FERC, the FCC, the NRC, the SCPSC, the SCORS, the NCUC, the GPSC or any other federal or state regulatory agency or commission and (ii) all information concerning its business, properties and personnel as may reasonably be requested by the other party; provided, however, that no investigation pursuant to this Section 5.03(a) shall affect or be deemed to modify any representation or warranty made herein; provided, further, that the foregoing shall not require the Company and Parent to (A) permit any inspection, or to disclose any information, that in the reasonable judgment of such party, would result in the disclosure of any trade secrets of third parties or violate any of its obligations to a third party with respect to confidentiality if the Company or Parent, as applicable, shall have used commercially reasonable efforts to obtain the consent of such third party to such inspection or disclosure, (B) disclose any privileged information of such party or any of its Subsidiaries, (C) permit any invasive environmental testing or sampling at any property or (D) take or allow any action that would unreasonably interfere with such party's or any of its Subsidiaries' business or operations. All requests for information made pursuant to this Section 5.03 shall be directed to the executive officer or other Person designated by the Company or Parent, as applicable. Notwithstanding the foregoing, with respect to Parent and its Subsidiaries, the access to and exchange of information described in this Section 5.03(a) shall be limited to the extent reasonably necessary or related to the consummation of the Merger and the other transactions contemplated by this Agreement.

(b) Each of the Company, Parent and Merger Sub will comply with the terms and conditions of that certain letter agreement, dated October 8, 2017, between Parent and the Company (as may be amended from time to time, the "Confidentiality Agreement"), and will hold and treat, and will cause their respective Representatives to hold and treat, in confidence all documents and information exchanged pursuant to Section 5.03(a) in accordance with the Confidentiality Agreement, which Confidentiality Agreement shall remain in full force and effect in accordance with its terms.

SECTION 5.04. Stock Exchange Delisting and Listing.

(a) Prior to the Closing Date, the Company shall cooperate with Parent and use its reasonable best efforts to take or cause to be taken all actions, and do or cause to be done all things, reasonably necessary, proper

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or advisable on its part under applicable Law and rules and policies of the NYSE to enable the delisting by the Surviving Corporation of the Company Shares from the NYSE and the deregistration of the Company Shares under the Exchange Act as promptly as practicable after the Effective Time and in accordance with applicable Law.

(b) Parent shall use its reasonable best efforts to cause the Parent Shares to be issued in connection with the transactions contemplated by this Agreement to be approved for listing on the NYSE, subject to official notice of issuance, prior to the Closing Date.

SECTION 5.05. Publicity. The initial news release regarding the Merger shall be a joint news release reasonably agreed between Parent and the Company and, except with respect to any action taken pursuant to Section 4.02 or Section 7.01, thereafter the Company and Parent each shall consult with each other prior to issuing, and give each other the opportunity to review and comment upon, any news releases or otherwise making public announcements with respect to the Merger and the other transactions contemplated by this Agreement, except as such party may reasonably conclude may be required by Law or by obligations pursuant to any listing agreement with or rules of any national securities exchange or interdealer quotation service or as may be requested by any Governmental Entity.

SECTION 5.06. Employee Matters.

(a) Following the Effective Time and until December 31, 2019 (the "Continuation Period"), Parent shall provide, or shall cause the Surviving Corporation to provide, the individuals who are employed by the Company or any of its Subsidiaries immediately before the Effective Time and not covered by any collective bargaining agreement (the "Company Non-Union Employees") with (i) annual base compensation no less than the annual base compensation provided to such Company Non-Union Employees immediately prior to the Effective Time, (ii) annual target cash incentive opportunities that are no less than the annual target cash incentive opportunities provided to such Company Non-Union Employees immediately prior to the Effective Time, subject to the satisfaction of performance criteria determined by Parent (consistent with the form and terms and conditions (including performance criteria) of such awards provided to other similarly situated employees of Parent) and other terms and conditions of Parent's annual incentive program, (iii) long-term target incentive award opportunities that are no less than the long-term target incentive award opportunities provided to such Company Non-Union Employees immediately prior to the Effective Time (such long-term incentive awards to be provided in such a form, and subject to such performance and vesting criteria and other terms and conditions, as Parent shall determine, consistent with the form and terms and conditions (including performance criteria) of such awards provided to other similarly situated employees of Parent), (iv) employment within a 50-mile radius from each such Company Non-Union Employee's location of employment immediately prior to the Effective Time and duties and responsibilities similar to what such Company Non-Union Employee had immediately prior to the Effective Time, (v) severance benefits that are no less favorable than those set forth in Section 5.06(a) of the Company Disclosure Letter and (vi) other employee benefits that are substantially comparable in the aggregate to the employee benefits provided to such Company Non-Union Employees immediately prior to the Effective Time. Further Parent shall provide, or shall cause the Surviving Corporation to provide, the individuals who are employed by the Company or any of its Subsidiaries immediately before the Effective Time and who are covered by a collective bargaining agreement with (A) compensation and benefits and other terms and conditions of employment in accordance with the terms of such collective bargaining agreement or any subsequently adopted collective bargaining agreement, as in effect from time to time, and (B) severance benefits that are no less favorable than those set forth in Section 5.06(a) of the Company Disclosure Letter.

(b) Without limiting the generality of Section 5.06(a) but subject to the obligations set forth in Section 5.06(a), from and after the Effective Time, Parent shall, or shall cause the Surviving Corporation to, assume, honor and continue during the Continuation Period or, if later, until all obligations thereunder have been satisfied, all of the Company's employment, severance, retention, termination, deferred compensation, and change in control plans, policies, programs, agreements and arrangements maintained by the Company or any of

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its Subsidiaries, in each case, as in effect at the Effective Time, including with respect to any payments, benefits or rights arising as a result of the transactions contemplated by this Agreement (either alone or in combination with any other event), and Parent or the Surviving Corporation may not amend, modify or terminate any such plan, policy, program, agreement or arrangement unless and solely to the extent permitted under the terms thereof as in effect at the Effective Time or otherwise as required to comply with applicable Law. In addition, to the extent required by the express terms of any Company Benefit Plan, Parent shall, or shall cause the Surviving Corporation to, expressly assume and agree to perform all obligations under and with respect to the terms of each such Company Benefit Plan. Notwithstanding anything to the contrary herein, Parent shall, or shall cause the Surviving Corporation to, maintain without amendment (other than as required to comply with applicable Law) for the duration of the Continuation Period each of the Company Benefit Plans listed on Section 5.06(b) of the Company Disclosure Letter. For avoidance of doubt, Parent shall assume, honor and continue the Company's change in control plans in accordance with the foregoing solely with respect to any payments, benefits or rights arising as a result of the transactions contemplated by this Agreement (either alone or in combination with any other event), and shall not be obligated to provide any additional payments, benefits or rights under such plans in connection with any subsequent change in control of Parent or the Surviving Corporation that may occur after the Merger.

(c) With respect to all plans maintained by Parent, the Surviving Corporation or their respective Subsidiaries in which the individuals who are employed by the Company or any of its Subsidiaries immediately before the Effective Time (the "Company Employees") are eligible to participate after the Closing Date (including any vacation, paid time-off and severance plans) for purposes of determining eligibility to participate, level of benefits and vesting (but not benefit accruals under any defined benefit pension plan), each Company Employee's service with the Company or any of its Subsidiaries (as well as service with any predecessor employer of the Company or any such Subsidiary, to the extent service with the predecessor employer is recognized by the Company or such Subsidiary) shall be treated as service with Parent, the Surviving Corporation or any of their respective Subsidiaries or any Commonly Controlled Entity, in each case, to the extent such service would have been recognized by the Company or its Subsidiaries under analogous Company Benefit Plans prior to the Effective Time; provided, however, that such service need not be recognized to the extent that such recognition would result in any duplication of benefits for the same period of service; and, provided further, that no Company Employee shall be entitled based on such prior credited service or otherwise to participate in any frozen or grandfathered plan or benefit formula of Parent or any of its Subsidiaries that would not be offered to employees first hired by Parent or its Subsidiaries after the Effective Time.

(d) Without limiting the generality of Section 5.06(a), Parent shall, or shall cause the Surviving Corporation to, waive any pre-existing condition limitations, exclusions, actively-at-work requirements and waiting periods under any welfare benefit plan maintained by Parent, the Surviving Corporation or any of their respective Subsidiaries in which Company Employees (and their eligible dependents) will be eligible to participate from and after the Effective Time, except to the extent that such pre-existing condition limitations, exclusions, actively-at-work requirements and waiting periods would not have been satisfied or waived under the comparable Company Benefit Plan immediately prior to the Effective Time; provided, however, that in the case of an insured plan, such waivers shall be made only to the extent the insurer consents thereto, and Parent and the Surviving Corporation shall use commercially reasonable efforts to obtain such consent. Parent shall, or shall cause the Surviving Corporation to, recognize the dollar amount of all co-payments, deductibles and similar expenses incurred by each Company Employee (and his or her eligible dependents) during the calendar year or plan year in which the Effective Time occurs for purposes of satisfying such year's deductible and co-payment limitations under the relevant welfare benefit plans in which they will be eligible to participate from and after the Effective Time; provided, however, that in the case of an insured plan, such amounts shall be taken into account only to the extent the insurer consents thereto, and Parent and the Surviving Corporation shall use commercially reasonable efforts to obtain such consent.

(e) The provisions of this Section 5.06 are solely for the benefit of the parties to this Agreement, and no other Person (including any current or former employee of the Company or its Subsidiaries or any beneficiary or

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dependent thereof) shall be regarded for any purpose as a third-party beneficiary of this Section 5.06, and no provision of this Section 5.06 shall create such rights in any such Persons. Except as set forth in Section 5.06(b), no provision of this Agreement shall be construed (i) as a guarantee of continued employment of any employee of the Company or its Subsidiaries, (ii) to prohibit Parent or its Subsidiaries (including the Surviving Corporation) from having the right to terminate the employment of any such employee, (iii) to require Parent or its Subsidiaries to continue to pay or provide any such employee any compensation or benefits after such termination of employment, other than any severance benefits that may be provided pursuant to Section 5.06(a)(v); (iv) to permit the amendment, modification or termination of any Company Benefit Plan or employee benefit plan of Parent or its Subsidiaries (in each case solely to the extent any such amendment, modification or termination is prohibited in accordance with the terms of the applicable plan) or (v) as an amendment or modification of the terms of any Company Benefit Plan or employee benefit plan or Parent or its Subsidiaries.

SECTION 5.07. Expenses. Except as set forth in Section 5.09(c), whether or not the Merger is consummated, all costs and expenses incurred in connection with this Agreement and the Merger and the other transactions contemplated by this Agreement shall be paid by the party incurring such expenses.

SECTION 5.08. Indemnification; Directors' and Officers' Insurance.

(a) From and after the Effective Time, Parent shall indemnify and hold harmless, to the fullest extent permitted under applicable Law, each present and former director and officer of the Company and its Subsidiaries (in each case, when acting in such capacity) (collectively, the "Indemnified Parties") from and against any and all costs and expenses (including reasonable attorneys' fees), judgments, fines, losses, claims, damages and liabilities (collectively, "Costs") incurred in connection with any Proceeding or investigation, whether civil, criminal, administrative or investigative, arising out of or pertaining to matters existing or occurring at or prior to the Effective Time, including the transactions contemplated by this Agreement. From and after the Effective Time, Parent shall advance expenses to each Indemnified Party claiming indemnification pursuant to this Section 5.08 as incurred to the fullest extent permitted under applicable Law; provided, however, that such Indemnified Party provides an undertaking to repay such advances if it is ultimately determined that such Indemnified Party is not entitled to such indemnification.

(b) From and after the Effective Time, Parent shall cause the Surviving Corporation to honor the provisions regarding (i) exculpation of directors, (ii) limitation of liability of directors and officers, (iii) advancement of expenses and (iv) indemnification, in each case, contained in the Company Organizational Documents (as in effect as of the date hereof), the comparable organizational documents of any of the Company's Subsidiaries (as in effect as of the date hereof) or any indemnification Contract set forth in Section 5.08(b) of the Company Disclosure Letter between the applicable Indemnified Party and the Company or any of its Subsidiaries existing immediately prior to the Effective Time (it being understood and agreed that, for the avoidance of doubt and without limiting the generality of the foregoing, the foregoing obligation of Parent shall apply with respect to, and remain in full force and effect as to any pending or future claim, hearing, investigation or Proceeding relating to or arising out of the construction, or cessation of the construction, of nuclear power Units 2 and 3 at the Summer Station or the bankruptcy of Westinghouse Electric Company, LLC (including the settlement agreement entered into with Toshiba Corporation and any Contract relating to the proceeds thereof)). For a period of three (3) years following the Effective Time, Parent shall cause the Surviving Corporation and its Subsidiaries not to amend, replace or otherwise modify the provisions regarding (A) exculpation of directors, (B) limitation of liability of directors and officers, (C) advancement of expenses and (D) indemnification, in each case, contained in their respective organizational documents; provided, however, that such three (3) year period shall be extended for so long as any Proceeding is pending or asserted against an Indemnified Party that implicates the rights set forth in the foregoing clauses (A) through (D); provided, further, that such prohibition on amendments, replacements and other modifications shall not apply to amendments, replacements and other modifications that are prospective in their application and exclude any effect on the Indemnified Parties.
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(c) From and after the Effective Time, Parent shall cause the Surviving Corporation to maintain for a period of at least six (6) years following the Effective Time directors' and officers' liability insurance and fiduciary liability insurance policies (collectively, "D&O Insurance") from an insurance carrier with the same or better credit rating as the Company's current insurance carrier with benefits, levels of coverage and terms and conditions at least as favorable as the Company's D&O Insurance existing immediately prior to the Effective Time with respect to matters existing or occurring at or prior to the Effective Time, including for acts or omissions in connection with this Agreement and the consummation of the transactions contemplated by this Agreement. Notwithstanding the foregoing, in no event shall Parent or the Surviving Corporation be required to expend for such D&O Insurance coverage an annual premium amount greater than three hundred percent (300%) of the aggregate amount of the annual premiums currently paid by the Company for D&O Insurance immediately prior to the Effective Time (such aggregate amount of premiums currently paid, the "Maximum Annual Premium"). If the annual premiums of such D&O Insurance coverage exceed the Maximum Annual Premium, Parent and the Surviving Corporation shall obtain a policy with as much coverage as reasonably available for an annual cost not exceeding the Maximum Annual Premium.

(d) Notwithstanding Section 5.08(c), the Company may in its sole discretion obtain, prior to the Effective Time, six (6) year pre-paid "tail" insurance coverage, at an aggregate cost no greater than six times the Maximum Annual Premium, providing for D&O Insurance not materially less favorable than that described in Section 5.08(c). If the Company has obtained such policy pursuant to this Section 5.08(d), Parent will cause such policy to be maintained in full force and effect for its full term and cause all obligations thereunder to be honored by the Surviving Corporation, and Parent will have no further obligation to purchase or pay for insurance pursuant to Section 5.08(c).

(e) If Parent, the Surviving Corporation or any of their respective successors or assigns (i) consolidates or merges with or into any other Person and is not the continuing or surviving corporation or entity of such consolidation or merger or (ii) transfers all or substantially all of its properties and assets to any Person, then, and in each such case, proper provisions shall be made so that the successors and assigns of Parent or the Surviving Corporation, as applicable, shall assume and comply with all of the obligations applicable to Parent or the Surviving Corporation, respectively, set forth in this Section 5.08.

(f) The provisions of this Section 5.08 are intended to be for the benefit of, and shall be enforceable by, each of the Indemnified Parties. The obligations of Parent and the Surviving Corporation in this Section 5.08 may not be terminated or modified in any manner that adversely affects any Indemnified Party without the consent of such Indemnified Party. Parent will honor, guaranty and stand as surety for, and will cause the Surviving Corporation and its Subsidiaries and successors to honor and comply with, the covenants contained in this Section 5.08.

(g) The rights of the Indemnified Parties under this Section 5.08 shall be in addition to, and not in limitation of, any rights such Indemnified Parties may have under the Company Organizational Documents or any of the comparable organizational documents of any of the Company's Subsidiaries, or under any applicable Contracts or Law.

SECTION 5.09. Financing.

(a) The Company shall, and shall cause its Subsidiaries to, (i) provide commercially reasonable assistance with the preparation of rating agency presentations and lender, underwriter and initial purchaser presentations, offering memoranda and prospectuses and any discussions regarding the business, financial statements, and management discussion and analysis of the Company and its Subsidiaries, all for use in connection with the financing activities of Parent, including any registration statement filed with the SEC where Parent determines that the inclusion of such information is required or desirable, and (ii) request that its independent accountants provide customary and reasonable assistance to Parent or any of its Subsidiaries, as applicable, in connection with providing customary comfort letters in connection with the financing activities of

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Parent; provided, further, that nothing in this Agreement shall require the Company to cause the delivery of (A) legal opinions or reliance letters or any certificate as to solvency or any other certificate necessary for such financing activities, other than as allowed by the preceding clause (ii), (B) any audited financial information or any financial information prepared in accordance with Regulation S-K or Regulation S-X under the Securities Act or any financial information in a form not customarily prepared by the Company with respect to any period or (C) any financial information with respect to a month or fiscal period that has not yet ended or has ended less than forty-five (45) days prior to the date of such request.

(b) Notwithstanding anything to the contrary contained in this Agreement (including this Section 5.09): (i) nothing in this Agreement (including this Section 5.09) shall require any such cooperation set forth in Section 5.09(a) to the extent that it would require the Company, any of its Subsidiaries or any of their respective Affiliates or Representatives to (A) pay any commitment or other fees, reimburse any expenses or otherwise incur any liabilities or give any indemnities prior to the Effective Time, (B) provide any cooperation that would unreasonably interfere with the ongoing business or operations of the Company, any of its Subsidiaries or any of their respective Affiliates or Representatives, (C) enter into or approve any agreement or other documentation effective prior to the Effective Time or agree to any change or modification of any existing agreement or other documentation that would be effective prior to the Effective Time, (D) require the Company to provide *pro forma* financial statements or *pro forma* adjustments reflecting the financing activities of Parent or any description of all or any component of such financing activities (it being understood that the Company shall use reasonable best efforts to assist in preparation of *pro forma* financial adjustments to the extent otherwise relating to the Company and required by the financing activities of Parent), (E) require the Company or the Subsidiaries of the Company to provide *pro forma* financial statements or *pro forma* adjustments reflecting transactions contemplated or required hereunder (it being understood that the Company shall use reasonable best efforts to assist in preparation of *pro forma* financial adjustments to the extent otherwise relating to the Company and required by the financing activities of Parent), (F) provide any cooperation or take any action that, in the reasonable judgment of the Company, would result in a violation of any confidentiality agreement or material agreement or the loss of any attorney-client or other similar privilege, (G) make any representation or warranty in connection with the financing activities of Parent or the marketing or arrangement thereof, (H) provide any cooperation, or take any action, that would cause any representation or warranty in this Agreement to be breached or any condition to the Closing set forth in this Agreement to fail to be satisfied or (I) cause the Company, any of its Subsidiaries or any of their respective boards of directors (or equivalent bodies) to approve or authorize the financing activities of Parent, and (ii) no action, liability or obligation (including any obligation to pay any commitment or other fees or reimburse any expenses) of the Company, any of its Subsidiaries or any of their respective Affiliates or Representatives under any certificate, agreement, arrangement, document or instrument relating to the financing activities of Parent shall be effective until the Effective Time.

(c) Parent shall (i) promptly reimburse the Company for all reasonable and out-of-pocket costs or expenses (including reasonable and documented costs and expenses of counsel and accountants) incurred by the Company, any of its Subsidiaries and any of their respective Representatives in connection with any cooperation provided for in Section 5.09(a) and (ii) indemnify and hold harmless the Company, each of its Subsidiaries and each of their respective Representatives against any claim, loss, damage, injury, liability, judgment, award, penalty, fine, Tax, cost (including cost of investigation), expense (including fees and expenses of counsel and accountants) or settlement payment incurred as a result of, or in connection with, any cooperation provided for in Section 5.09(a) or the financing activities of Parent and any information used in connection therewith, unless the Company acted in bad faith or engaged in willful misconduct and other than in the case of fraud.

(d) Without limiting the generality of the foregoing, promptly following Parent's request, the Company shall deliver to each of the lenders with respect to the Indebtedness set forth in Section 5.09(d) of the Parent Disclosure Letter (the "Existing Loan Lenders") a notice (an "Existing Loan Notice") prepared by Parent, in form and substance reasonably acceptable to the Company, notifying each of the Existing Loan Lenders of this Agreement and the contemplated Merger. At Parent's election, the Existing Loan Notice with respect to one or more of the Existing Loan Lenders may include a request for a consent, in form and substance reasonably

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acceptable to the Company (an "Existing Loan Consent"), to (i) the consummation of the Merger and the other transactions contemplated by this Agreement, and (ii) certain modifications of (or waivers under or other changes to) any agreement or documentation relating to the Company's or its Subsidiaries', as applicable, relationship with such Existing Loan Lender; provided, however, that no such modifications, waivers or changes shall be effective prior to the Effective Time.

(e) Parent and Merger Sub acknowledge and agree that the obtaining of any Existing Loan Consent is not a condition to the Closing.

SECTION 5.10. Rule 16b-3. Prior to the Effective Time, each of the Company and Parent shall take such steps as may be reasonably necessary or advisable to cause (a) any dispositions of Company equity securities (including derivative securities) pursuant to the transactions contemplated by this Agreement by each individual who is subject to the reporting requirements of Section 16(a) of the Exchange Act with respect to the Company to be exempt under Rule 16b-3 promulgated under the Exchange Act and (b) any acquisitions of Parent equity securities (including derivative securities) pursuant to the transactions contemplated by this Agreement by each individual who may become subject to the reporting requirements of Section 16(a) of the Exchange Act with respect to Parent to be exempt under Rule 16b-3 promulgated under the Exchange Act.

SECTION 5.11. Parent Consent. Within twenty-four (24) hours after the execution of this Agreement, Parent shall execute and deliver, in accordance with Chapter 11 of the SCBCA and in its capacity as the sole shareholder of Merger Sub, a written consent approving this Agreement.

SECTION 5.12. Merger Sub and Surviving Corporation Compliance. Parent shall cause Merger Sub or the Surviving Corporation, as applicable, to comply with all of its respective obligations under this Agreement, and prior to the Effective Time, Merger Sub shall not engage in any activities of any nature except as provided in or in furtherance of, or contemplated by this Agreement.

SECTION 5.13. Takeover Statutes. If any Takeover Statute is or may become applicable to the Merger or the other transactions contemplated by this Agreement, Parent, Merger Sub, the Company and the Company Board shall use reasonable best efforts to take such actions as are necessary so that such transactions may be consummated as promptly as practicable on the terms contemplated by this Agreement and otherwise act to eliminate or minimize the effects of such Takeover Statute on such transactions.

SECTION 5.14. Control of Operations. Without limiting any party's rights or obligations under this Agreement, the parties hereto understand and agree that (a) nothing contained in this Agreement will give any party hereto, directly or indirectly, the right to control, direct or influence any other party's operations prior to the Effective Time and (b) prior to the Effective Time, each party will exercise, consistent with the terms and conditions of this Agreement, complete control and supervision over its operations.

SECTION 5.15. Resignation of Directors. The Company will cause each of the directors of the Company to submit at the Closing a letter of resignation in form reasonably satisfactory to Parent and effective as of the Effective Time. Notwithstanding the foregoing, the Company will not be in breach of this Section 5.15 if it fails to obtain the resignation of any such director if Parent will have the power, directly or indirectly, to remove any such Person from his or her position as a director of the Company without cause immediately after the Effective Time with no liability in excess of $500,000 in the aggregate.

SECTION 5.16. Additional Matters. Parent hereby confirms that, subject to the occurrence of the Effective Time, it:

(a) intends to maintain South Carolina Electric & Gas Company's corporate headquarters in Cayce, South Carolina;

(b) will make a good faith commitment to give the employees of the Company and its Subsidiaries due and fair consideration for other employment and promotion opportunities within the larger Parent organization,

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both inside and outside of South Carolina, to the extent any employment positions are re-aligned, reduced or eliminated in the future as a result of the Merger;

(c) intends that Parent's board of directors will take all necessary action as soon as practical after the Effective Time to appoint a mutually agreeable current member of the Company Board or the Company's executive management as a director to serve on Parent's board of directors; and

(d) intends to increase the Company's historic level of corporate contributions to charities identified by the Company's leadership by $1,000,000.00 per year for at least five (5) years after the Effective Time and to maintain or increase historic levels of community involvement, low income funding and economic development efforts in the Company's current operating area.

SECTION 5.17. Shareholder Litigation. The Company shall advise Parent promptly in writing of any Proceeding brought by a holder of Company Shares or any other Person against the Company or its directors or officers arising out of or relating to this Agreement or the transactions contemplated by this Agreement (the "Shareholder Litigation") and shall keep Parent reasonably informed regarding any such matter. The Company shall not settle any such shareholder litigation without Parent's consent, not to be unreasonably withheld or delayed.

SECTION 5.18. Advice of Changes. Each of Parent and the Company will, to the extent not in violation of applicable Law, promptly advise the other of any Change of which it has Knowledge, (a) having or reasonably likely to have, individually or in the aggregate, a Parent Material Adverse Effect or a Company Material Adverse Effect, as the case may be, or (b) that would or would be reasonably likely to cause or constitute a material breach of any of its representations, warranties or covenants contained in this Agreement; provided, however, that (i) no such notification will operate as a waiver of or otherwise affect the representations, warranties or covenants of the parties or the conditions to the obligations of the parties under this Agreement, (ii) the delivery of any notice pursuant to this Section 5.18 shall not limit or otherwise affect the remedies available under this Agreement to the party receiving such notice and (iii) a failure to comply with this Section 5.18 shall not constitute the failure of any condition set forth in Article VI.

SECTION 5.19. Certain Tax Matters.

(a) Each of the parties shall use its reasonable best efforts to cause the Merger to qualify for the Intended Tax Treatment. None of the parties shall (and each of the parties shall cause their respective Subsidiaries not to) take any action (or fail to take any action) if taking (or failing to take) such action could reasonably be expected to cause the Merger to fail to qualify for the Intended Tax Treatment. The parties shall consider in good faith such amendments to this Agreement as may be reasonably required to cause the Merger to qualify for the Intended Tax Treatment.

(b) Each of the parties shall use its reasonable best efforts to obtain the Tax opinions to be attached as exhibits to the Proxy Statement/Prospectus and the Form S-4, including by (i) delivering to Morgan, Lewis & Bockius LLP and Mayer Brown LLP, prior to the filing of the Proxy Statement/Prospectus and the Form S-4, Tax representation letters in substantially the forms set forth in Section 5.19(b) of the Parent Disclosure Letter and Section 5.19(b) of the Company Disclosure Letter, respectively, and (ii) delivering to Morgan, Lewis & Bockius LLP and Mayer Brown LLP, dated and executed as of the Closing Date, Tax representation letters in substantially the forms set forth in Section 5.19(b) of the Parent Disclosure Letter and Section 5.19(b) of the Company Disclosure Letter, respectively. Each of the parties shall use its reasonable best efforts not to, and not permit any of its Affiliates to, take or cause to be taken any action that would cause to be untrue (or fail to take or cause not to be taken any action which inaction would cause to be untrue) any of the representations, warranties and covenants made to counsel in the Tax representation letters described in this Section 5.19(b).

(c) This Agreement is intended to constitute, and the parties hereto adopt this Agreement as, a "plan of reorganization" for purposes of Sections 354, 361 and 368 of the Code. The parties shall treat the Merger as

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a "reorganization" within the meaning of Section 368(a) of the Code for United States federal, state and other relevant Tax purposes.

ARTICLE VI

CONDITIONS

SECTION 6.01. Conditions to Each Party's Obligation to Effect the Merger. The respective obligation of each party hereto to effect the Merger is subject to the satisfaction or (to the extent permitted by Law) waiver at or prior to the Closing of each of the following conditions:

(a) Shareholder Approval. This Agreement shall have been duly approved by holders of Company Shares constituting the Company Requisite Vote;

(b) Orders. No Governmental Entity of competent jurisdiction shall have enacted, entered, promulgated or enforced any Law, executive order, ruling, judgment, injunction or other order (collectively, "Orders") that is in effect and restrains, enjoins, prevents or otherwise prohibits the consummation of the Merger or makes the consummation of the Merger illegal;

(c) Regulatory Conditions. Each of the conditions set forth in Section 6.01(c) of the Company Disclosure Letter with respect to the Consents described therein (the "Regulatory Conditions") shall have been satisfied;

(d) Approval of SCPSC Petition. The issuance by the SCPSC of an Order approving the SCPSC Petition (other than the request for the SCPSC to take the actions contemplated by Section 6.02(g), which actions are addressed in Section 6.02(g)), unless otherwise consented to by Parent in its sole discretion, without any (i) material changes to the proposed terms, conditions, or undertakings set forth in Section 3 of the key terms summarized in Appendix A attached to this Agreement and incorporated in the SCPSC Petition or (ii) a significant change to the economic value of proposed terms set forth in Section 3 of the key terms summarized in Appendix A attached to this Agreement and incorporated in the SCPSC Petition, in each case as reasonably determined by Parent in good faith (the "SCPSC Petition Approval") (it being understood and agreed that the condition set forth in this Section 6.01(d) shall be satisfied upon the issuance of such Order by the SCPSC without regard to any rehearing or appeals process (including the filing of any motion for reconsideration or petition for judicial review), or other judicial or administrative process, subsequent to the initial issuance of such Order);

(e) Listing. The Parent Shares to be issued in connection with the transactions contemplated by this Agreement shall have been approved for listing on the NYSE, subject to official notice of issuance; and

(f) Form S-4. The Form S-4 shall have been declared effective under the Securities Act and shall not be subject to any stop order or Proceeding seeking a stop order.

SECTION 6.02. Additional Conditions to Obligations of Parent and Merger Sub. The obligations of Parent and Merger Sub to effect the Merger are further subject to the satisfaction or (to the extent permitted by Law) waiver at or prior to the Closing of each of the following conditions:

(a) Representations and Warranties. (i) Each of the representations and warranties of the Company set forth in Section 3.01 (except for those contained in Section 3.01(c), Section 3.01(d)(i), Section 3.01(f)(i), Section 3.01(r) and Section 3.01(s)) shall be true and correct in all respects (disregarding all qualifications or limitations as to "materiality", "Company Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in
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which case such representation or warranty shall be true and correct only as of such specified date), except where the failure of such representations and warranties to be so true and correct has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (ii) each of the representations and warranties of the Company set forth in Section 3.01(c) shall be true and correct in all respects (except for de minimis inaccuracies) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date), (iii) each of the representations and warranties of the Company set forth in Section 3.01(d)(i) and Section 3.01(s) shall be true and correct in all material respects (disregarding all qualifications or limitations as to "materiality", "Company Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date) and (iv) each of the representations and warranties of the Company set forth in Section 3.01(f)(i) and Section 3.01(r) shall be true and correct in all respects as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date);

(b) Performance of Obligations of the Company. The Company shall have performed in all material respects all obligations required to be performed by it under this Agreement on or prior to the Closing Date;

(c) Certificate. Parent shall have received a certificate of the Chief Executive Officer or the Chief Financial Officer of the Company, certifying that the conditions set forth in Section 6.02(a) and Section 6.02(b) have been satisfied;

(d) Absence of Burdensome Condition. No Regulatory Clearance, other approval of a Governmental Entity or other Consent, in each case in connection with the Merger, or Order related to any of the foregoing, shall impose or require any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions, or any structural or remedial actions (including a Remedial Action), that constitute a Burdensome Condition;

(e) No MAE. Since the date of this Agreement, there shall not have occurred any Change or Changes that have or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect;

(f) No Actions Affecting SCPSC Petition. No Governmental Entity of competent jurisdiction shall have enacted any Order and no Change in Law (including no Change to the BLRA or the South Carolina Public Utility Laws) shall have been enacted, in each case which imposes any condition that would reasonably be expected to result in a (i) material change to the proposed terms, conditions, or undertakings set forth in the SCPSC Petition or (ii) a significant change to the economic value of the proposed terms set forth in the SCPSC Petition, in each case as reasonably determined by Parent in good faith;

(g) SCPSC Determination. The SCPSC shall have (i) approved the Merger with no material Changes to the terms of the Merger, (ii) made a finding that the Merger is in the public interest or (iii) made a finding that there is an absence of harm to South Carolina rate payers as a result of the Merger; and

(h) No Change in Law. Since the date of this Agreement, there shall not have occurred any (i) substantive Change in any applicable Law or any Order with respect to the BLRA, as in effect on the date of this Agreement, which has or would reasonably be expected to have an adverse effect on the Company or any of its Subsidiaries or (ii) substantive Change in any applicable Law or any Order with respect to any other South Carolina Public Utility Law, as in effect as of the date of this Agreement, which has or would reasonably be expected to have an adverse effect on the Company or any of its Subsidiaries (such Changes as set forth in (i) and (ii), the "SC Law Changes").

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SECTION 6.03. Additional Conditions to Obligation of the Company. The obligation of the Company to effect the Merger is further subject to the satisfaction or (to the extent permitted by Law) waiver on or prior to the Closing of the following conditions:

(a) Representations and Warranties. (i) Each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02 (except for those contained in Section 3.02(c), Section 3.02(d)(i), Section 3.02(f)(i), Section 3.02(k) and Section 3.02(l)) shall be true and correct in all respects (disregarding all qualifications or limitations as to "materiality", "Parent Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date), except where the failure of such representations and warranties to be so true and correct has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect, (ii) each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02(c) shall be true and correct in all respects (except for de minimis inaccuracies) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date), (iii) each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02(d)(i) and Section 3.02(l) shall be true and correct in all material respects (disregarding all qualifications or limitations as to "materiality", "Parent Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date) and (iv) each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02(f)(i) and Section 3.02(k) shall be true and correct in all respects as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date);

(b) Performance of Obligations of Parent and Merger Sub. Each of Parent and Merger Sub shall have performed in all material respects all obligations required to be performed by it under this Agreement at or prior to the Closing Date; and

(c) Certificate. The Company shall have received a certificate of the Chief Executive Officer or the Chief Financial Officer of Parent, certifying that the conditions set forth in Section 6.03(a) and Section 6.03(b) have been satisfied.

SECTION 6.04. Frustration of Closing Conditions. None of the Company, Parent or Merger Sub may rely on the failure of any condition set forth in Section 6.01, Section 6.02 or Section 6.03, as the case may be, to be satisfied if such failure was primarily caused by such party's breach of this Agreement.

ARTICLE VII

TERMINATION

SECTION 7.01. Termination. This Agreement may be terminated and the Merger may be abandoned at any time prior to the Effective Time, whether before or after (except as set forth below) the Company Requisite Vote is obtained:

(a) by mutual written consent of Parent and the Company;

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(b) by either Parent or the Company:

(i) if the Merger shall not have been consummated on or before January 2, 2019 (the "Termination Date"); provided, however, that if any condition set forth in Section 6.01(b), Section 6.01(c) or Section 6.01(d) shall not have been satisfied at such time, the Termination Date shall automatically be extended to (and shall thereafter be deemed to be), without any action on the part of any party hereto, April 2, 2019; provided, further, that the right to terminate this Agreement pursuant to this Section 7.01(b)(i) shall not be available to any party if such party (or, in the case of Parent, Merger Sub) has breached its obligations under this Agreement in any manner that shall have been the principal cause of or resulted in the failure of a condition to any party's obligation to effect the Merger;

(ii) if at the Shareholders Meeting (or any adjournment or postponement thereof done in accordance with this Agreement), the Company Requisite Vote shall not have been obtained; or

(iii) if any Order permanently restraining, enjoining, preventing or otherwise prohibiting consummation of the Merger shall have become final and non-appealable; provided, however, that a party may not terminate this Agreement pursuant to this Section 7.01(b)(iii) if such party (or, in the case of Parent, Merger Sub) has breached its obligations under this Agreement in a manner that shall have been the principal cause of such Order;

(c) by the Company:

(i) if the Company Board has effected a Company Adverse Recommendation Change with respect to a Superior Proposal in accordance with Section 4.02(f) and shall have approved, and concurrently with the termination hereunder the Company shall have entered into, an Alternative Acquisition Agreement with respect to a Superior Proposal; provided, however, that such termination shall not be effective and the Company shall not enter into an Alternative Acquisition Agreement, unless (A) the Company shall have complied with the provisions of Section 4.02(f) and (B) the Company has paid the Company Termination Fee to Parent; provided, further, that the right to terminate this Agreement under this Section 7.01(c)(i) shall not be available after the Company Requisite Vote shall have been obtained; or

(ii) if Parent or Merger Sub shall have breached any of their respective representations or warranties or failed to perform any of their respective covenants or other agreements contained in this Agreement, where such breach or failure to perform (A) would give rise to the failure of a condition set forth in Section 6.03(a) or Section 6.03(b) and (B) cannot be cured by Parent or Merger Sub by the Termination Date, or if capable of being cured, is not cured prior to the earlier of (1) the thirtieth (30th) day after written notice thereof is given by the Company to Parent and (2) the third (3rd) Business Day immediately preceding the Termination Date; provided, however, that the Company shall not have the right to terminate this Agreement pursuant to this Section 7.01(c)(ii) if the Company is then in material breach of this Agreement;

(d) by Parent:

(i) if the Company Board (or a committee thereof) shall have effected a Company Adverse Recommendation Change; provided, however, that the right to terminate under this Section 7.01(d)(i) shall not be available after the Company Requisite Vote shall have been obtained; or

(ii) if the Company shall have breached any of its representations or warranties or failed to perform any of its covenants or other agreements contained in this Agreement, where such breach or failure to perform (A) would give rise to the failure of a condition set forth in Section 6.02(a) or Section 6.02(b) and (B) cannot be cured by Company by the Termination Date, or if capable of being cured, is not cured prior to the earlier of (1) the thirtieth (30th) day after written notice thereof is given by Parent to the Company and (2) the third (3rd) Business Day immediately preceding the Termination Date; provided, however, that Parent shall not have the right to terminate this Agreement pursuant to this Section 7.01(d)(ii) if either Parent or Merger Sub is then in material breach of this Agreement.

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SECTION 7.02. Effect of Termination and Abandonment.

(a) Except as provided in Section 7.02(b), in the event of termination of this Agreement and the abandonment of the Merger pursuant to this Article VII, this Agreement shall forthwith become void and of no effect and there shall be no liability or obligation on the part of any party hereto (or of any of its Representatives or Affiliates), except as provided in the last sentence of Section 5.02(c), Section 5.03(b), Section 5.07, Section 5.09(c), this Section 7.02 and Article VIII, which provisions shall survive such termination; provided, however, that subject to Section 7.02(b), Section 7.02(c), and Section 7.02(d), no such termination shall relieve any party hereto (treating Parent and Merger Sub as one party) of any liability for damages to any other party hereto resulting from any Willful Breach by the party (treating Parent and Merger Sub as one party) committing such Willful Breach prior to such termination, and the aggrieved party will be entitled to all rights and remedies available at law or in equity. The parties hereto acknowledge and agree that nothing in this Section 7.02 shall be deemed to affect their right to specific performance under Section 8.12.

(b) The Company shall pay or cause to be paid to Parent or its designee a non-refundable fee of $240,000,000 (the "Company Termination Fee") if:

(i) this Agreement is terminated by the Company pursuant to Section 7.01(c)(i);

(ii) (A) this Agreement is terminated (1) by Parent or the Company pursuant to Section 7.01(b)(i) or Section 7.01(b)(ii), or (2) by Parent pursuant to Section 7.01(d)(ii), (B) a bona fide Acquisition Proposal shall have been publicly announced or publicly disclosed and not have been withdrawn (1) in the case of a termination pursuant to Section 7.01(b)(i) or Section 7.01(d)(ii), prior to the date of such termination, and (2) in the case of a termination pursuant to Section 7.01(b)(ii), prior to the Shareholders Meeting, and (C) thereafter during the twelve (12) month period immediately following such termination, (1) the Company enters into an Alternative Acquisition Agreement or (2) an Acquisition Proposal is consummated; or

(iii) this Agreement is terminated by Parent pursuant to Section 7.01(d)(i);

If the Company Termination Fee becomes due pursuant to this Section 7.02(b), the Company shall pay Parent or its designee such Company Termination Fee by wire transfer of immediately available funds (x) in the case of a payment required by Section 7.02(b)(i), on the date of termination of this Agreement, (y) in the case of a payment required by Section 7.02(b)(ii), within two (2) Business Days after the earlier of the time when an Acquisition Proposal is consummated or an Alternative Acquisition Agreement is executed and (z) in the case of a payment required by Section 7.02(b)(iii), within two (2) Business Days of the date of termination of this Agreement, it being understood that in no event shall the Company be required to pay the Company Termination Fee on more than one occasion. Parent shall provide to the Company notice designating an account for purposes of payment of the Company Termination Fee within forty-eight (48) hours of a request by the Company to provide such information. For purposes of Section 7.02(b)(ii), the term "Acquisition Proposal" shall have the meaning assigned to such term in Exhibit A, except that all references to 15% therein shall be deemed to be references to 50%.

(c) Parent shall pay or cause to be paid to the Company or its designee a non-refundable fee of $280,000,000 (the "Parent Termination Fee") if:

(i) this Agreement is terminated by Parent or the Company pursuant to Section 7.01(b)(i) and, at the time of any such termination (A) the condition set forth in Section 6.02(d) shall not have been satisfied or waived with respect to one or more Regulatory Conditions and (B) the conditions set forth in Section 6.01(a), Section 6.01(b) – (d) (unless such condition was not satisfied solely due to the proposal of a Burdensome Condition to which Parent has not agreed), Section 6.01(f), Section 6.02(a), Section 6.02(b) and Section 6.02(e) shall have been satisfied or waived (except for any such conditions that have not been satisfied as a result of a breach by Parent or Merger Sub of any of their respective obligations under this Agreement);

(ii) this Agreement is terminated by Parent or the Company pursuant to Section 7.01(b)(iii) and, at the time of any such termination (A) the condition set forth in Section 6.02(d) shall not have been satisfied or

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waived with respect to one or more Regulatory Conditions and (B) the conditions set forth in Section 6.01(a), Section 6.01(b) – (d) (unless such condition was not satisfied solely due to the proposal of a Burdensome Condition to which Parent has not agreed), Section 6.01(f), Section 6.02(a), Section 6.02(b) and Section 6.02(e) shall have been satisfied or waived (except for any such conditions that have not been satisfied as a result of a breach by Parent or Merger Sub of any of their respective obligations under this Agreement); or

(iii) this Agreement is terminated by the Company pursuant to Section 7.01(c)(ii) due to a material breach by Parent or Merger Sub of its obligations under Section 5.02 which breach has caused the failure of a condition set forth in Section 6.01(b), Section 6.01(c), Section 6.01(d) , Section 6.02(d), Section 6.02(f), Section 6.02(g) or Section 6.02(h) to be satisfied.

If the Parent Termination Fee becomes due pursuant to this Section 7.02(c), Parent shall pay the Company or its designee the Parent Termination Fee by wire transfer of immediately available funds within two (2) Business Days of the date of termination of this Agreement, it being understood that in no event shall Parent be required to pay the Parent Termination Fee on more than one occasion. The Company shall provide to Parent notice designating an account for purposes of payment of the Parent Termination Fee within forty-eight (48) hours of a request by Parent to provide such information.

(d) Notwithstanding anything to the contrary in this Agreement, if this Agreement is terminated under circumstances in which the Company is required to pay the Company Termination Fee pursuant to Section 7.02(b) and the Company Termination Fee is paid, the payment of the Company Termination Fee shall be Parent's and Merger Sub's sole and exclusive remedy against the Company and its Affiliates, and their respective shareholders and Representatives, relating to or arising out of this Agreement, any agreement entered into in connection herewith or the transactions contemplated by this Agreement or thereby. Notwithstanding anything to the contrary in this Agreement, if this Agreement is terminated under circumstances in which Parent is required to pay the Parent Termination Fee pursuant to Section 7.02(c) and the Parent Termination Fee is paid, the payment of the Parent Termination Fee shall be the Company's sole and exclusive remedy against Parent, Merger Sub and their respective Affiliates, and their respective shareholders and Representatives, relating to or arising out of this Agreement, any agreement entered into in connection herewith or the transactions contemplated by this Agreement or thereby.

(e) Each party acknowledges that the agreements contained in Section 7.02(b) and Section 7.02(c) are an integral part of the transactions contemplated by this Agreement and that, without these agreements, such party would not enter into this Agreement. Accordingly, if the applicable party fails promptly to pay any amount due pursuant to Section 7.02(b) or Section 7.02(c), such party shall also pay any reasonable out-of-pocket costs, fees and expenses incurred by the other party (including reasonable legal fees and expenses) in connection with a Proceeding to enforce this Agreement that results in a final non-appealable Order for such amount against the party failing to promptly pay such amount. Any amount not paid when due pursuant to Section 7.02(b) or Section 7.02(c) shall bear interest from the date such amount is due until the date paid at a rate equal to the prime rate as published in *The Wall Street Journal, Eastern Edition*, in effect on the date of such payment.

ARTICLE VIII

MISCELLANEOUS

SECTION 8.01. Non-Survival. None of the representations, warranties, covenants and agreements in this Agreement or in any instrument delivered pursuant to this Agreement, including any rights arising out of any breach of such representations, warranties, covenants and agreements, shall survive the Effective Time, except for (a) those covenants and agreements contained herein that by their terms apply or are to be performed in whole or in part after the Effective Time and (b) those contained in this Article VIII.

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SECTION 8.02. Modification or Amendment. Subject to the requirements of applicable Law, at any time prior to the Effective Time, the parties hereto (in the case of the Company or Merger Sub, by action of their respective boards of directors to the extent required by Law) may modify or amend this Agreement by written agreement, executed and delivered by duly authorized officers of the respective parties. No modification or amendment will be made which, pursuant to applicable Law or the rules of the NYSE, requires further approval by the holders of Company Shares or the holders of the Parent Shares, as applicable, without such further approval being obtained.

SECTION 8.03. Waiver. Subject to the requirements of applicable Law, at any time prior to the Effective Time, any party hereto may (a) extend the time for the performance of any of the obligations or other acts of the other parties, (b) waive any inaccuracies in the representations and warranties of the other parties contained herein or in any document delivered pursuant hereto, or (c) waive compliance by the other parties with any of the agreements or conditions contained herein; provided, however, that neither Parent nor Merger Sub may perform any of the actions set forth in the foregoing clauses (a), (b) or (c) with respect to Merger Sub or Parent, respectively. No extension or waiver will be made which, pursuant to applicable Law or the rules of the NYSE, requires further approval by the holders of Company Shares or the holders of the Parent Shares, as applicable, without such further approval being obtained. Any such extension or waiver shall be valid only if set forth in an instrument in writing signed by the party or parties to be bound thereby and specifically referencing this Agreement. The failure of any party hereto to assert any rights or remedies shall not constitute a waiver of such rights or remedies.

SECTION 8.04. No Other Representations or Warranties.

(a) Except for the representations and warranties set forth in Section 3.01, each of Parent and Merger Sub acknowledges and agrees that (i) none of the Company, its Subsidiaries or any other Person makes any other express or implied representation or warranty in connection with the transactions contemplated by this Agreement, (ii) it has relied solely on the representations and warranties of the Company expressly set forth in Section 3.01 and (iii) it has not been induced to enter into this Agreement by any representation, warranty or statement of or by the Company, any of its Subsidiaries or any other Person.

(b) Except for the representations and warranties set forth in Section 3.02, the Company acknowledges and agrees that (i) none of Parent, Merger Sub, any of Parent's other Subsidiaries or any other Person makes any other express or implied representation or warranty in connection with the transactions contemplated by this Agreement, (ii) it has relied solely on the representations and warranties of Parent and Merger Sub expressly set forth Section 3.02 and (iii) it has not been induced to enter into this Agreement by any representation, warranty or statement of or by Parent, Merger Sub, any of the other Subsidiaries of Parent or any other Person.

SECTION 8.05. Notices. All notices, requests, claims, demands and other communications hereunder shall be in writing and shall be deemed given if delivered personally, faxed (with confirmation), electronically mailed in portable document format (PDF) (with confirmation) or sent by overnight courier (providing proof of delivery) to the parties at the following addresses (or at such other address for a party as shall be specified by like notice):

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if to Parent or Merger Sub, to:

Dominion Energy, Inc.
120 Tredegar Street
Richmond, Virginia 23219
Fax No.: (804) 819-2233
Attention: Mark O. Webb, Senior Vice President – Corporate Affairs and Chief Legal Officer
Carlos M. Brown, Vice President and General Counsel

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Email: mark.webb@dominionenergy.com
carlos.m.brown@dominionenergy.com

with a copy to (which shall not constitute notice):

McGuireWoods LLP
Gateway Plaza 800 East Canal Street
Richmond, Virginia 23219
Fax No.: (804) 698-2090
Attention: Joanne Katsantonis
John L. Hughes, Jr.
Email: jkatsantonis@mcguirewoods.com
jhughes@mcguirewoods.com

if to the Company, to:

SCANA Corporation
220 Operation Way, Mail Code D-308
Cayce, South Carolina 29033
Fax No.: (803) 933-7676
Attention: Jim Stuckey, Senior Vice President and General Counsel
Email: jim.stuckey@scana.com

with a copy to (which shall not constitute notice):

Mayer Brown LLP
71 South Wacker Drive
Chicago, Illinois 60606
Fax No.: (312) 706-8183
Attention: Frederick B. Thomas
William R. Kucera
Email: fthomas@mayerbrown.com
wkucera@mayerbrown.com

SECTION 8.06. Definitions. Capitalized terms used in this Agreement have the meanings specified in Exhibit A.

SECTION 8.07. Interpretation.

(a) When a reference is made in this Agreement to an Article, a Section, an Appendix or an Exhibit, such reference shall be to an Article or a Section of, or an Appendix or an Exhibit to, this Agreement unless otherwise indicated. The table of contents and headings contained in this Agreement are for reference purposes only and shall not affect in any way the meaning or interpretation of this Agreement.

(b) Whenever the words "include", "includes" or "including" are used in this Agreement, they shall be deemed to be followed by the words "without limitation". The words "hereof", "herein" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement. The word "or" when used in this Agreement is not exclusive.

(c) When a reference is made in this Agreement, the Company Disclosure Letter or the Parent Disclosure Letter to information or documents being "provided", "made available" or "disclosed" by a party hereto to another party or its Affiliates, such information or documents shall include any information or documents (i) included in the SEC Reports of such disclosing party which are publicly available at least twenty-four (24) hours prior to the date of this Agreement, (ii) furnished prior to the execution of this Agreement in the electronic "data room" maintained by such disclosing party and to which access has been granted to the other party and its Representatives at least twenty-four (24) hours prior to the date of this

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Agreement, or (iii) otherwise provided in writing (including electronically) to the other party or any of its Affiliates or Representatives at least twenty-four (24) hours prior to the date of this Agreement.

(d) The definitions contained in this Agreement are applicable to the singular as well as the plural forms of such terms and to the masculine as well as to the feminine and neuter genders of such term.

(e) Any agreement, instrument or statute defined or referred to herein means such agreement, instrument or statute as from time to time amended, modified or supplemented, including (in the case of agreements or instruments) by waiver or consent and (in the case of statutes) by succession of comparable successor statutes, and all attachments thereto and instruments incorporated therein.

(f) References to a Person are also to its permitted successors and permitted assigns.

(g) Where this Agreement states that a party "shall", "will" or "must" perform in some manner, it means that the party is legally obligated to do so under this Agreement.

(h) When calculating the period of time before which, within which or following which any act is to be done or step taken pursuant to this Agreement, (i) the date that is the reference date in calculating such period shall be excluded and (ii) if the last day of such period is not a Business Day, the period in question shall end on the next succeeding Business Day.

(i) Unless otherwise specifically indicated, any reference herein to $ means U.S. dollars.

(j) The parties hereto have participated jointly in the negotiation and drafting of this Agreement. If an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as jointly drafted by the parties hereto, and no presumption or burden of proof shall arise favoring or disfavoring any party by virtue of the authorship of any provision of this Agreement.

SECTION 8.08. Counterparts. This Agreement may be executed in one or more counterparts (including by facsimile or by attachment to electronic mail in portable document format (PDF)), and by the different parties hereto in separate counterparts, each of which when executed shall be deemed an original but all of which taken together shall be considered one and the same agreement and shall become effective when one or more counterparts have been signed by each of the parties hereto and delivered to the other parties hereto.

SECTION 8.09. Parties in Interest. This Agreement shall be binding upon and inure solely to the benefit of the parties hereto, and nothing in this Agreement, express or implied, is intended to or shall confer upon any other Person any rights, benefits or remedies of any nature whatsoever under or by reason of this Agreement, other than (a) after the Effective Time, with respect to the provisions of Section 5.08 which shall inure to the benefit of the Indemnified Parties who are intended to be third-party beneficiaries thereof, (b) after the Effective Time, the rights of the holders of Company Shares to receive the Merger Consideration in accordance with the terms and conditions of this Agreement, and (c) after the Effective Time, the rights of the holders of Company Performance Share Awards, Company RSUs and Company Deferred Units to receive the payments contemplated by the applicable provisions of Section 2.02, in each case, in accordance with the terms and conditions of this Agreement. The representations and warranties in this Agreement are the product of negotiations among the parties hereto and are for the sole benefit of such parties. Any inaccuracies in such representations and warranties are subject to waiver by the parties hereto in accordance with Section 8.03 without notice or liability to any other Person. In some instances, the representations and warranties in this Agreement may represent an allocation among the parties hereto of risks associated with particular matters regardless of the knowledge of any of the parties hereto. Consequently, Persons other than the parties hereto may not rely upon the representations and warranties in this Agreement as characterizations of actual facts or circumstances as of the date of this Agreement or as of any other date.

SECTION 8.10. Governing Law. This Agreement shall be governed by, and construed in accordance with, the internal Laws and judicial decisions of the State of Delaware applicable to agreements executed and performed entirely within such State, regardless of the Law that might otherwise govern under applicable

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principles of conflicts of law thereof, except that matters related to the obligations of the Company Board under the SCBCA and matters that are specifically required by the SCBCA in connection with the transactions contemplated by this Agreement shall be governed by the laws of the State of South Carolina.

SECTION 8.11. Entire Agreement; Assignment. This Agreement (including the Appendices and Exhibits hereto, the Company Disclosure Letter and the Parent Disclosure Letter) and the Confidentiality Agreement constitute the entire agreement among the parties hereto with respect to the subject matter hereof and supersede all prior and contemporaneous agreements and undertakings, both written and oral, among the parties, or any of them, with respect to the subject matter hereof. Neither this Agreement nor any of the rights, interests or obligations hereunder may be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of the other parties hereto. Any purported assignment in contravention of this Agreement is and shall be null and void. Subject to the immediately preceding two sentences, this Agreement will be binding upon, inure to the benefit of and be enforceable by the parties hereto and their respective successors and permitted assigns.

SECTION 8.12. Specific Enforcement; Consent to Jurisdiction.

(a) The parties hereto agree that irreparable damage for which monetary damages, even if available, would not be an adequate remedy, would occur in the event that any of the parties hereto do not perform the provisions of this Agreement (including failing to take such actions as are required of it hereunder in order to consummate the transactions contemplated by this Agreement) in accordance with its specified terms or otherwise breach such provisions. The parties hereto acknowledge and agree that each party hereto shall be entitled to seek an injunction, specific performance and other equitable relief to prevent breaches of this Agreement and to seek to enforce specifically the terms and provisions hereof, this being in addition to any other remedy to which it is entitled at law or in equity. Each of the parties hereto further agrees that it will not oppose the granting of an injunction, specific performance and other equitable relief as provided herein on the basis that (A) the other party has an adequate remedy at law or (B) an award of specific performance is not an appropriate remedy for any reason at law or equity. Any party hereto seeking an Order to prevent breaches of this Agreement and to enforce specifically the terms and provisions of this Agreement shall not be required to provide any bond or other security in connection with any such Order.

(b) Each of the parties hereto irrevocably (i) submits itself to the personal jurisdiction of the federal courts located in the State of Delaware and any appellate court therefrom, in connection with any claim or matter directly or indirectly based upon, arising out of or relating to this Agreement or any of the transactions contemplated by this Agreement or the actions of Parent, Merger Sub or the Company in the negotiation, administration, performance and enforcement of this Agreement, (ii) agrees that it will not attempt to deny or defeat such personal jurisdiction by motion or other request for leave from any such court, (iii) agrees that it will not bring any action relating to this Agreement or any of the transactions contemplated by this Agreement in any court other than the federal courts located in the State of Delaware and (iv) agrees that the service of any process, summons, notice or document through the notice procedures set forth in Section 8.05 or by U.S. registered mail to the respective addresses set forth in Section 8.05 shall be effective service of process for any Proceeding in connection with this Agreement or the transactions contemplated by this Agreement. Each party hereto hereby irrevocably waives, and agrees not to assert, by way of motion, as a defense, counterclaim or otherwise, in any Proceeding with respect to this Agreement, any claim that (A) it is not personally subject to the jurisdiction of the above-named courts for any reason other than the failure to serve process in accordance with this Section 8.12(b), (B) it or its property is exempt or immune from jurisdiction of any such court or from any legal process commenced in such courts (whether through service of notice, attachment prior to judgment, attachment in aid of execution of judgment, execution of judgment or otherwise), (C) the Proceeding in any such court is brought in an inconvenient forum, (D) the venue of such Proceeding is improper, or (E) this Agreement, or the subject matter hereof, may not be enforced in or by such courts. Furthermore, each of the Company, Parent and Merger Sub irrevocably waives, to the fullest extent permitted by applicable Law, the benefit of any defense that would hinder, fetter or delay the levy, execution or collection of any amount to which any party is

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entitled pursuant to the final judgment of any court having jurisdiction. Each party hereto expressly acknowledges that the foregoing waiver is intended to be irrevocable under the Law of the State of Delaware and of the United States of America; provided, however, that each such party's consent to jurisdiction and service contained in this Section 8.12 is solely for the purpose referred to in this Section 8.12 and shall not be deemed to be a general submission to said courts or to courts in the State of Delaware other than for such purpose.

SECTION 8.13. WAIVER OF JURY TRIAL. EACH PARTY HERETO ACKNOWLEDGES AND AGREES THAT ANY CONTROVERSY WHICH MAY ARISE UNDER THIS AGREEMENT IS LIKELY TO INVOLVE COMPLICATED AND DIFFICULT ISSUES, AND THEREFORE IT HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVES TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW ANY AND ALL RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY PROCEEDING (WHETHER BASED ON CONTRACT, TORT OR OTHERWISE) DIRECTLY OR INDIRECTLY BASED UPON, ARISING OUT OF OR RELATING TO THIS AGREEMENT OR ANY OF THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT OR THE ACTIONS OF PARENT, MERGER SUB OR THE COMPANY IN THE NEGOTIATION, ADMINISTRATION, PERFORMANCE AND ENFORCEMENT OF THIS AGREEMENT. EACH PARTY CERTIFIES AND ACKNOWLEDGES THAT (A) NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER, (B) IT UNDERSTANDS AND HAS CONSIDERED THE IMPLICATIONS OF SUCH WAIVER, (C) IT MAKES SUCH WAIVER VOLUNTARILY AND (D) IT HAS BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVER AND CERTIFICATIONS IN THIS SECTION 8.13.

SECTION 8.14. Severability. If any term or other provision of this Agreement is found by a court of competent jurisdiction to be invalid, illegal or incapable of being enforced by any rule of Law or public policy, all other terms and provisions of this Agreement shall nevertheless remain in full force and effect. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the parties hereto shall negotiate in good faith to modify this Agreement so as to effect the original intent of the parties hereto as closely as possible in an acceptable manner to the end that the transactions contemplated by this Agreement are fulfilled to the fullest extent possible.

SECTION 8.15. Transfer Taxes. All transfer, documentary, sales, use, stamp, registration and other Taxes and fees (including penalties and interest) incurred in connection with the Merger shall be paid by Parent and Merger Sub when due.

SECTION 8.16. Disclosure Letters. Certain items and matters are listed in the Company Disclosure Letter and the Parent Disclosure Letter for informational purposes only and may not be required to be listed therein by the terms of this Agreement. In no event shall the listing of items or matters in the Company Disclosure Letter or the Parent Disclosure Letter be deemed or interpreted to broaden, or otherwise expand the scope of, the representations and warranties or covenants and agreements contained in this Agreement. No reference to, or disclosure of, any item or matter in any Section of this Agreement or any section or subsection of the Company Disclosure Letter or the Parent Disclosure Letter shall be construed as an admission or indication that such item or matter is material or that such item or matter is required to be referred to or disclosed in this Agreement or in the Company Disclosure Letter or the Parent Disclosure Letter, as applicable. Without limiting the foregoing, no reference to, or disclosure of, a possible breach or violation of any Contract or Law in the Company Disclosure Letter or the Parent Disclosure Letter shall be construed as an admission or indication that a breach or violation exists or has actually occurred. Each section or subsection of the Company Disclosure Letter and the Parent Disclosure Letter, as the case may be, shall be deemed to qualify the corresponding section or subsection of this Agreement, irrespective of whether or not any particular section or subsection of this Agreement specifically refers to the Company Disclosure Letter or the Parent Disclosure Letter, as the case may be.

[*Signature Pages Follow*]

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IN WITNESS WHEREOF, the Company, Parent and Merger Sub have caused this Agreement to be signed by their respective officers thereunto duly authorized, all as of the date first written above.

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SCANA CORPORATION

By: /s/ Jimmy E. Addison
Name: Jimmy E. Addison
Title: Chief Executive Officer

[Signature page to Agreement and Plan of Merger]

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DOMINION ENERGY, INC.

By: /s/ Thomas F. Farrell, II
Name: Thomas F. Farrell, II
Title: President and Chief Executive Officer

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SEDONA CORP.

By: /s/ Mark F. McGettrick
Name: Mark F. McGettrick
Title: President

[Signature page to Agreement and Plan of Merger]

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APPENDIX A

SCPSC PETITION

1. To meet commitments made by South Carolina Electric & Gas Company to the SCPSC, South Carolina Electric & Gas Company and Parent will jointly file the Petition on or before January 12, 2018.

2. The Petition will seek a ruling from the SCPSC (i) approving the Merger with no material changes to the terms of the Merger; (ii) making a finding that the Merger is in the public interest; or (iii) making a finding that there is an absence of harm to South Carolina rate payers as a result of the Merger.

3. The Petition will acknowledge that the Merger can only close if the SCPSC approves the jointly proposed NND Project cost recovery plan, with (x) no material change to the terms, conditions or undertakings set forth in the plan and (y) no significant change to the economic value of the plan, in each case as reasonably determined by Parent in good faith (except in each case unless otherwise consented to by Parent in its sole discretion), which shall include the following terms:

   a. There will be an aggregate up-front, one-time rate credit totaling $1.3 billion[1] to all current South Carolina Electric & Gas Company electric customers as of the date of Merger close. The rate credit will be apportioned to all retail electric customer classes based on their 2016 contribution to summer adjusted peak demand as prepared by South Carolina Electric & Gas Company. After the dollar apportionment per customer class and rate schedule is determined on this basis, a rate per kilowatt hour ($/kWh) will be derived by customer class and rate schedule by dividing the total kWh sales of electricity by customer class and rate schedule over a preceding 12-month period (the "Base Period") into the apportioned funding amount. The $/kWh rate will then be applied to each customer's kWh usage over the Base Period to determine the customer's up-front rate credit amount. The rate credit will be issued to eligible customers in the form of a check issued within 90 days of Merger close. Eligible customers shall be South Carolina Electric & Gas Company retail electric customers as of record on the date of the close of the Merger.

   b. South Carolina Electric & Gas Company will immediately upon Merger closing write down its investment in construction work in progress associated with the new nuclear development project by approximately $1.4 billion, which amount includes approximately $1.2 billion in assets that have not previously been subject to consideration in setting revised rates and approximately $200 million that have been so considered. The amounts written down would be permanently excluded from consideration in establishing retail electric rates going forward.

   c. South Carolina Electric & Gas Company will not seek recovery of the approximately $320 million in regulatory assets associated with the following items:

      i. The approximately $173 million regulatory asset associated with interest rate swap losses related to the debt that was not issued for the NND Project;

      ii. The approximately $66 million regulatory asset associated with the NND Project Equity AFUDC;

      iii. The approximately $52 million regulatory asset associated with the carrying costs on deferred tax assets related to nuclear construction; and

      iv. The regulatory asset associated with foregone domestic production activities deductions will be written off and not be recovered from customers. The net regulatory asset associated with research and experimentation credit claims, interest, and legal costs expected to be incurred in defending these claims, will be borne by the shareholders and not returned to or collected from customers.

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1 The net proceeds of the Toshiba settlement were utilized by South Carolina Gas & Electric Company to repay indebtedness in 2017, and therefore those funds are unavailable for refund. A portion of the one time rate credit will be funded through issuance of debt and defeasement of the regulatory liability associated with the Toshiba settlement.

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d. Parent will underwrite an approximately $575 million refund for amounts previously collected under the NND Project (regulatory liability) which is estimated to provide the 3.5% retail electric rate decrease from the 2017 rate level until accumulated amortization of the cost of abandoned plant lowers South Carolina Electric & Gas Company's revenue requirements. The refund amount is calculated to be sufficient to support the 3.5% retail electric rate reduction for approximately eight (8) years following the closing of the Merger. This amount of time is estimated to be sufficient to avoid a future retail electric rate increase resulting from new nuclear project costs when the refund amount is exhausted.

e. Parent will reduce retail electric rates further to reflect the impact of federal tax reform passed in December of 2017 which is estimated to lower rates an additional amount resulting in a total estimated rate reduction of approximately 5%.

f. An SCPSC finding, as necessary, that South Carolina Electric & Gas Company's investment in construction work in progress for new nuclear project in the amount of approximately $3.3 billion, which reflects the amount of that investment net of write-downs and offsets, was prudent; and that the capital costs and amortization of that $3.3 billion may be recovered through retail electric rates.

g. An SCPSC order directing that:

   i. The approximately $3.3 billion of invested capital for the new nuclear development project shall be included in a regulatory asset and recovered through rates over a 20-year amortization and recovery period that is reflected in retail electric revenue requirements without offset or disallowance until the regulatory asset is fully recovered; and

   ii. Until the balance in the regulatory asset is fully recovered, the capital costs associated with the unrecovered balance in that account shall be reflected in South Carolina Electric & Gas Company's cost of capital devoted to retail electric operations at a rate that reflects a return on common equity of 10.25%,[2] a weighted average cost of debt of 5.85%, and a capital structure consisting of 52.81% equity and 47.19% debt, with these percentages fixed over the 20-year amortization period.

h. The deferred tax liability associated with the tax abandonment of the NND Project shall reduce the NND Project cost to be recovered from South Carolina Electric & Gas Company customers. The deferred tax asset for the net operating loss carryforward resulting from the tax abandonment of the NND Project shall be reflected as a rate base offset, dollar for dollar, to the deferred tax liability. Reductions in the deferred tax asset shall be subject to Parent's ability to use the net operating loss in filing its consolidated income tax returns and shall not be computed on a separate company basis.

i. Adjustments to the deferred tax liability and the deferred tax asset described in item (h) of this subsection resulting from a change in tax laws or tax treatment of the abandonment and/or Parent's ability to use the net operating loss will be returned to or recovered from South Carolina Electric & Gas Company customers in the following manner:

   i. The regulatory liability resulting from excess deferred tax liabilities on the tax abandonment will be returned to customers over the book recovery period of the property (*i.e*., 20 years);

   ii. The regulatory asset resulting from excess deferred tax assets on the net operating loss will be recovered from customers in a manner that coincides with Parent's ability to use the net operating loss in filing its consolidated income tax returns and not on a separate company basis; and

   iii. As adjusted for any impacts related to the tax treatment of the abandonment loss

j. The approximately $180 million initial capital investment in the Columbia Energy Center, a 540-megawatt combined-cycle, natural gas-fired power plant located in Gaston, S.C., will be excluded

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2 The current allowed blended ROE for NND is approximately 10.9% but the proposal is to adjust the rate down to South Carolina Gas & Electric Company's base ROE of 10.25%.

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from rate base and rate recovery, with only the ongoing costs such as fuel costs, operations and maintenance expense, and maintenance or improvement capital investments associated with the plant to be recovered in future base and fuel rates.

k. Transmission projects associated with the new nuclear project will be closed to rate base and removed from BLRA project costs. The revenue of approximately $32 million per year currently being recovered in base rates will continue to be recovered through base rates notwithstanding the Merger. The associated depreciation and operating and maintenance costs will be captured in a regulatory asset for future rate recovery.

l. Except for rate adjustments for fuel and environmental costs, demand side management costs and other rates routinely adjusted on an annual or biannual basis, retail electric base rates will remain frozen at current levels until January 1, 2021.

4. The parties shall request approval of the SCPSC Petition, including the NND Project cost recovery plan, within 6 months from the date of filing.

5. South Carolina Electric & Gas Company and Parent commit to support and advocate for SCPSC approval or adoption of the terms, both individually and collectively, and without modification, identified and described in Paragraphs (2) and (3) above (the “Merger Terms”) and will take no action inconsistent with this commitment. In the Petition to be jointly filed on January 12, 2018, South Carolina Electric & Gas Company may also present alternative terms for NND Project cost recovery, consistent with and based on the terms publically disclosed by Mr. Kissam on November 16, 2017 and previously provided to Parent in a more comprehensive form in a proposed draft of the Petition (the “Alternative Terms”). South Carolina Electric & Gas Company may provide any necessary testimony, exhibits or supporting materials in order to meet prior commitments to the SCPSC concerning the substance of South Carolina Electric & Gas Company’s January 12, 2018 filing or to show that the Alternative Terms, as a disfavored alternative to the Merger Terms, are nonetheless just, reasonable, lawful, fair and non-confiscatory and should be adopted by the SCPSC if the Merger is not approved. However, South Carolina Electric & Gas Company will not support or advocate for the Alternative Terms except as an expressly disfavored alternative to the Merger Terms and in each case where it discusses the Alternative Terms in testimony, exhibits or otherwise, will expressly state South Carolina Electric & Gas Company’s overriding commitment to the Merger Terms as being in the best interest of customers and the State of South Carolina, and that the Alternative Terms are a disfavored alternative to be considered only if the Merger is disapproved. South Carolina Electric & Gas Company will not otherwise advocate for any other terms for NND cost recovery differing from those identified in Paragraphs (2) and (3) above (without prior consent of Parent), unless and until the Merger Agreement is terminated.

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EXHIBIT A

DEFINITIONS

(a) The following terms have the following meanings:

"Acceptable Confidentiality Agreement" means a confidentiality agreement having provisions as to confidential treatment of the Company's information that are not materially less favorable to those contained in the Confidentiality Agreement.

"Acquisition Proposal" means any bona fide proposal or offer from any Person or group of Persons (other than Parent, Merger Sub or their respective Affiliates) relating to (i) any acquisition or purchase directly or indirectly, in a single transaction or series of transactions, of a business that constitutes more than 15% of the net revenues, net income or consolidated assets of the Company and its Subsidiaries, taken as a whole, or more than 15% of the total voting power of the equity securities of the Company, (ii) any tender offer or exchange offer that if consummated would result in any Person beneficially owning more than 15% of the total voting power of the equity securities of the Company or (iii) any merger, reorganization, consolidation, share exchange, business combination, recapitalization, liquidation, joint venture, partnership, dissolution or similar transaction involving directly or indirectly, in a single transaction or series of transactions, the Company (or any Subsidiary or Subsidiaries of the Company whose business constitutes more than 15% of the net revenues, net income or consolidated assets of the Company and its Subsidiaries, taken as a whole).

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such first Person.

"Atomic Energy Act" means the Atomic Energy Act of 1954, as amended.

"Average Price" means the volume-weighted average price, rounded to four decimal places, of Parent Shares for the ten (10) consecutive trading days ending on and including the second (2^{nd}) trading day prior to the Effective Time.

"BLRA" means the South Carolina Base Load Review Act of 2007 as amended, S.C. Code Ann. § 58-33-210 *et seq*.

"Burdensome Condition" shall mean any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions (including any Remedial Action) that, in the aggregate, would have or would reasonably be expected to have, a material adverse effect on the business, financial condition, assets, liabilities or results of operations of the Company and its Subsidiaries, taken as a whole, or of Parent and its Subsidiaries, taken as a whole; provided, however, that, for this purpose, Parent and its Subsidiaries, and after giving effect to the Merger, Parent and its Subsidiaries, shall be deemed to be a consolidated group of entities of the size and scale of a hypothetical company that is 100% of the size and scale of the Company and its Subsidiaries, taken as a whole as of immediately prior to the Effective Time; and provided, further, that any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions relating to implementing, or otherwise arising or resulting from or imposed by, the Social Commitments, or any relief or other matters contemplated by the SCPSC Petition or the SCPSC Petition Approval, shall not constitute or be taken into account in determining whether there has been or is such a material adverse effect.

"Business Day" means any day other than a Saturday or Sunday or a day on which banks in the City of New York are required or authorized to be closed.

"Byproduct Material" means any radioactive material (except Special Nuclear Material) yielded in, or made radioactive by, exposure to radiation in the process of producing or utilizing Special Nuclear Material.
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“Code” means the Internal Revenue Code of 1986, as amended.

“Commonly Controlled Entity” means, with respect to the Company, any other Person that, together with the Company, is treated as a single employer under Section 414 of the Code.

“Company Benefit Plan” means any (i) “employee benefit plan” (within the meaning of Section 3(3) of ERISA), (ii) bonus, incentive or deferred compensation or equity or equity-based compensation plan, program, policy or arrangement (including the Company Equity Award Plans), (iii) severance, change in control, employment, consulting, retirement, retention or termination plan, program, agreement, policy or arrangement or (iv) other compensation or benefit plan, program, agreement, policy, practice, Contract, arrangement or other obligation, whether or not in writing and whether or not subject to ERISA, in each case, sponsored, maintained, contributed to or required to be maintained or contributed to by the Company or any Commonly Controlled Entity or with respect to which the Company or any Commonly Controlled Entity had or has any present or future liability, in any case other than any (A) “multiemployer plan” (within the meaning of Section 3(37) of ERISA) or (B) plan, program, policy or arrangement mandated by applicable Law.

“Company Disclosure Letter” means the confidential disclosure letter dated as of the date of this Agreement delivered by the Company to Parent and Merger Sub.

“Company Equity Award Plans” means the 2015 Long-Term Equity Compensation Plan, the 2000 Long-Term Equity Compensation Plan, and the Director Compensation and Deferral Plan, each as amended and restated from time to time.

“Company Material Adverse Effect” means any Change that has a material adverse effect on the business, financial condition, assets, liabilities or results of operations of the Company and its Subsidiaries, taken as a whole; provided, however, that none of the following shall, either alone or in combination, constitute or contribute to a Company Material Adverse Effect: (i) Changes in the economy in the United States or elsewhere in the world, including as a result of changes in geopolitical conditions, (ii) Changes that affect any of the industries in which the Company or any of its Subsidiaries operate, (iii) Changes in the financial, debt, capital, credit or securities markets generally in the United States or elsewhere in the world, including changes in interest rates, (iv) any Change in the stock price, trading volume or credit rating of the Company or any of its Subsidiaries or any failure by the Company to meet published analyst estimates or expectations of its revenue, earnings or other financial performance or results of operations for any period, or any failure by the Company to meet its internal or published projections, budgets, plans or forecasts of its revenues, earnings or other financial performance or results of operations for any period (it being understood that the Changes underlying any such Change or failure described in this clause (iv) to the extent not otherwise excluded from the definition of a “Company Material Adverse Effect” may be considered in determining whether there has been a Company Material Adverse Effect), (v) Changes in Law, legislative or political conditions or policy or practices of any Governmental Entity (other than SC Law Changes), (vi) Changes in applicable accounting regulations or principles or interpretations thereof, (vii) an act of terrorism or an outbreak or escalation of hostilities or war (whether declared or not declared) or earthquakes, any weather-related or other force majeure events or other natural disasters or any national or international calamity or crisis, (viii) the announcement, execution or delivery of this Agreement or the public announcement or pendency of the Merger or the other transactions contemplated by this Agreement, in each case, including any impact thereof on relationships, contractual or otherwise, with Governmental Entities or customers, suppliers, distributors, lenders, partners or employees of the Company and its Subsidiaries, (ix) actions taken or requirements imposed by any Governmental Entities, in connection with obtaining the Regulatory Clearances or the SCPSC Petition Approval, (x) any Shareholder Litigation or Changes with respect thereto and (xi) any Proceedings, claims, investigations or inquiries set forth in Section 3.01(g) of the Company Disclosure Letter (other than with respect to SC Law Changes) or any Changes with respect thereto, provided, further, that any Change set forth in the foregoing clauses (i), (ii), (iii), (v) or (vi), to the extent not otherwise excluded hereunder, may be taken into account in determining whether a Company Material Adverse Effect has occurred solely to the extent that such Change has a materially disproportionate adverse

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effect on the Company and its Subsidiaries, taken as a whole, as compared to other Persons engaged in the relevant business affected by such Change.

"Company Material Contract" means any Contract (i) required to be filed by the Company as a "material contract" pursuant to Item 601(b)(10) of Regulation S-K under the Securities Act, (ii) that provides for Indebtedness of the Company or any of its Subsidiaries of more than $50,000,000, (iii) that resulted in expenditures, receipts, liabilities, or payments by the Company or any of its Subsidiaries of more than $80,000,000 in the 2016 fiscal year or 2017 fiscal year or (iv) that requires the Company or any of its Subsidiaries to incur Indebtedness or liabilities, or to make payments or expenditures, of more than $80,000,000 in any one future fiscal year, in the case of the foregoing clauses (ii) and (iii), excluding (A) any Contracts that can be terminated for convenience on less than ninety (90) days' notice without material payment or penalty and (B) any Contracts for the supply of natural gas capacity or commodity.

"Company Share" means a share of common stock, without par value, of the Company.

"Consent" means any consent, clearance, approval, Order, authorization, waiver, license, notice filing, action or non-action.

"Contract" means a contract, purchase order, license, sublicense, lease, sublease, option, warrant, guaranty, indenture, note, bond, mortgage or other legally binding agreement or instrument, whether written or unwritten.

"control" (including in the terms "controlling", "controlled", "controlled by" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of a Person, whether through the ownership of voting securities, by Contract or otherwise.

"Data Privacy Legal Requirements" mean (i) all applicable requirements imposed by applicable Laws relating to (A) the security or privacy of information systems, networks, or data; (B) the use, collection, recording, storing, altering, retrieving, transferring, disclosing (whether authorized or unauthorized) or otherwise processing of data owned or used by the Company or its Subsidiaries; (C) the unauthorized access, acquisition, use, modification, disclosure or misuse of data; (D) the notification to affected parties, regulators, or credit reporting agencies as a result of any breach of systems, networks or data; or (E) any other cybersecurity or data privacy incident requiring reporting outside of the Company; (ii) all contractual standards, rules and requirements that the Company or any of its Subsidiaries is or has been contractually obligated to comply with; and (iii) each published external or internal, past or present Company privacy policy or security policy applicable to any information systems, networks, or data, including personal data and any published policy of the Company or its Subsidiaries relating to: (A) the privacy of any Person, (B) financial records or information pertaining to any Person, (C) the collection, storage, disclosure, transfer, disposal, other processing or security of any personal data, or (D) personally identifying information, sensitive customer information, financial records, security records and associated information, about Persons.

"Director Compensation and Deferral Plan" means the Company Director Compensation and Deferral Plan.

"Environmental Law" means any Law relating to pollution or protection of the environment or natural resources, including ambient air, soil, surface water or groundwater, sediment, flora and fauna, or, as it relates to the exposure to hazardous, deleterious or toxic materials, human health or safety.

"Equity Award Consideration" means an amount in cash, without interest, equal to the product of (i) the Merger Consideration multiplied by (ii) the Average Price.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

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"Executive Deferred Compensation Plan" means the Company Executive Deferred Compensation Plan.

"Governmental Entity" means any federal, state, local, or non-United States government, any court or tribunal of competent jurisdiction, any administrative, regulatory (including any stock exchange) or other governmental or quasi-governmental agency, commission, branch or authority or other governmental entity or body (it being understood and agreed that no reference to "Governmental Entity" in this Agreement shall be deemed to include Santee Cooper in its capacity as a commercial counterparty of the Company in connection with the NND Project or otherwise).

"Hazardous Materials" means any substance, waste or material defined or regulated as hazardous, acutely hazardous or toxic or that could reasonably be expected to result in liability under any applicable Environmental Law currently in effect, including petroleum, petroleum products, High-Level Waste, Spent Nuclear Fuel, by-products and distillates, pesticides, dioxin, polychlorinated biphenyls, mold, biological hazards, asbestos and asbestos-containing materials.

"High-Level Waste" means (i) irradiated nuclear reactor fuel, (ii) liquid wastes resulting from the operation of the first cycle solvent extraction system, or its equivalent, and the concentrated wastes from subsequent extraction cycles, or their equivalent, in a facility for reprocessing irradiated reactor fuel and (iii) solids into which such liquid wastes have been converted.

"HSR Act" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

"Intellectual Property" means all intellectual property and proprietary rights, and applications with respect thereto, including (i) patents and patent applications, (ii) trademarks, service marks, trade dress, logos, Internet domain names, trade names and corporate names, whether registered or unregistered, and the goodwill associated therewith, together with any registrations and applications for registration thereof, (iii) copyrights and rights under copyrights, whether registered or unregistered, and any registrations and applications for registration thereof, (iv) trade secrets and other rights in know-how and confidential or proprietary information, including any technical data, specifications, techniques, inventions and discoveries, in each case, to the extent that it qualifies as a trade secret under applicable Law and (v) all other intellectual property rights recognized by applicable Law.

"Intervening Event" means any material event, development or change in circumstances that materially affects the business, assets or operations of the Company and its Subsidiaries, taken as a whole, that first becomes known to the Company Board or any of the Persons set forth in Section 8.06 of the Company Disclosure Letter or their successors after the date of this Agreement but before the Company Requisite Vote is obtained, to the extent that such event, development or change in circumstances was not reasonably foreseeable as of or prior to the date of this Agreement or which would not reasonably be expected to have become known after reasonable investigation or inquiry as of or prior to the date of this Agreement; provided, however, that in no event will (i) the receipt, existence or terms of an Acquisition Proposal or any matter relating thereto or consequence thereof, (ii) any action taken by the parties pursuant to or in compliance with this Agreement, including any action taken in connection with seeking any Regulatory Clearances, (iii) any changes in Law or the settlement of any lawsuits, investigations, inquiries or Proceedings, (iv) changes in the market price or trading volume of the Company Shares or Parent Shares, or the Company or Parent or any their respective Subsidiaries meeting or exceeding internal or published projections, forecasts or revenue or earnings predictions for any period, (v) changes in the energy markets or industry or to rates, or (vi) any event, development or change relating solely to Parent or its Affiliates, in each case, constitute an "Intervening Event" or be taken into account in determining whether an Intervening Event has occurred or would reasonably be expected to result.

"IT Systems" means all computer systems, computer programs, networks, hardware, software, software engines, electronic databases and websites used to process, store, maintain and operate data, information and control systems owned, used or provided by the Company.
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"Knowledge" means (i) with respect to the Company, the actual knowledge, after reasonable inquiry, of any of the Persons set forth in Section 8.06 of the Company Disclosure Letter and their successors and (ii) with respect to Parent or Merger Sub, the actual knowledge, after reasonable inquiry, of any of the Persons set forth in Section 8.06 of the Parent Disclosure Letter and their successors.

"Law" means any federal, state, local or non-United States law, statute, regulation, rule, ordinance, Order or decree of any Governmental Entity.

"Low-Level Waste" means radioactive material that (i) is not High-Level Waste, Mixed Waste, Spent Nuclear Fuel or Byproduct Material as defined in section 11e.(2) of the Atomic Energy Act, and (ii) the NRC classifies as low-level radioactive waste.

"Mixed Waste" means waste that (i) contains both a hazardous waste component regulated under the Resource Conservation and Recovery Act (42 U.S.C. § 6901 *et seq*.) and a radioactive component of Source Material, Byproduct Material or Special Nuclear Material and (ii) the NRC classifies as mixed waste or that constitutes "mixed waste" as defined in 42 U.S.C. § 6903(41).

"NND Project" means the New Nuclear Development Project under which the Company and Santee Cooper undertook to construct two Westinghouse AP1000 Advanced Passive Safety nuclear units in Jenkinsville, South Carolina.

"Nuclear Material" means Source Material, Special Nuclear Material, Low-Level Waste, High-Level Waste, the radioactive component of Mixed Waste, Byproduct Material and Spent Nuclear Fuel.

"NYSE" means the New York Stock Exchange.

"Parent Disclosure Letter" means the confidential disclosure letter dated as of the date of this Agreement delivered by Parent to the Company.

"Parent Material Adverse Effect" means any Change that has a material adverse effect on the business, financial condition, assets, liabilities or results of operations of Parent and its Subsidiaries, taken as a whole; provided, however, that none of the following shall, either alone or in combination, constitute or contribute to a Parent Material Adverse Effect: (i) Changes in the economy in the United States or elsewhere in the world, including as a result of changes in geopolitical conditions, (ii) Changes that affect any of the industries in which Parent or any of its Subsidiaries operate, (iii) Changes in the financial, debt, capital, credit or securities markets generally in the United States or elsewhere in the world, including changes in interest rates, (iv) any Change in the stock price, trading volume or credit rating of Parent or any of its Subsidiaries or any failure by Parent to meet published analyst estimates or expectations of its revenue, earnings or other financial performance or results of operations for any period, or any failure by Parent to meet its internal or published projections, budgets, plans or forecasts of its revenues, earnings or other financial performance or results of operations for any period (it being understood that the Changes underlying any such Change or failure described in this clause (iv) to the extent not otherwise excluded from the definition of a "Parent Material Adverse Effect" may be considered in determining whether there has been a Parent Material Adverse Effect), (v) Changes in Law, legislative or political conditions or policy or practices of any Governmental Entity (other than SC Law Changes), (vi) Changes in applicable accounting regulations or principles or interpretations thereof, (vii) an act of terrorism or an outbreak or escalation of hostilities or war (whether declared or not declared) or earthquakes, any weather-related or other force majeure events or other natural disasters or any national or international calamity or crisis, (viii) the announcement, execution or delivery of this Agreement or the public announcement or pendency of the Merger or the other transactions contemplated by this Agreement, in each case, including any impact thereof on relationships, contractual or otherwise, with Governmental Entities or customers, suppliers, distributors, lenders, partners or employees of Parent and its Subsidiaries, (ix) actions taken or requirements imposed by any Governmental Entities, in connection with obtaining the Regulatory Clearances or the SCPSC Petition Approval,
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(x) any Shareholder Litigation or any Changes with respect thereto, and (xi) any Proceedings, claims, investigations or inquiries set forth in Section 3.02(g) of the Parent Disclosure Letter or any Changes with respect thereto, provided, further, that any Change set forth in the foregoing clauses (i), (ii), (iii), (v) or (vi), to the extent not otherwise excluded hereunder, may be taken into account in determining whether a Parent Material Adverse Effect has occurred solely to the extent that such Change has a materially disproportionate adverse effect on the Parent and its Subsidiaries, taken as a whole, as compared to other Persons engaged in the relevant business affected by such Change.

"Parent Severance Program" means the severance program sponsored by Parent and described in the summary plan description attached as Section 5.06 of the Parent Disclosure Letter.

"Parent Share" means a share of common stock, without par value, of Parent.

"Parent Significant Subsidiaries" means the significant subsidiaries (as defined in Rule 1-02(w) of Regulation S-X) of Parent, excluding, if otherwise included, Dominion Energy Midstream Partners LP.

"Permitted Liens" means, with respect to any Person, (i) mechanics', materialmen's, carriers', workmen's, repairmen's, vendors', operators' or other like Liens, if any, that do not materially detract from the value of or materially interfere with the use of any of the assets of such Person and its Subsidiaries as currently conducted, (ii) Liens arising under original purchase price conditional sales Contracts and equipment leases with third parties entered into in the ordinary course of business, (iii) title defects or Liens (other than those constituting Liens for the payment of Indebtedness), if any, that do not or would not, individually or in the aggregate, impair in any material respect the use or occupancy of the assets of such Person and its Subsidiaries, taken as a whole, (iv) Liens for Taxes that are not yet due or payable or that may thereafter be paid without penalty, (v) Liens supporting surety bonds, performance bonds and similar obligations issued in connection with the businesses of such Person and its Subsidiaries, (vi) Liens not created by such Person or its Subsidiaries that affect the underlying fee interest of a Company Leased Real Property, (vii) Liens that are disclosed on the most recent consolidated balance sheet of such Person included in its SEC Reports or notes thereto or securing liabilities reflected on such balance sheet, (viii) Liens arising under or pursuant to the organizational documents of such Person or any of its Subsidiaries, (ix) grants to others of rights-of-way, surface leases or crossing rights and amendments, modifications, and releases of rights-of-way, surface leases or crossing rights in the ordinary course of business, (x) with respect to rights-of-way, restrictions on the exercise of any of the rights under a granting instrument that are set forth therein or in another executed agreement, that is of public record or to which such Person or any of its Subsidiaries otherwise has access, between the parties thereto, (xi) Liens which an accurate up-to-date survey would show, (xii) Liens resulting from any facts or circumstances relating to, if such Person is the Company, Parent, Merger Sub or any of their Affiliates or, if such Person is Parent or Merger Sub, the Company or any of its Affiliates and (xiii) Liens that do not and would not reasonably be expected to materially impair the continued use of a Company Owned Real Property or a Company Leased Real Property as currently operated.

"Person" means an individual, corporation (including not-for-profit), Governmental Entity, general or limited partnership, limited liability company, joint venture, estate, trust, association, organization, unincorporated organization, other entity of any kind or nature or group (as defined in Section 13(d)(3) of the Exchange Act).

"Santee Cooper" means the South Carolina Public Service Authority, a body corporate and politic and agency of the State of South Carolina established under Chapter 31 of Title 58 of the Code of Laws of South Carolina, Annotated, as amended from time to time.

"Sarbanes-Oxley Act" means the Sarbanes-Oxley Act of 2002, as amended.

"SCBCA" means the South Carolina Business Corporation Act of 1988, as amended.

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"SCORS" means the South Carolina Office of Regulatory Staff, the administrative and regulatory body established under Title 58, Chapter 4 of the Code of Laws of South Carolina, Annotated, as amended from time to time.

"SCPSC" means the South Carolina Public Service Commission, the regulatory commission established under Title 58, Chapter 3 of the Code of Laws of South Carolina, Annotated, as amended from time to time.

"SCPSC Petition" means a petition to be filed jointly by the Company and Parent with the SCPSC for approval of the Merger and for approval of terms for cost recovery and other regulatory matters with respect to the NND Project, including the key terms summarized in Appendix A attached to this Agreement.

"SEC" means the United States Securities and Exchange Commission.

"SEC Reports" means all forms, statements, certifications, reports and other documents a Person is required or otherwise obligated to file or furnish with the SEC, including (i) those filed or furnished subsequent to the date of this Agreement and (ii) all exhibits and other information incorporated therein and all amendments and supplements thereto.

"Securities Act" means the Securities Act of 1933, as amended.

"Social Commitments" means the undertakings, terms, conditions, liabilities, obligations, commitments and sanctions set forth in Section 5.16.

"Source Material" means (i) uranium or thorium, or any combination thereof, in any physical or chemical form or (ii) ores that contain by weight one-twentieth of one percent (0.05%) or more of (A) uranium, (B) thorium or (C) any combination thereof.

"South Carolina Public Utility Laws" means the Laws of the State of South Carolina governing public utilities as contained in Title 58 of the Code of Laws of South Carolina, Annotated, as they may be amended from time, including the BLRA, the Laws providing for the organization, powers and terms of officials and members of the SCPSC and the SCORS, and the Laws providing for the establishment, review and adjustment of retail electric and natural gas rates and terms of conditions of service, as found in Title 58 of the Code of Laws of South Carolina, Annotated, in each case, as they may be amended from time to time.

"Special Nuclear Material" means plutonium, uranium-233, uranium enriched in the isotope-233 or in the isotope-235, and any other material that the NRC determines to be "Special Nuclear Material." Special Nuclear Material also refers to any material artificially enriched by any of the foregoing materials or isotopes. Special Nuclear Material does not include Source Material.

"Spent Nuclear Fuel" means fuel that has been withdrawn from a nuclear reactor following irradiation, and has not been chemically separated into its constituent elements by reprocessing. Spent Nuclear Fuel includes Special Nuclear Material, Byproduct Material, Source Material and other radioactive materials associated with nuclear fuel assemblies.

"Subsidiary" means, with respect to any Person, (i) any other Person (other than a partnership, joint venture or limited liability company) of which 50% or more of the total voting power of shares of stock or other equity interests entitled to vote in the election of directors, managers or trustees is at the time of determination owned or controlled, directly or indirectly, by such first Person and (ii) any partnership, joint venture or limited liability company of which (A) 50% or more of the capital accounts, distribution rights, total equity or voting interests or general or limited partnership interests, as applicable, are owned or controlled, directly or indirectly, by such Person, whether in the form of membership, general, special or limited partnership interests or otherwise or (B) such Person or any Subsidiary of such Person is a controlling general partner or otherwise controls such entity.
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"Superior Proposal" means an unsolicited bona fide written Acquisition Proposal relating to any direct or indirect acquisition or purchase of (i) assets that generate more than 50% of the consolidated total revenues or operating income of the Company and its Subsidiaries, taken as a whole, (ii) assets that constitute more than 50% of the consolidated total assets of the Company and its Subsidiaries, taken as a whole or (iii) more than 50% of the total voting power of the equity securities of the Company, in each case, that the Company Board determines in good faith after consultation with the Company's financial advisors and outside legal counsel is more favorable to the Company's shareholders than the Merger, taking into account the Person making the Acquisition Proposal and all legal, financial and regulatory aspects of the Acquisition Proposal (including the likelihood that such Acquisition Proposal would be consummated in accordance with its terms) and all other relevant circumstances.

"Tax Return" means any return, declaration, report, election, claim for refund or information return or any other statement or form filed or required to be filed with any Governmental Entity relating to Taxes, including any schedule or attachment thereto, and including any amendment thereof.

"Taxes" means all forms of taxes or duties imposed by any Governmental Entity, or required by any Governmental Entity to be collected or withheld, including charges, together with any related interest, penalties and other additional amounts.

"Willful Breach" means, with respect to any breach or failure to perform any of the covenants or other agreements contained in this Agreement, a breach that is a consequence of an act or failure to act undertaken by the breaching party with actual knowledge that such party's act or failure to act would result in or constitute a breach of this Agreement. For the avoidance of doubt, the failure of a party hereto to consummate the Closing when required pursuant to Section 1.02, or, on the Closing Date, cause the Effective Time to occur pursuant to Section 1.03, shall be a Willful Breach of this Agreement.

(b) Each of the following terms is defined in the Section set forth opposite such term:

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Term	Section
Agreement	Preamble
Alternative Acquisition Agreement	4.02(e)
Applicable Company SEC Reports	3.01(e)(i)
Applicable Parent SEC Reports	3.02(e)(i)
Articles of Merger	1.03
Book-Entry Share	2.01(a)
Cancelled Shares	2.01(b)
Certificate	2.01(a)
Changes	3.01(f)(i)
Closing	1.02
Closing Date	1.02
Company	Preamble
Company Adverse Recommendation Change	4.02(e)
Company Articles of Incorporation	3.01(a)
Company Board	Recitals
Company Board Recommendation	3.01(d)(i)
Company Bylaws	3.01(a)
Company Deferred Unit	2.02(c)
Company Employees	5.06(c)
Company Leased Real Property	3.01(o)(i)
Company Non-Union Employees	5.06(a)
Company Organizational Documents	3.01(a)
Company Owned Real Property	3.01(o)(ii)

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Annex B

[Morgan Stanley letterhead]

January 2, 2018

Board of Directors
SCANA Corporation
100 SCANA Parkway
Cayce, SC 29033

Members of the Board:

We understand that SCANA Corporation ("SCANA" or the "Company"), Dominion Energy, Inc. (the "Parent") and Sedona Corp., a wholly owned subsidiary of the Parent ("Acquisition Sub"), propose to enter into an Agreement and Plan of Merger, dated as of January 2, 2018 (the "Merger Agreement"), which provides, among other things, for the merger (the "Merger") of Acquisition Sub with and into the Company. Pursuant to the Merger, the Company will become a wholly owned subsidiary of the Parent, and each outstanding share of common stock, without par value, of the Company (the "Company Common Stock"), other than each share held by the Parent, Acquisition Sub or any other wholly owned subsidiary of the Parent and each share held by the Company or any wholly owned subsidiary of the Company (collectively, the "Excluded Shares"), will be converted into the right to receive 0.6690 shares (the "Merger Consideration," as such term is defined in the Merger Agreement) of common stock, without par value, of the Parent (the "Parent Common Stock"), subject to adjustment in certain circumstances. The terms and conditions of the Merger are more fully set forth in the Merger Agreement.

You have asked for our opinion as to whether the Merger Consideration to be received by the holders of shares of the Company Common Stock (other than the holders of the Excluded Shares) pursuant to the Merger Agreement is fair from a financial point of view to such holders of shares of the Company Common Stock.

For purposes of the opinion set forth herein, we have:

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1) Reviewed certain publicly available financial statements and other business and financial information of the Company and the Parent, respectively;
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2) Reviewed certain internal financial statements and other financial and operating data concerning the Company and the Parent, respectively;
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3) Reviewed certain financial projections prepared by the managements of the Company and the Parent, respectively;
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4) Discussed the past and current operations and financial condition and the prospects of the Company with senior executives of the Company;
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5) Discussed the past and current operations and financial condition and the prospects of the Parent with senior executives of the Parent;
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6) Reviewed the pro forma impact of the Merger on the Parent's earnings per share, cash flow, consolidated capitalization and certain financial ratios;
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7) Reviewed the reported prices and trading activity for the Company Common Stock and the Parent Common Stock;
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8) Compared the financial performance of the Company and the prices and trading activity of the Company Common Stock with that of certain other publicly-traded companies comparable with the Company, and their securities;
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9) Reviewed the financial terms, to the extent publicly available, of certain comparable acquisition transactions;

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10) Participated in certain discussions and negotiations among representatives of the Company and the Parent and their financial and legal advisors;

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11) Reviewed the Merger Agreement and certain related documents; and

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12) Performed such other analyses and considered such other factors as we have deemed appropriate.

We have assumed and relied upon, without independent verification, the accuracy and completeness of the information that was publicly available or supplied or otherwise made available to us by the Company and the Parent, and formed a substantial basis for this opinion. With respect to the financial projections, we have assumed that they have been reasonably prepared on bases reflecting the best currently available estimates and judgments of the respective managements of the Company and the Parent of the future financial performance of the Company and the Parent. In addition, we have assumed that the Merger will be consummated in accordance with the terms set forth in the Merger Agreement without any waiver, amendment or delay of any terms or conditions, including, among other things, that the Merger will be treated as a tax-free reorganization, pursuant to the Internal Revenue Code of 1986, as amended. We have relied upon, without independent verification, the assessment by the management of the Company of: (i) the timing and risks associated with the integration of the Company and the Parent; and (ii) their ability to retain key employees of the Company and the Parent, respectively. Morgan Stanley has assumed that in connection with the receipt of all the necessary governmental, regulatory or other approvals and consents required for the proposed Merger, no delays, limitations, conditions or restrictions will be imposed that would have a material adverse effect on the contemplated benefits expected to be derived in the proposed Merger (but we have assumed, without independent verification, the reasonableness of those delays, limitations, conditions and restrictions contained in the financial projections prepared by the managements of the Company and of the Parent). We are not legal, tax, or regulatory advisors. We are financial advisors only and have relied upon, without independent verification, the assessment of the Company and its legal, tax, and regulatory advisors with respect to legal, tax, and regulatory matters. For purposes of our analysis we have not made any assessment of the status of outstanding litigation or regulatory proceedings involving the Company and have excluded the effects of any such litigation or proceedings in our analysis, other than those effects included in the financial projections prepared by the managements of the Company and Parent, upon which we have relied without independent verification. We express no opinion with respect to the fairness of the amount or nature of the compensation to any of the Company's officers, directors or employees, or any class of such persons, relative to the Merger Consideration to be received by the holders of shares of the Company Common Stock (other than the holders of the Excluded Shares) in the transaction. We have not made any independent valuation or appraisal of the assets or liabilities of the Company or the Parent, nor have we been furnished with any such valuations or appraisals. Our opinion is necessarily based on financial, economic, market and other conditions as in effect on, and the information made available to us as of, the date hereof. Events occurring after the date hereof may affect this opinion and the assumptions used in preparing it, and we do not assume any obligation to update, revise or reaffirm this opinion.

In arriving at our opinion, we were not authorized to solicit, and did not solicit, interest from any party with respect to the acquisition, business combination or other extraordinary transaction, involving the Company. At the direction of the management and the Board of Directors of the Company, we did not negotiate with anyone other than the Parent.

We have acted as financial advisor to the Board of Directors of the Company in connection with this transaction and will receive a fee for our services, a substantial portion of which is contingent upon the closing of the Merger. In the two years prior to the date hereof, we and our affiliates have provided financing services to the Parent and have received fees for such services. Morgan Stanley may also seek to provide financial advisory and financing services to the Parent and the Company and their respective affiliates in the future and would expect to receive fees for the rendering of these services.

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Please note that Morgan Stanley is a global financial services firm engaged in the securities, investment management and individual wealth management businesses. Our securities business is engaged in securities underwriting, trading and brokerage activities, foreign exchange, commodities and derivatives trading, prime brokerage, as well as providing investment banking, financing and financial advisory services. Morgan Stanley, its affiliates, directors and officers may at any time invest on a principal basis or manage funds that invest, hold long or short positions, finance positions, and may trade or otherwise structure and effect transactions, for their own account or the accounts of its customers, in debt or equity securities or loans of the Parent, the Company, or any other company, or any currency or commodity, that may be involved in this transaction, or any related derivative instrument.

This opinion has been approved by a committee of Morgan Stanley investment banking and other professionals in accordance with our customary practice. This opinion is for the benefit and use of the senior management and the Board of Directors of the Company and, subject to the terms of the engagement letter, dated October 18, 2017, between the Company and Morgan Stanley, may not be used for any other purpose or disclosed without our prior written consent, except that a copy of this opinion may be included in its entirety in the Proxy Statement/Prospectus (as such term is defined in the Merger Agreement) to be filed with the Securities and Exchange Commission in connection with this transaction. This opinion does not address the relative merits of the transactions contemplated by the Merger Agreement as compared to other business or financial strategies that might be available to the Company, nor does it address the underlying business decision of the Company to enter into the Merger Agreement or proceed with any other transaction contemplated by the Merger Agreement. In addition, this opinion does not in any manner address the prices at which the Parent Common Stock will trade following consummation of the Merger or at any time and Morgan Stanley expresses no opinion or recommendation as to how the shareholders of the Company should vote at the shareholders' meeting to be held in connection with the Merger.

Based on and subject to the foregoing, we are of the opinion on the date hereof that the Merger Consideration to be received by the holders of shares of the Company Common Stock (other than the holders of the Excluded Shares) pursuant to the Merger Agreement is fair from a financial point of view to such holders of shares of the Company Common Stock.

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Very truly yours,

MORGAN STANLEY & CO., LLC

By: /s/ R. Todd Giardinelli
R. Todd Giardinelli
Managing Director

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Annex C

Opinion of RBC Capital Markets, LLC

January 2, 2018

The Board of Directors
SCANA Corporation
100 SCANA Parkway
Cayce, South Carolina 29033

The Board of Directors:

You have requested our opinion as to the fairness, from a financial point of view, to holders of the common stock of SCANA Corporation, a South Carolina corporation ("SCANA"), of the Merger Consideration (defined below) provided for pursuant to the terms and subject to the conditions set forth in an Agreement and Plan of Merger (the "Merger Agreement") proposed to be entered into among SCANA, Dominion Energy, Inc., a Virginia corporation ("Dominion Energy"), and Sedona Corp., a South Carolina corporation and wholly-owned subsidiary of Dominion Energy ("Merger Sub"). The Merger Agreement provides for, among other things, the merger of Merger Sub with and into SCANA (the "Merger") pursuant to which each outstanding share of the common stock, no par value per share, of SCANA ("SCANA Common Stock") will be converted into the right to receive 0.6690 of a share of the common stock, no par value per share, of Dominion Energy ("Dominion Energy Common Stock" and the implied per share value payable in the Merger utilizing such exchange ratio, the "Merger Consideration"). The terms and conditions of the Merger are set forth more fully in the Merger Agreement.

RBC Capital Markets, LLC ("RBCCM"), as part of our investment banking services, is regularly engaged in the valuation of businesses and securities in connection with mergers and acquisitions, corporate restructurings, underwritings, secondary distributions of listed and unlisted securities, private placements, and valuations for corporate and other purposes. In the ordinary course of business, RBCCM and/or certain of our affiliates may act as a market maker and broker in the publicly traded securities of SCANA, Dominion Energy and/or other entities involved in the Merger or their respective affiliates and receive customary compensation in connection therewith, and may also actively trade securities of SCANA, Dominion Energy and/or other entities involved in the Merger or their respective affiliates for our or our affiliates' own account or for the account of customers and, accordingly, RBCCM and our affiliates may hold a long or short position in such securities. We are acting as financial advisor to SCANA in connection with the Merger and we will receive a fee for our services, of which a portion is payable upon delivery of this opinion, a portion is payable upon receipt of approval of the Merger by holders of SCANA Common Stock and the principal portion is contingent upon consummation of the Merger. We also may be entitled to an additional fee payable, at SCANA's discretion, upon consummation of the Merger. In addition, SCANA has agreed to indemnify us for certain liabilities that may arise out of our engagement and to reimburse us for expenses incurred in connection with our services. As you are aware, RBCCM and certain of our affiliates in the past have provided, currently are providing and in the future may provide investment banking and commercial banking services to SCANA and/or its affiliates unrelated to the Merger, for which services RBCCM and our affiliates have received and expect to receive customary compensation, including, during the past two years, having acted or acting as a lender under certain credit facilities of SCANA. As you also are aware, RBCCM and certain of our affiliates in the past have provided, currently are providing and in the future may provide investment banking and commercial banking services to Dominion Energy and/or its affiliates, for which services RBCCM and its affiliates have received or expect to receive customary compensation, including, during the past two years, having acted or acting as (i) joint lead manager or joint book-running manager for certain debt and equity offerings of Dominion Energy and certain of its affiliates in 2016 and 2017, and (ii) joint lead arranger for, and as a lender under, certain bridge and other credit facilities of Dominion Energy and certain of its affiliates.

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The Board of Directors
SCANA Corporation
January 2, 2018

For purposes of rendering our opinion, we have undertaken such review, inquiries and analyses as we deemed necessary or appropriate under the circumstances, including the following:

(i) we reviewed the financial terms of a draft, dated January 2, 2018, of the Merger Agreement;

(ii) we reviewed certain publicly available financial and other information, and certain historical operating data, relating to SCANA and Dominion Energy made available to us from published sources and internal records of SCANA and Dominion Energy, respectively;

(iii) we reviewed certain financial projections and other estimates and data (including as to certain tax attributes) relating to SCANA prepared by the management of SCANA based on alternative regulatory settlement cases, and we reviewed certain financial projections and other estimates and data relating to Dominion Energy prepared by the management of Dominion Energy, which projections and other estimates and data we were directed by SCANA to utilize for purposes of our analyses and opinion;

(iv) we conducted discussions with members of the senior managements of SCANA and Dominion Energy with respect to the respective businesses, prospects and financial outlook of SCANA and Dominion Energy;

(v) we reviewed the reported prices and trading activity for shares of SCANA Common Stock and Dominion Energy Common Stock;

(vi) we compared certain financial metrics of SCANA and Dominion Energy with those of selected publicly traded companies in lines of businesses that we considered generally relevant in evaluating SCANA and Dominion Energy, respectively;

(vii) we reviewed certain potential pro forma financial effects of the Merger on Dominion Energy; and

(viii) we considered other information and performed other studies and analyses as we deemed appropriate.

In rendering our opinion, we have assumed and relied upon the accuracy and completeness of all information that was reviewed by us, including all financial, legal, tax, accounting, operating and other information provided to or discussed with us by or on behalf of SCANA or Dominion Energy (including, without limitation, financial statements and related notes), and upon the assurances of the respective managements and other representatives of SCANA and Dominion Energy that they are not aware of any relevant information that has been omitted or that remains undisclosed to us. We have not assumed responsibility for independently verifying and have not independently verified such information. We also have assumed that the financial projections and other estimates and data (including potential tax attributes relating to SCANA) that we were directed to utilize in our analyses were reasonably prepared on bases reflecting the best currently available estimates and good faith judgments of the respective managements of SCANA and Dominion Energy, as the case may be, as to the future financial performance of, and are a reasonable basis upon which to evaluate, SCANA under the alternative regulatory settlement cases reflected therein, Dominion Energy, the potential pro forma effects of the Merger and the other matters covered thereby. We express no opinion as to any such financial projections and other estimates and data or the assumptions upon which they are based. We have relied upon the assessments of the managements of SCANA and Dominion Energy as to, among other things, (i) the potential impact on SCANA and Dominion Energy of market, competitive, seasonal, and other trends and developments in and prospects for, and governmental, regulatory and legislative matters relating to or otherwise affecting, the utility, power and energy industries and the sectors of such industries and geographic regions in which SCANA and Dominion Energy operate (including, without limitation, with respect to future commodity prices and availability, which are subject to significant volatility, existing, planned and/or abandoned infrastructure and other capital projects, including the construction and abandonment of SCANA's new nuclear project in Jenkinsville, South Carolina, and pending and future rate cases, cost recovery and other regulatory proceedings and determinations) and assumptions of the managements of SCANA and Dominion Energy, respectively, as to

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such matters which, if different than as provided to us, could have a meaningful impact on our analyses or opinion, (ii) existing and future relationships, agreements and arrangements with, and the ability to attract, retain and/or replace, key employees, customers, suppliers, contractors and subcontractors and other commercial relationships of SCANA and Dominion Energy, and (iii) the ability to integrate the operations of SCANA and Dominion Energy. We have assumed that there will be no developments with respect to any of the foregoing that would have an adverse effect on SCANA, Dominion Energy or the Merger or that otherwise would be meaningful in any respect to our analyses or opinion.

In connection with our opinion, we have not assumed any responsibility to perform, and we have not performed, an independent valuation or appraisal of any of the assets or liabilities (contingent, off-balance sheet, accrued, derivative or otherwise) of or relating to SCANA, Dominion Energy or any other entity and we have not been furnished with any such valuations or appraisals. We express no view or opinion as to the potential impact on SCANA, Dominion Energy or any other entity of any pending or potential litigation, claims or governmental, regulatory or other proceedings or investigations. We have not assumed any obligation to conduct, and we have not conducted, any physical inspection of the property or facilities of SCANA, Dominion Energy or any other entity. We have not evaluated the solvency or fair value of SCANA, Dominion Energy or any other entity under any state, federal or other laws relating to bankruptcy, insolvency or similar matters. We have assumed that the Merger will be consummated in accordance with the terms of the Merger Agreement and in compliance with all applicable laws, documents and other requirements, without waiver, modification or amendment of any material term, condition or agreement, and that, in the course of obtaining the necessary governmental, regulatory or third party approvals, consents, releases, waivers and agreements for the Merger, no delay, limitation, restriction or condition will be imposed or occur, including any divestiture or other requirements, that would have an adverse effect on SCANA, Dominion Energy or the Merger or that otherwise would be meaningful in any respect to our analyses or opinion. We also have assumed that the Merger will qualify as a reorganization within the meaning of Section 368(a) of the Internal Revenue Code of 1986, as amended, for U.S. federal income tax purposes and otherwise qualify for the intended tax treatment contemplated by the Merger Agreement. In addition, we have assumed that the final executed Merger Agreement will not differ, in any respect meaningful to our analyses or opinion, from the draft that we reviewed.

Our opinion speaks only as of the date hereof, is based on conditions as they exist and information supplied or reviewed as of the date hereof, and is without regard to any market, economic, financial, legal, regulatory or other circumstances or event of any kind or nature which may exist or occur after such date. We have not undertaken and have no obligation to reaffirm, revise or update this opinion or otherwise comment upon events occurring after the date hereof with respect to this opinion. We are not expressing any opinion as to the actual value of Dominion Energy Common Stock when issued in connection with the Merger or the price or range of prices at which SCANA Common Stock, Dominion Energy Common Stock or any other securities of SCANA or Dominion Energy may trade or otherwise be transferable at any time, including following announcement or consummation of the Merger. As you are aware, the credit, financial and stock markets, and the industries in which SCANA and Dominion Energy operate, have experienced and continue to experience volatility and we express no opinion or view as to any potential effects of such volatility on SCANA or Dominion Energy (or their respective businesses) or the Merger.

The advice (written or oral) of RBCCM and our opinion expressed herein is provided for the benefit, information and assistance of the Board of Directors of SCANA (in its capacity as such) in connection with its evaluation of the Merger. We express no opinion and make no recommendation to any shareholder as to how such shareholder should vote or act with respect to the Merger or any proposal to be voted upon in connection with the Merger or otherwise.
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Our opinion addresses the fairness, from a financial point of view and as of the date hereof, of the Merger Consideration (to the extent expressly specified herein), without regard to individual circumstances of specific holders that may distinguish such holders or the securities of SCANA held by such holders. Our opinion does not in any way address any other terms, conditions, implications or other aspects of the Merger or the Merger Agreement, including, without limitation, the form or structure of the Merger, or any other agreement, arrangement or understanding to be entered into in connection with or contemplated by the Merger or otherwise. Our opinion also does not address the underlying business decision of SCANA to engage in the Merger or the relative merits of the Merger compared to any alternative business strategy or transaction that may be available to SCANA or in which SCANA might engage. We do not express any opinion or view with respect to, and we have relied upon the assessments of SCANA and its representatives regarding, legal, regulatory, tax, accounting and similar matters (including changes resulting from, and the impact of, the recent U.S. tax reform), as to which we understand that SCANA has obtained such advice as it deemed necessary from qualified professionals. Further, in rendering our opinion, we do not express any view on, and our opinion does not address, the fairness of the amount or nature of the compensation (if any) or other consideration to any officers, directors or employees of any party, or class of such persons, relative to the Merger Consideration or otherwise. In connection with our engagement, we were not requested to, and we did not, undertake a third-party solicitation process on SCANA's behalf with respect to the acquisition of all or a part of SCANA.

The issuance of our opinion has been approved by RBCCM's Fairness Opinion Committee.

Based on our experience as investment bankers and subject to the foregoing, including the various assumptions and limitations set forth herein, it is our opinion that, as of the date hereof, the Merger Consideration to be received by holders of SCANA Common Stock pursuant to the Merger Agreement is fair, from a financial point of view, to such holders.

Very truly yours,

RBC CAPITAL MARKETS, LLC

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

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Item 20. Indemnification of Directors and Officers.

Article VI of the Dominion Energy charter mandates indemnification of its directors and officers to the full extent permitted by the VSCA, and any other applicable law. The VSCA permits a corporation to indemnify its directors and officers against liability incurred in all proceedings, including derivative proceedings, arising out of their service to the corporation or to other corporations or enterprises that the officer or director was serving at the request of the corporation, except in the case of willful misconduct or a knowing violation of a criminal law. Dominion Energy is required to indemnify its directors and officers in all such proceedings if they have not violated this standard. Dominion Energy has also entered into agreements relating to the advancement of expenses for certain of its directors and officers in advance of a final disposition of proceedings or the making of any determination of eligibility for indemnification pursuant to the Dominion Energy charter.

In addition, Article VI of the Dominion Energy charter limits the liability of its directors and officers to the full extent permitted by the VSCA as now and hereafter in effect. The VSCA places a limit on the liability of a director or officer in derivative or shareholder proceedings equal to the lesser of (i) the amount specified in the corporation's articles of incorporation or a shareholder-approved bylaw; or (ii) the greater of (a) $100,000 or (b) twelve months of cash compensation received by the director or officer. The limit does not apply in the event the director or officer has engaged in willful misconduct or a knowing violation of a criminal law or a federal or state securities law. The effect of the Dominion Energy charter, together with the VSCA, is to eliminate liability of directors and officers for monetary damages in derivative or shareholder proceedings so long as the required standard of conduct is met.

Dominion Energy has purchased directors' and officers' liability insurance policies. Within the limits of their coverage, the policies insure (1) the directors and officers of Dominion Energy against certain losses resulting from claims against them in their capacities as directors and officers to the extent that such losses are not indemnified by Dominion Energy and (2) Dominion Energy to the extent that it indemnifies such directors and officers for losses as permitted under the laws of Virginia.

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Item 21. Exhibits and Financial Statement Schedules.

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Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of January 2, 2018, by and among Dominion Energy, Inc., Sedona Corp. and SCANA Corporation (included as Annex A to the proxy statement/prospectus that forms a part of this Registration Statement on Form S-4)†
5.1*	Opinion of McGuireWoods LLP regarding validity of the securities being registered
8.1*	Opinion of Morgan, Lewis & Bockius LLP regarding certain tax matters
8.2*	Opinion of Mayer Brown LLP regarding certain tax matters
23.1	Consent of Deloitte & Touche LLP, Independent Registered Public Accounting Firm for Dominion Energy
23.2	Consent of Deloitte & Touche LLP, Independent Registered Public Accounting Firm for SCANA Corporation
23.3*	Consent of McGuireWoods LLP (included in Exhibit 5.1)
23.4*	Consent of Morgan, Lewis & Bockius LLP (included in Exhibit 8.1)
23.5*	Consent of Mayer Brown LLP (included in Exhibit 8.2)

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Exhibit Number	Description
99.1*	Form of Proxy for SCANA Corporation
99.2	Consent of Morgan Stanley & Co. LLC
99.3	Consent of RBC Capital Markets, LLC

* To be filed by amendment.

† Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule will be furnished supplementally to the Securities and Exchange Commission upon request.

Item 22. Undertakings.

(a) The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by Section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement. Notwithstanding the foregoing, any increase or decrease in volume of securities offered (if the total dollar value of securities offered would not exceed that which was registered) and any deviation from the low or high end of the estimated maximum offering range may be reflected in the form of prospectus filed with the Securities and Exchange Commission pursuant to Rule 424(b) if, in the aggregate, the changes in volume and price represent no more than 20 percent change in the maximum aggregate offering price set forth in the "Calculation of Registration Fee" table in the effective registration statement; and

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement, or any material change to such information in the registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered that remain unsold at the termination of the offering.

(4) That, for the purpose of determining liability under the Securities Act of 1933 to any purchaser:

(i) Each prospectus filed by the registrant pursuant to Rule 424(b)(3) shall be deemed to be part of the registration statement as of the date the filed prospectus was deemed part of and included in the registration statement; and

(ii) Each prospectus required to be filed pursuant to Rule 424(b)(2), (b)(5) or (b)(7) as part of a registration statement in reliance on Rule 430B relating to an offering made pursuant to Rule 415(a)(1)(i), (vii) or (x) for the purpose of providing the information required by Section 10(a) of the Securities Act shall be deemed to be part of and included in the registration statement as of the earlier of the date such form of prospectus is first used after effectiveness or the date of the first contract of sale of securities in the offering described in the prospectus. As provided in Rule 430B, for liability purposes of the issuer and any person that is at that date an underwriter, such date shall be deemed to be a new effective date of the registration statement relating to the securities in the registration statement to which that prospectus relates, and the offering of such securities at that

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time shall be deemed to be the initial bona fide offering thereof. Provided, however, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such effective date, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such effective date.

(5) That, for the purpose of determining liability of the registrant under the Securities Act of 1933 to any purchaser in the initial distribution of the securities the undersigned registrant undertakes that in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(i) Any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

(iii) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and

(iv) Any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.

(b) The undersigned registrant hereby further undertakes that, for purposes of determining any liability under the Securities Act of 1933, each filing of the registrant's annual report pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 that is incorporated by reference in the registration statement shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(c) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrant pursuant to the provisions described under Item 15 in the registration statement above, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted against the registrant by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(d) The undersigned registrant hereby undertakes to respond to requests for information that is incorporated by reference into the prospectus pursuant to Items 4, 10(b), 11, or 13 of this Form, within one business day of receipt of such request, and to send the incorporated documents by first class mail or other equally prompt means. This includes information contained in documents filed subsequent to the effective date of the registration statement through the date of responding to the request.

(e) The undersigned registrant hereby undertakes to supply by means of a post-effective amendment all information concerning a transaction, and the company being acquired involved therein, that was not the subject of and included in the registration statement when it became effective.

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SIGNATURES

Pursuant to the requirements of the Securities Act, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Richmond, the Commonwealth of Virginia, on February 14, 2018.

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Dominion Energy, Inc.

By: /s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chairman, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed by the following persons in the capacities indicated and on the dates indicated. The officers and directors whose signatures appear below hereby constitute Carlos M. Brown, Carter M. Reid, or Morenike K. Miles, any one of whom may act, as their true and lawful attorneys-in-fact, with full power to sign on their behalf individually and in each capacity stated below and file all amendments and post-effective amendments to the registration statement making such changes in the registration statement as the registrant deems appropriate, and file any registration statement registering additional securities, and generally to do all things in their name in their capacities as officers and directors to enable the registrant to comply with the provisions of the Securities Act of 1933 and all requirements of the Securities and Exchange Commission.

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Signature	Title	Date
/s/ Thomas F. Farrell, II Thomas F. Farrell, II	Chairman of the Board of Directors, President and Chief Executive Officer (Principal Executive Officer)	February 14, 2018
/s/ William P. Barr William P. Barr	Director	February 14, 2018
/s/ Helen E. Dragas Helen E. Dragas	Director	February 14, 2018
/s/ James O. Ellis, Jr. James O. Ellis, Jr.	Director	February 14, 2018
/s/ John W. Harris John W. Harris	Director	February 14, 2018
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 14, 2018
/s/ Mark J. Kington Mark J. Kington	Director	February 14, 2018
/s/ Joseph M. Rigby Joseph M. Rigby	Director	February 14, 2018

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Signature	Title	Date
/s/ Pamela J. Royal Pamela J. Royal	Director	February 14, 2018
/s/ Robert H. Spilman, Jr. Robert H. Spilman, Jr.	Director	February 14, 2018
/s/ Susan N. Story Susan N. Story	Director	February 14, 2018
/s/ Michael E. Szymanczyk Michael E. Szymanczyk	Director	February 14, 2018
/s/ Mark F. McGettrick Mark F. McGettrick	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 14, 2018
/s/ Michele L. Cardiff Michele L. Cardiff	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 14, 2018

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in this Registration Statement on Form S-4 of our reports dated February 28, 2017, relating to the consolidated financial statements of Dominion Energy, Inc. and its subsidiaries ("Dominion Energy"), and the effectiveness of Dominion Energy's internal control over financial reporting, appearing in the Annual Report on Form 10-K of Dominion Energy, Inc. and subsidiaries for the year ended December 31, 2016 and to the reference to us under the heading "Experts" in the proxy statement/prospectus, which is part of this Registration Statement.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 14, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in this Registration Statement on Form S-4 of Dominion Energy Inc. of our reports dated February 24, 2017, relating to the consolidated financial statements and financial statement schedule of SCANA Corporation and subsidiaries (the “Company”), and the effectiveness of the Company’s internal control over financial reporting, appearing in the Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2016, and to the reference to us under the heading “Experts” in the Proxy Statement/Prospectus, which is part of this Registration Statement.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
February 14, 2018

Exhibit 99.2

Consent of Morgan Stanley & Co. LLC

We hereby consent to the use in the Registration Statement of Dominion Energy, Inc. on Form S-4 and in the proxy statement/prospectus of SCANA Corporation, which is part of the Registration Statement, of our opinion dated January 2, 2018 appearing as Annex B to such proxy statement/prospectus, and to the description of such opinion and to the references to our name contained therein under the headings "Summary—Opinion of SCANA's Financial Advisors—Opinion of Morgan Stanley & Co. LLC", "The Merger—Background of the Merger", "The Merger—SCANA's Reasons for the Merger; Recommendation of the SCANA Board," "The Merger—Opinions of SCANA's Financial Advisors—Opinion of Morgan Stanley & Co. LLC". In giving the foregoing consent, we do not admit that we come within the category of persons whose consent is required under Section 7 of the Securities Act of 1933, as amended (the "Securities Act"), or the rules and regulations promulgated thereunder, nor do we admit that we are experts with respect to any part of such Registration Statement within the meaning of the term "experts" as used in the Securities Act or the rules and regulations promulgated thereunder.

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MORGAN STANLEY & CO. LLC

By: /s/ Rakesh Shankar
Rakesh Shankar
Executive Director

New York, New York
February 14, 2018

Exhibit 99.3

[LETTERHEAD OF RBC CAPITAL MARKETS, LLC]

The Board of Directors
SCANA Corporation
100 SCANA Parkway
Cayce, South Carolina 29033
The Board of Directors:

We hereby consent to the inclusion of our opinion letter, dated January 2, 2018, to the Board of Directors of SCANA Corporation ("SCANA"), as Annex C to, and reference to such opinion letter under the headings "SUMMARY — Opinions of SCANA's Financial Advisors — Opinion of RBC Capital Markets, LLC" and "THE MERGER — Opinions of SCANA's Financial Advisors— Opinion of RBC Capital Markets, LLC" in, the joint proxy statement/prospectus relating to the proposed merger involving SCANA and Dominion Energy, Inc. ("Dominion Energy"), which proxy statement/prospectus forms a part of the Registration Statement on Form S-4 of Dominion Energy (the "Registration Statement"). By giving such consent, we do not thereby admit that we are experts with respect to any part of such Registration Statement within the meaning of the term "expert" as used in, or that we come within the category of persons whose consent is required under, the Securities Act of 1933, as amended, or the rules and regulations of the Securities and Exchange Commission promulgated thereunder.

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Very truly yours,

/s/ RBC Capital Markets, LLC

RBC CAPITAL MARKETS, LLC

February 14, 2018

	12 Months Ended December 31,					
	2012	2013	2014	2015	2016	12 Months Ended September 30, 2017
a. % AFUDC to Income Before Interest Charges (Total Company) (1)	4.65%	5.04%	4.82%	4.22%	4.38%	5.03%
b. AFUDC Dollar Amount (Total Company) (2)	31,849,930	38,467,598	41,780,591	38,831,918	44,134,820	39,935,581
c. Operation Expenses:						
Total Power Production	1,053,006,396	980,131,968	1,062,844,833	894,610,291	826,290,529	854,696,984
Transmission	8,281,178	8,754,207	12,428,575	9,527,028	9,628,720	12,701,141
Distribution	13,054,301	13,738,070	14,665,292	15,691,637	15,271,036	17,049,179
Administration	206,900,295	213,899,517	222,988,367	223,788,067	248,846,854	235,264,060
d. Maintenance Expenses:						
Total Power Production	80,138,776	78,582,772	84,482,220	87,093,415	83,085,234	82,560,909
Transmission	9,306,009	9,621,712	9,278,138	8,456,341	8,343,397	8,033,598
Distribution	30,771,282	32,884,806	36,804,215	40,446,306	39,976,913	39,528,862
Administration	5,533,386	5,530,961	6,442,313	6,334,105	6,905,304	6,490,654
e. Historical Cost	8,780,697,010	8,706,754,545	8,929,454,080	9,089,270,009	9,323,538,931	9,561,057,482
Accumulated Depreciation	(3,267,400,560)	(3,299,898,177)	(3,518,157,722)	(3,579,007,387)	(3,671,697,231)	(3,766,225,025)
f. Capital Obtained Outside the U.S.	None	None	None	None	None	None

(1) Income before Interest includes a $210 million pre-tax impairment loss for the 12 Months Ended September 30, 2017 and a $1.118 billion pre-tax impairment loss for the 12 Months Ended December 31, 2017

(2) AFUDC is not calculated on a Retail only basis. Amounts reported are for Total SCE&G

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF FIRST CONTINUING AUDIT REQUEST
DOCKET NO. 2009-489-E

Q**uestion 1-5(a)**: Provide a list of individual electric generating plants as of the end of the twelve-months ending September 30, 2017. This list should include the capacity, actual total cost, type of fuel utilized and cost per kilowatt ("KW") of installed capacity.

RESPONSE NO. 1-5(a)

	* September 30, 2017 Capacity (MW)	Production Plant Accts 310 - 316; 320-325; 330-336; 340-346	Type of Fuel Used	Cost per KW of Installed Capacity
V.C. Summer Station (Two-Thirds)	647.0	$1,315,991,964	Nuclear	$2,034
Urquhart Steam	95.0	$118,719,792	Gas, Oil	$1,250
Urquhart Combined Cycle	458.0	$263,548,520	Gas, Oil	$575
Wateree	684.0	$891,114,383	Coal, Oil	$1,303
McMeekin	250.0	$190,151,933	Gas	$761
Canadys **	0.0	$5,598,726	Coal, Gas, Oil	
Cope	415.0	$544,740,570	Coal, Oil, Gas	$1,313
Jasper Steam	385.0	$107,368,217	Gas, Oil	$279
Jasper ICT	467.0	$400,445,440	Gas, Oil	$857
Parr ICTs	60.0	$12,446,920	Gas, Oil	$207
(3) Hardeeville ICT	9.0	$3,616,029	Oil	$402
Urquhart ICTs	87.0	$32,834,545	Gas, Oil	$377
Coit ICTs	26.0	$6,363,740	Gas, Oil	$245
Williams ICTs	34.0	$7,603,079	Gas, Oil	$224
Williams Steam	605.0	$696,061,176	Coil, Oil	$1,151
Hagood ICT	126.0	$56,331,778	Gas, Oil	$447
COGEN South	85.0	$11,144,060	Coal, Wood	$131
Parr Hydro	7.0	$12,776,362	Water	$1,825
Saluda Hydro (excluding Dam)	200.0	$54,359,651	Water	$272
Stevens Creek Hydro	9.0	$17,231,766	Water	$1,915
Fairfield Pumped Storage	576.0	$227,786,144	Water	$395
Neal Shoals Hydro	2.0	$10,626,632	Water	$5,313
Boeing	2.6	$9,362,981	Solar	$3,601

Note:
*** September 30, 2017 values are Net Summer Capacity Ratings.**

**** Canadys units are retired and the $5,598,726 represents the value of the land.**

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
South Carolina Electric & Gas Company	**End of** 2014/Q4

Deloitte.

Deloitte & Touche LLP

550 South Tryon Street
Suite 2500
Charlotte, NC 28202
USA

Tel: 704-887-1500
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying financial statements of South Carolina Electric & Gas Company (the "Company"), which comprise the balance sheet — regulatory basis as of December 31, 2014, and the related statements of income — regulatory basis, retained earnings — regulatory basis, and cash flows — regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

As discussed before Note 1 to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Restricted Use

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

April 17, 2015

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent South Carolina Electric & Gas Company	02 Year/Period of Report End of 2014/Q4
03 Previous Name and Date of Change *(if name changed during year)*	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 100 SCANA Parkway, Cayce, SC 29033-3712	
05 Name of Contact Person Lisa Honeycutt	06 Title of Contact Person Accounting Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 Operation Way - MC B131, Cayce, SC 29033-3701	

08 Telephone of Contact Person, *Including Area Code* (803) 217-7416	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Jimmy E. Addison 02 Title Executive Vice President and CFO	03 Signature Jimmy E. Addison	04 Date Signed *(Mo, Da, Yr)* 04/17/2015

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

James E. Swan, IV, Controller
100 SCANA Parkway
Cayce, SC 29033-3712

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

South Carolina - July 19, 1924

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

South Carolina - Electric, Gas

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2014/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

The respondent is a wholly-owned subsidiary of SCANA Corporation (SCANA). See below for SCANA's organizational structure.

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA holds directly all of the capital stock of the following subsidiaries, each of which is incorporated in South Carolina.

SOUTH CAROLINA ELECTRIC & GAS COMPANY (SCE&G) is engaged in the generation, transmission, distribution and sale of electricity to retail and wholesale customers and the purchase, sale and transportation of natural gas to retail customers.

SOUTH CAROLINA GENERATING COMPANY, INC. (GENCO) owns Williams Station and sells electricity solely to SCE&G.

SOUTH CAROLINA FUEL COMPANY, INC. (Fuel Company) acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission allowances.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED (PSNC Energy) purchases, sells and transports natural gas to retail customers.

CAROLINA GAS TRANSMISSION CORPORATION (CGT) transports natural gas in South Carolina and southeastern Georgia. In December 2014, SCANA announced that CGT would be sold to Dominion Resources, Inc. The sale closed at the end of January 2015.

SCANA COMMUNICATIONS, INC. (SCI) provides fiber optic communications, ethernet services and data center facilities and builds, manages and leases communications towers in South Carolina, North Carolina and Georgia. In December 2014, SCANA announced that SCI would be sold to Spirit Communications. The sale closed in February 2015.

SCANA ENERGY MARKETING, INC. (SEMI) markets natural gas, primarily in the Southeast, and provides energy-related risk management services. SCANA Energy, a division of SEMI, markets natural gas in Georgia's retail market.

SCANA SERVICES, INC. provides administrative, management and other services to SCANA's subsidiaries and business units.

SCANA owns two insiginificant energy-related companies that are being liquidated.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	South Carolina Fuel Company, Inc.	Acquires, owns, provides	None	
2		financing for and sells at		
3		cost to SCE&G nuclear fuel,		
4		certain fossil fuels and		
5		emission allowances.		
6				
7	South Carolina Generating Company, Inc.	Owns A.M. Williams	None	
8		Generating Station and sells		
9		electricity solely to SCE&G.		
10				
11				
12	SRFI, LLC	A single member LLC	None	
13		holding investments in		
14		companies involved with		
15		re-engineered fuel.		
16				
17	APOG, LLC	Provides technical,	None	
18		engineering and procurement		
19		support services to and for		
20		the benefit of members and		
21		their licensing, development		
22		and construction of AP1000		
23		nuclear power plants.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
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Definitions
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Canadys Refined Coal, LLC	Manufactures and sells	None	
2		refined coal to reduce		
3		emissions.		
4				
5	Brandon Shores Coaltech, LLC	Manufactures and sells	None	
6		refined coal to reduce		
7		emissions.		
8				
9	Louisa Refined Coal, LLC	Manufactures and sells	None	
10		refined coal to reduce		
11		emissions.		
12				
13	Carolinas Virginia Nuclear Power	A non-profit corporation	None	
14	Associates, Inc. (CVNPA)	formed in 1956 by member		
15		companies to jointly study		
16		economic ways to produce and		
17		utilize nuclear material and		
18		atomic energy. Operated a		
19		nuclear power plant from		
20		1963 - 1967.		
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Schedule Page: 103 Line No.: 1 Column: d

Control held by SCE&G under the terms of a fuel contract.

Schedule Page: 103 Line No.: 7 Column: d

SCE&G has determined that it has a controlling financial interest in South Carolina Generating Company, Inc. under the terms of a Power Purchase Agreement. Accordingly, SCE&G consolidates the accounts of South Carolina Generating Company, Inc. for financial reporting under Generally Accepted Accounting Principles. Since South Carolina Generating Company, Inc. is a separate FERC reporting entity and per guidance from FERC staff, South Carolina Generating Company, Inc. has not been consolidated in this Form 1 report.

Schedule Page: 103 Line No.: 12 Column: d

SRFI, LLC is a single member LLC in which SCE&G is the sole member and no stock was issued.

Schedule Page: 103 Line No.: 17 Column: d

SCE&G holds a 25% interest in APOG, LLC. Other members include Duke Energy, Southern Nuclear Operating Company and Florida Power & Light Company.

Schedule Page: 103.1 Line No.: 1 Column: d

SCE&G holds a 40% interest in Canadys Refined Coal, LLC. The other member is AJG Coal, Inc.

Schedule Page: 103.1 Line No.: 5 Column: d

SCE&G holds a 10% interest in Brandon Shores Coaltech, LLC. Other members include AJG Coal, Inc. and BSW Refined Coal.

Schedule Page: 103.1 Line No.: 9 Column: d

SCE&G holds a 10% interest in Louisa Refined Coal, LLC. Other members include AJG Coal, Inc. and LRC Holdings.

Schedule Page: 103.1 Line No.: 13 Column: d

SCE&G holds a 25% interest in CVNPA. Other members include Duke Power Company (Duke Energy Carolinas, LLC), Carolina Power & Light Company (Duke Energy Progress) and Virginia Electric and Power Company (Dominion Virginia Power).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	Chairman and Chief Executive Officer	Kevin B. Marsh	882,301
3	Chief Operating Officer and President of Generation		
4	& Transmission	Stephen A. Byrne	572,396
5	President of Retail Operations	W. Keller Kissam	355,230
6	President of Gas Operations	D. Russell Harris	170,899
7	Executive Vice President and		
8	Chief Financial Officer	Jimmy E. Addison	395,342
9	Senior Vice President of Fuel Procurement,		
10	Asset Management and (Effective 5/14)		
11	Power Marketing	Sarena D. Burch	222,454
12	Senior Vice President, General Counsel		
13	and Assistant Secretary	Ronald T. Lindsay	290,757
14	Senior Vice President Administration	Martin K. Phalen	215,972
15	Senior Vice President and Chief Nuclear Officer	Jeffrey B. Archie	347,622
16	Senior Vice President of Governmental Affairs		
17	and Economic Development (Retired 10/14)	Charles B. McFadden	260,051
18	Vice President of Rates and Regulatory		
19	Services (1/14 - 10/14)		
20	Senior Vice President of Economic Development,		
21	Governmental & Regulatory		
22	Affairs (Effective 10/14)	Kenneth R. Jackson	233,209
23	Vice President of Governmental Affairs (Effective 5/14)	Henry E. Barton, Jr.	118,940
24	Vice President of Human Resources (Effective 9/14)	Annmarie C. Higgins	55,654
25	Vice President of Marketing and Communications	Catherine B. Love	160,373
26	Vice President of Electric Operations	William J. Turner III	201,376
27	Vice President of Gas Operations	Felicia R. Howard	196,343
28	Vice President of Fossil Hydro	James M. Landreth	240,357
29	Vice President of Customer Relations and		
30	Renewables	Daniel F. Kassis	204,197
31	Vice President of Customer Service	Samuel L. Dozier	201,142
32	Vice President of Operations Support (Through 1/14)		
33	Vice President of SCANA Support		
34	Services (Effective 1/14)	Stacy O. Shuler, Jr	176,522
35	Vice President of Electric Transmission (Effective 1/14)	Pandelis N. Xanthakos	161,069
36	Vice President of Nuclear Operations	Thomas D. Gatlin	285,155
37	Vice President of New Nuclear Operations	Ronald A. Jones	331,518
38	Vice President of Nuclear Financial Administration	Carlette L. Walker	244,034
39	Treasurer and Risk Management Officer	Mark R. Cannon	182,329
40	Secretary	Gina S. Champion	148,553
41	Controller	James E. Swan, IV	180,049
42	Chief Information Officer	Randal M. Senn	207,246
43			
44			

Schedule Page: 104 Line No.: 1 Column: c

Amounts reported reflect the portion of the Officer's base salary that was assigned to the respondent during the reporting period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	J.A. Bennett	Columbia, South Carolina
2	J.F.A.V. Cecil	Asheville, North Carolina
3	D. M. Hagood	Charleston, South Carolina
4	J.M. Micali	Boston, Massachusetts
5	L.M. Miller***	Great Falls, Virginia
6	J.W. Roquemore	Orangeburg, South Carolina
7	M.K. Sloan***	Durham, North Carolina
8	H. C. Stowe***	Pawleys Island, South Carolina
9	A. Trujillo	Atlanta, Georgia
10	K.B. Marsh, Chairman	
11	and Chief Executive Officer of	
12	SCANA Corporation and SCE&G **	Cayce, South Carolina
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes
[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Schedule 1, Schedule 7, Schedule 8, Attachment H	ER10-516
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20140515-5275	05/15/2014	ER10-516	Annual Update Informational Filing	Schedule 1, 7, 8, Attachment H
2					
3					
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. One twenty year muncipal electric franchise agreement was renewed during the second quarter of 2014 without payment of consideration.

2. None

3. None

4. None

5. None

6. The Company's obligation under short-term borrowing arrangements on the respective Balance Sheet dates were as follows:

12/31/2014	12/31/2013
$708,647,000	$251,264,000

Such short-term borrowings have been authorized by FERC (Docket No. ES12-53-000 and Docket No. ES14-48-00).

In October 2014, SCE&G extended its existing five-year credit agreement. See Note 4 to the Financial Statements for additional information. (FERC Docket Nos. ES12-53-000, ES14-48-000 and SCPSC Docket No. 2012-322-E).

In 2014, the Company borrowed $314,087,861 and paid back $297,300,000 from the SCANA Utility Money Pool. At 12/31/2014, Fuel Company had $16,787,861 of borrowings outstanding and SCE&G had $80,000,000 invested in the SCANA Utility Money Pool.

In May 2014, SCE&G issued $300 million of 4.5% First Mortgage Bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Such long-term borrowings have been authorized by the SCPSC (Docket No. 2013-132-E).

For additional information, see Notes 4, 6 and 7 to the Financial Statements.

7. None

8. None

9. See Notes 2 and 10 to the Financial Statements.

10. None

11. (Reserved)

12. Not Applicable

13. The following changes in Company Officers and Directors became effective during 2014:

John F.A.V. Cecil and Alfredo Trujillo were appointed to the Company's Board of Directors.

Pandelis N. Xanthakos was appointed Vice President of Electric Transmission.

Caryl J. Kuchman vacated the position of Corporate Compliance and Internal Auditing Officer to assume a position within SCANA's Human Resources Department.

James P. Hudson vacated the position of Vice President of Human Resources and assumed a position within SCANA's Corporate Compliance Department.

Stacy O. Shuler, Jr., formerly SCE&G Vice President - Operations Support, was appointed Vice President - SCANA Support Services.

Henry E. Barton, Jr. was appointed Vice President - Governmental Affairs

M. Shaun Randall was appointed Vice President - Gas Services.

Sarena D. Burch current Senior Vice President of Fuel Procurement and Asset Management was also appointed Senior Vice President - Power Marketing.

Annmarie C. Higgins was appointed Vice President of Human Resources.

Charles B. McFadden, Senior Vice President of Governmental Affairs and Economic Development retired.

Kenneth R. Jackson, formerly Vice President - Rates and Regulatory Services, was appointed Senior Vice President of Economic Development, Governmental & Regulatory Affairs.

14. Not Applicable

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	10,240,705,596	9,971,880,984
3	Construction Work in Progress (107)	200-201	3,295,945,264	2,680,577,368
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		13,536,650,860	12,652,458,352
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,061,048,465	3,749,408,476
6	Net Utility Plant (Enter Total of line 4 less 5)		9,475,602,395	8,903,049,876
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	132,721,361	136,633,663
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		116,157,676	115,386,817
9	Nuclear Fuel Assemblies in Reactor (120.3)		222,874,273	219,655,819
10	Spent Nuclear Fuel (120.4)		598,661,721	533,846,170
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	741,106,879	695,877,789
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		329,308,152	309,644,680
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,804,910,547	9,212,694,556
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		68,466,914	70,263,805
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,060,728	1,028,820
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		2,177,912	2,219,362
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		122,653,840	197,769,462
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	19,124,880
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		192,237,938	288,348,689
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		97,217,327	86,659,397
36	Special Deposits (132-134)		99,118,583	117,973
37	Working Fund (135)		84,051	83,276
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		250,112,474	237,431,592
41	Other Accounts Receivable (143)		193,324,597	89,388,378
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,572,212	3,027,925
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		95,139,393	3,798,854
45	Fuel Stock (151)	227	68,741,416	84,448,877
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	121,215,971	112,200,631
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	675,532	956,575

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	8	0
55	Gas Stored Underground - Current (164.1)		20,698,970	15,696,155
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		9,606,007	9,236,569
57	Prepayments (165)		68,681,531	63,771,867
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		115,840,005	111,923,807
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	32,580,164
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	19,124,880
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,136,883,653	826,141,310
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		28,445,789	26,174,255
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	137,617,628	144,613,746
72	Other Regulatory Assets (182.3)	232	1,629,813,402	1,185,371,007
73	Prelim. Survey and Investigation Charges (Electric) (183)		115,044	55,543
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	86,416,963	84,954,912
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		17,687,903	19,706,929
82	Accumulated Deferred Income Taxes (190)	234	286,877,391	352,113,679
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,186,974,120	1,812,990,071
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		13,321,006,258	12,140,174,626

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2014/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	576,405,122	576,405,122
3	Preferred Stock Issued (204)	250-251	100,000	100,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,987,672,935	1,906,887,129
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	4,335,379	4,335,379
11	Retained Earnings (215, 215.1, 216)	118-119	2,077,189,755	1,896,360,528
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-3,146,214	-2,614,921
16	Total Proprietary Capital (lines 2 through 15)		4,633,886,219	4,372,802,479
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	3,928,770,000	3,628,770,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	100,203,972	103,171,169
22	Unamortized Premium on Long-Term Debt (225)		25,619,188	26,232,307
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		19,999,788	18,051,246
24	Total Long-Term Debt (lines 18 through 23)		4,034,593,372	3,740,122,230
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		10,772,461	9,698,155
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,338,743	4,462,988
29	Accumulated Provision for Pensions and Benefits (228.3)		196,649,207	173,202,179
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		17,248,442	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		521,027,126	532,379,558
35	Total Other Noncurrent Liabilities (lines 26 through 34)		749,035,979	719,742,880
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		708,647,000	251,264,000
38	Accounts Payable (232)		284,424,409	233,218,153
39	Notes Payable to Associated Companies (233)		16,787,861	0
40	Accounts Payable to Associated Companies (234)		94,663,510	87,328,172
41	Customer Deposits (235)		54,814,873	49,108,024
42	Taxes Accrued (236)	262-263	166,040,369	218,621,990
43	Interest Accrued (237)		62,813,355	61,731,273
44	Dividends Declared (238)		72,500,000	60,000,000
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		6,991,109	6,162,485
48	Miscellaneous Current and Accrued Liabilities (242)		73,352,764	66,556,609
49	Obligations Under Capital Leases-Current (243)		3,274,644	2,653,327
50	Derivative Instrument Liabilities (244)		224,303,955	882,564
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		17,248,442	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,751,365,407	1,037,526,597
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	25,951,600	29,519,200
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	75,473,817	69,803,534
60	Other Regulatory Liabilities (254)	278	119,704,334	380,522,773
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	10,509,025	8,649,325
63	Accum. Deferred Income Taxes-Other Property (282)		1,518,007,215	1,397,131,108
64	Accum. Deferred Income Taxes-Other (283)		402,479,290	384,354,500
65	Total Deferred Credits (lines 56 through 64)		2,152,125,281	2,269,980,440
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		13,321,006,258	12,140,174,626

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,091,428,231	2,844,824,980		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,655,465,370	1,518,557,424		
5	Maintenance Expenses (402)	320-323	145,271,659	135,239,110		
6	Depreciation Expense (403)	336-337	267,952,165	276,755,891		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	9,028,136	9,714,181		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	860,418	860,418		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		18,061,442	7,875,310		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,061,940			
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	201,595,140	194,140,138		
15	Income Taxes - Federal (409.1)	262-263	37,221,716	135,401,516		
16	- Other (409.1)	262-263	-4,796,877	21,413,040		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	421,394,100	323,947,484		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	242,370,067	300,267,632		
19	Investment Tax Credit Adj. - Net (411.4)	266	-3,567,600	-3,567,600		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,507,177,542	2,320,069,280		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		584,250,689	524,755,700		

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,629,218,129	2,430,445,696	462,210,102	414,379,284			2
						3
1,312,927,067	1,216,523,762	342,536,971	302,032,159	1,332	1,503	4
137,006,886	126,620,251	8,264,773	8,618,859			5
243,300,173	252,777,107	24,651,992	23,978,784			6
						7
7,992,210	8,579,971	1,035,926	1,134,210			8
854,201	854,201	6,217	6,217			9
18,061,442	7,875,310					10
						11
1,061,940						12
						13
178,478,738	172,940,958	23,116,416	21,199,180	-14		14
26,658,600	126,926,116	10,563,516	8,476,100	-400	-700	15
-7,572,800	20,336,540	2,776,023	1,076,500	-100		16
396,817,100	293,306,484	24,577,000	30,641,000			17
223,430,032	273,873,232	18,940,035	26,394,400			18
-2,288,400	-2,288,400	-1,279,200	-1,279,200			19
						20
						21
						22
						23
						24
2,089,867,125	1,950,579,068	417,309,599	369,489,409	818	803	25
539,351,004	479,866,628	44,900,503	44,889,875	-818	-803	26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		584,250,689	524,755,700		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		4,678,010	62,367		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,148,936	141,453		
33	Revenues From Nonutility Operations (417)		28,800	317,336		
34	(Less) Expenses of Nonutility Operations (417.1)		881,007	489,466		
35	Nonoperating Rental Income (418)		120,511	111,101		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		-1,663,204	-930,999		
38	Allowance for Other Funds Used During Construction (419.1)		27,737,866	25,143,291		
39	Miscellaneous Nonoperating Income (421)		70,992,261	53,184,479		
40	Gain on Disposition of Property (421.1)		273,925	260,141		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		98,138,226	77,516,797		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		33,834	33,834		
45	Donations (426.1)		8,333,437	3,696,569		
46	Life Insurance (426.2)		-281,910	-231,551		
47	Penalties (426.3)		43,000	-11,336		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,520,473	1,391,620		
49	Other Deductions (426.5)		13,044,079	11,170,108		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		22,692,913	16,049,244		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	746,297	400,227		
53	Income Taxes-Federal (409.2)	262-263	1,788,036	10,091,960		
54	Income Taxes-Other (409.2)	262-263	-1,941,466	-7,296,098		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	8,755,000	-1,458,100		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,112,929	-4,355,126		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		4,234,938	6,093,115		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		71,210,375	55,374,438		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		209,983,057	199,160,491		
63	Amort. of Debt Disc. and Expense (428)		2,815,605	2,478,004		
64	Amortization of Loss on Reaquired Debt (428.1)		2,019,026	2,023,653		
65	(Less) Amort. of Premium on Debt-Credit (429)		613,119	584,183		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		6,556,721	6,798,991		
68	Other Interest Expense (431)		3,413,273	3,267,839		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		14,042,726	13,324,307		
70	Net Interest Charges (Total of lines 62 thru 69)		210,131,837	199,820,488		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		445,329,227	380,309,650		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		445,329,227	380,309,650		

Schedule Page: 114 Line No.: 4 Column: g

Includes depreciation charges of $7,808,322, amortization charges of $2,497,135 and property taxes of $1,869,404 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: h

Includes depreciation charges of $5,276,663, amortization charges of $2,742,482 and property taxes of $1,858,362 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: i

Includes depreciation charges of $873,590, amortization charges of $218,807 and property taxes of $163,780 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: j

Includes depreciation charges of $739,079, amortization charges of $245,551 and property taxes of $166,723 billed from SCANA Services.

Schedule Page: 114 Line No.: 39 Column: c

In SCPSC Docket No. 2013-382-E, the SCPSC authorized the Company to utilize gains from the settlement of existing interest rate derivatives for the benefit of its customers through offsetting fuel costs. Accordingly, in 2014 the Company recognized $46,436,829 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue to reduce the Company's undercollected fuel costs.

In addition, in SCPSC Docket No. 2014-44-E, the SCPSC authorized the Company to utilize interest rate derivative settlement gains to offset certain Lost Revenue amounts related to the Company's DSM Program for which recovery had been deferred. Accordingly, during 2014 the Company recognized $4,964,918 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue as a result of the Company writing off the related receivable.

The order also authorized the Company to utilize interest rate derivative settlement gains to stabilize the ongoing DSM Lost Revenues through May 2015. Accordingly, during 2014 the Company recognized $12,601,958 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue.

Schedule Page: 114 Line No.: 39 Column: d

In SCPSC Docket No. 2013-382-E, the SCPSC authorized the Company to utilize gains from the settlement of existing interest rate derivatives for the benefit of its customers through offsetting fuel costs. Accordingly, in 2013 the Company recognized $41,645,809 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue to reduce the Company's undercollected fuel costs.

In addition, in SCPSC Docket No. 2012-218-E, the SCPSC authorized the Company to utilize interest rate derivative settlement gains to offset certain undercollected amounts related to the termination of the Company's eWNA program. Accordingly, during 2013 the Company recognized $8,461,020 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue as a result of the Company writing off the related receivable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,833,229,781	1,705,078,069
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		445,329,227	380,309,650
17	Appropriations of Retained Earnings (Acct. 436)			
18	See Note 3 to Financial Statements	215.1	-4,558,225	(2,157,938)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-4,558,225	(2,157,938)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31		238	-264,500,000	(250,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-264,500,000	(250,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,009,500,783	1,833,229,781
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		67,688,972	63,130,747
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		67,688,972	63,130,747
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,077,189,755	1,896,360,528
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	445,329,227	380,309,650
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	268,165,140	276,935,729
5	Amortization of Utility Plant and Acquisition Adjustment	9,922,388	10,608,433
6	Amortization - Muni Franchise, Unrecovered Plt & OCI	18,233,861	8,171,188
7	Amortization of Nuclear Fuel	45,229,090	57,084,765
8	Deferred Income Taxes (Net)	205,942,585	36,611,268
9	Investment Tax Credit Adjustment (Net)	-3,567,600	-3,567,600
10	Net (Increase) Decrease in Receivables	-122,611,335	6,790,573
11	Net (Increase) Decrease in Inventory	-42,399,578	22,482,180
12	Net (Increase) Decrease in Allowances Inventory	281,043	630,573
13	Net Increase (Decrease) in Payables and Accrued Expenses	-31,734,838	75,269,288
14	Net (Increase) Decrease in Other Regulatory Assets	-338,118,110	60,831,466
15	Net Increase (Decrease) in Other Regulatory Liabilities	-125,206,510	67,203,261
16	(Less) Allowance for Other Funds Used During Construction	27,737,866	25,143,291
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	326,065,464	-155,244,582
19	Discount / Premium on Long-Term Debt	-146,520	-116,858
20	Carrying Cost Recovery	-9,077,954	-2,922,670
21	(Gain) / Loss on Disposition of Assets	-1,000,635	-260,141
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	617,567,852	815,673,232
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-932,065,147	-902,333,380
27	Gross Additions to Nuclear Fuel	-9,684,303	-103,052,590
28	Gross Additions to Common Utility Plant	-9,934,828	-14,988,344
29	Gross Additions to Nonutility Plant	-5,114,270	-7,569,840
30	(Less) Allowance for Other Funds Used During Construction	-27,737,866	-25,143,291
31	Other (provide details in footnote):		
32	Salvage Received	6,229,336	8,277,682
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-922,831,346	-994,523,181
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Proceeds from Sale of Fixed Assets	6,116,921	1,354,373
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Industrial Revenue Bond Proceeds from Trust		56,650,958
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Investment to Trust - Industrial Revenue Bonds		-56,650,958
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Short-term Investing from Money Pool	-80,000,000	
54	Other Investments	-106,473,527	19,087,687
55	Settlement of Interest Rate Swaps	-94,677,082	114,005,223
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,197,865,034	-860,075,898
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	300,000,000	454,857,383
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Contributions from Parent	88,001,576	313,176,223
66	Net Increase in Short-Term Debt (c)	457,383,000	
67	Other (provide details in footnote):		
68	Deferred Financing Costs / Long-Term Debt Issuance Costs	-6,582,313	-4,369,721
69	Short-term Borrowing from Utility Money Pool	314,087,861	
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,152,890,124	763,663,885
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-6,004,684	-243,942,308
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Short-term Borrowings from Utility Money Pool	-297,300,000	
78	Net Decrease in Short-Term Debt (c)		-197,804,000
79	Contributions to Parent	-6,729,553	-2,383,666
80	Dividends on Preferred Stock		-93
81	Dividends on Common Stock	-252,000,000	-234,250,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	590,855,887	85,283,818
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	10,558,705	40,881,152
87			
88	Cash and Cash Equivalents at Beginning of Period	86,742,673	45,861,521
89			
90	Cash and Cash Equivalents at End of period	97,301,378	86,742,673

Schedule Page: 120 Line No.: 18 Column: b

Includes $109,912,772 for changes in the Company's net postretirement benefit obligation, $256,001,555 for the change in fair value of Derivative Instruments,($4,909,664) for Prepayments, ($37,894,053) for Cost of Removal and various other Balance Sheet changes not presented as separate line items.

Schedule Page: 120 Line No.: 18 Column: c

Includes ($104,617,747) for the change in fair value of Derivative Instruments, ($20,150,031) for Cost of Removal, changes associated with the Company's remeasurement of its pension obligation (See Note 8 to Financial Statements) and various other Balance Sheet changes not presented as separate line items.

Schedule Page: 120 Line No.: 26 Column: b

For the twelve months ended December 31, 2014, the Company added $3,428,555 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($1,589,135) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 26 Column: c

For the twelve months ended December 31, 2013, the Company added $3,013,220 to its Utility Plant Property Account (101) and reduced the same account by ($1,140,197) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: b

For the twelve months ended December 31, 2014, the Company added $223,952 to its Common Utility Plant Property Account (118) and reduced the same account by ($311,152) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: c

For the twelve months ended December 31, 2013, the Company added $168,981 to its Common Utility Plant Property Account (118) and reduced the same account by ($258,307) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: b

For the twelve months ended December 31, 2014, the Company added $1,080,603 to its Nonutility Property Account (121) and reduced the same account by ($1,137,201)for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: c

For the twelve months ended December 31, 2013, the Company added $598,803 to its Nonutility Property Account (121) and reduced the same account by ($2,217,379)for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 54 Column: b

Nuclear Decommissioning Trust	($ 1,770,905)
Investment in Refined Coal Partnerships	(5,702,012)
Collateral Returned - Interest Rate Swaps	252,600,134
Collateral Posted - Interest Rate Swaps	(351,318,213)
Withdrawals from Like Kind Exchange Escrow Account	106,993
Deposits to Like Kind Exchange Escrow Account	(389,524)
Total	($106,473,527)

Schedule Page: 120 Line No.: 54 Column: c

Nuclear Decommissioning Trust	($ 1,780,910)
Investment in Refined Coal Partnerships	(5,211,736)
Collateral Returned - Interest Rate Swaps	62,801,865
Collateral Posted - Interest Rate Swaps	(36,651,865)
Withdrawals from Like Kind Exchange Escrow Account	285,886
Deposits to Like Kind Exchange Escrow Account	(355,553)
Total	$ 19,087,687

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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(4,013,208)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				271,117
3	Preceding Quarter/Year to Date Changes in Fair Value				1,127,170
4	Total (lines 2 and 3)				1,398,287
5	Balance of Account 219 at End of Preceding Quarter/Year				(2,614,921)
6	Balance of Account 219 at Beginning of Current Year				(2,614,921)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				172,419
8	Current Quarter/Year to Date Changes in Fair Value				(703,712)
9	Total (lines 7 and 8)				(531,293)
10	Balance of Account 219 at End of Current Quarter/Year				(3,146,214)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(4,013,208)		
2			271,117		
3			1,127,170		
4			1,398,287	380,309,650	381,707,937
5			(2,614,921)		
6			(2,614,921)		
7			172,419		
8			(703,712)		
9			(531,293)	445,329,227	444,797,934
10			(3,146,214)		

Schedule Page: 122(a)(b) Line No.: 1 Column: e

Lines 1-5 present information for the period 1/1/13 - 12/31/13.

Lines 6-10 present information for the period 1/1/14 - 12/31/14.

Schedule Page: 122(a)(b) Line No.: 1 Column: h

Lines 1-5 present information for the period 1/1/13 - 12/31/13.

Lines 6-10 present information for the period 1/1/14 - 12/31/14.

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses, prior service costs and net transition obligation, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2013.

Schedule Page: 122(a)(b) Line No.: 3 Column: e

Reflects amounts recognized in OCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2013 (as applicable).

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2014.

Schedule Page: 122(a)(b) Line No.: 8 Column: e

Reflects amounts recognized in OCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2014 (as applicable).

Schedule Page: 122(a)(b) Line No.: 10 Column: b

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: c

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: d

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: e

Other Comprehensive Income related to deferred employee benefit plan costs.

Schedule Page: 122(a)(b) Line No.: 10 Column: f

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: g

Not applicable for respondent.

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

The basic financial statements shown on pages 110 through 122 are prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). The significant differences from the GAAP requirements are related to the classification of certain assets and liabilities to include the classification of the current portion of certain regulatory assets, the classification of the current portion of long term debt, the classification of certain deferred income taxes, the classification of certain cost of removal and the classification of plant to be retired. In addition, the accounts of South Carolina Generating Company, Inc. (GENCO) are not consolidated herein, whereas they are so consolidated for GAAP reporting purposes.

These notes are based on the notes contained in South Carolina Electric & Gas Company's (SCE&G) Annual Report on Form 10K filed with the Securities and Exchange Commission and reflect certain reclassifications from the Uniform System of Accounts presentation shown on pages 110 through 122.

Management has evaluated the impact of events occurring after December 31, 2014 up to February 27, 2015, the date that SCE&G's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 17, 2015. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

South Carolina Electric & Gas Company (SCE&G), a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA Corporation (SCANA), a South Carolina corporation. SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in South Carolina Fuel Company, Inc. (Fuel Company), and accordingly, the accompanying consolidated financial statements include the accounts of SCE&G and Fuel Company. The equity interests in Fuel Company are held solely by SCANA, SCE&G's parent.

Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and Allowance for Funds Used During Construction (AFC), are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. SCE&G calculated AFC using average composite rates of 6.5% for 2014, 6.9% for 2013 and 6.3% for 2012. These rates do not exceed the maximum allowable rate as calculated under United States Federal Energy Regulatory Commission (FERC) Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were 2.85% in 2014, 2.96% in 2013 and 2.93% in 2012.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the United States Department of Energy (DOE) under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of V.C Summer Station Unit 1 (Summer Station). In addition, SCE&G will jointly own and will be the operator of the Nuclear Units 2 and 3 being designed and constructed at Summer Station (New Units). Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	**2014**		**2013**	
	Unit 1	**New Units**	**Unit 1**	**New Units**
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.1 billion	—
Accumulated depreciation	$578.3 million	—	$566.9 million	—
Construction work in progress	$199.3 million	$2.7 billion	$127.1 million	$2.3 billion

SCE&G, on behalf of itself and as agent for the South Carolina Public Service Authority (Santee Cooper), has contracted with a consortium consisting of Westinghouse Electric Company LLC and CB&I Stone and Webster, Inc., a subsidiary of Chicago Bridge & Iron Company N.V. (Consortium) for the design and construction of the New Units at the site of Summer Station. For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $88.9 million at December 31, 2014 and $75.6 million at December 31, 2013.

Plant to be Retired

SCE&G expects to retire three units that are or were coal-fired by 2020, subject to future developments in environmental regulations, among other matters. The net carrying value of these units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the Public Service Commission of South Carolina (SCPSC). The net carrying value of three previously retired units is recorded in regulatory assets within unrecovered plant (see Note 2).

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued to regulatory assets in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the balance sheet (see Note 2). Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2014 and 2013, SCE&G incurred $17.3 million and $18.1 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. SCE&G accrued $1.2 million per month from July 2011 through December 2012 for its portion of the outages in the fall of 2012. Total costs for the 2012 outage were $32.3 million, of which SCE&G was responsible for $21.5 million. In connection with the SCPSC's December 2012 approval of SCE&G's retail electric rates (see Note 2), effective January 1, 2013, SCE&G began to accrue $1.4 million per month for its portion of the nuclear refueling outages that are scheduled to occur from the spring of 2014 through the spring of 2020. Total costs for the 2014 outage were $43.7 million, of which SCE&G was responsible for $29.1 million.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2014, 2013 and 2012) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Accounts Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Inventory

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas and fuel oil. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC. Emission allowances are included in inventory at average cost. Emission allowances are expensed at weighted average cost as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

SCE&G is included in the consolidated federal income tax return of SCANA. Under a joint consolidated income tax allocation agreement, each SCANA subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or revenues would be recognized by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

SCE&G records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

SCE&G presents the revenues and expenses of its regulated activities (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $115.8 million at December 31, 2014 and $111.9 million at December 31, 2013.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

Customers subject to the Purchased Gas Adjustment (PGA) are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a Weather Normalization Adjustment (WNA) which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented a pilot electric WNA (eWNA) for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC. See Note 2.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

New Accounting Matters

In April 2014, the Financial Accounting Standards Board (FASB) issued new accounting guidance for reporting discontinued operations and disclosures of disposals of components of an entity. Under this new guidance, only those discontinued operations which represent a strategic shift that will have a major effect on an entity's operations and financial results should be reported as discontinued operations in the financial statements. As permitted, SCE&G adopted this new guidance for the period ended December 31, 2014.

In May 2014, the FASB issued new accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Currently, SCE&G would be required to adopt the new guidance in the first quarter of 2017, and early adoption would not be permitted. However, the FASB may defer the adoption of this guidance for one year. SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

Cost of Removal

In 2013, certain cost of removal related to assets with an associated Asset Retirement Obligation, was reclassified from accumulated provision for depreciation to other regulatory liabilities. Beginning in 2014, all cost of removal components are reflected in accumulated provision for depreciation. See supporting schedules on pages 219 and 278 for roll forward activity.

2. RATE AND OTHER REGULATORY MATTERS

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased. In connection with its annual review of base rates for fuel costs, and by order dated April 30, 2013, the SCPSC approved a settlement agreement among SCE&G, the South Carolina Office of Regulatory Staff (ORS), and the South Carolina Energy Users Committee (SCEUC) in which SCE&G agreed to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. The order also provided for the accrual of certain debt-related carrying costs on a portion of SCE&G's under-collected balance of base fuel costs, and approved SCE&G's total fuel cost component.

Pursuant to a November 2013 SCPSC accounting order, SCE&G's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

By order dated April 29, 2014, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to increase its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs, which was approved by the SCPSC in March 2014. In addition, pursuant to the April 29, 2014 order, SCE&G's electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late

2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs during the period May 1, 2014 through April 30, 2015. See also Note 6.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Policy Act of 1982 (Nuclear Waste Act) for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the United States Court of Appeals for the District of Columbia (Court of Appeals), the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The SCPSC will consider the impact of this action in future cost of fuel rate proceedings.

In October 2014, the SCPSC initiated its 2015 annual review of base rates for fuel costs. In connection with its January 2015 Demand Side Management Programs (DSM Programs) filing (see Electric-Base Rates herein), SCE&G notified the SCPSC that it anticipated proposing an adjustment to its cost of fuel that, if approved, will result in an overall decrease to its base fuel costs beginning with the first billing cycle of May 2015. A public hearing for the annual fuel review was held on April 9, 2015.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term borrowing rate, and $5.8 million and $2.9 million of such carrying costs were accrued within other income during 2014 and 2013, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates, a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. In February 2013, the SCPSC denied the SCEUC's petition for rehearing and the denial was not appealed.

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

SCE&G files an Integrated Resource Plan (IRP) with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, United States Environmental Protection Agency (EPA) regulations, reserve margins and fuel costs. SCE&G previously identified six coal-fired units that it has subsequently retired or intends to retire by 2020, subject to future developments in environmental regulations, among other matters. Three of these units had been retired by December 31, 2013, and their net carrying value is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and net lost revenues associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC approved recovery of the following amounts pursuant to annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million

Other activity related to SCE&G's DSM Programs is as follows:

- In May 2013, the SCPSC ordered the deferral of one-half of the net lost revenues and provided for their recovery over a 12-month period beginning with the first billing cycle in May 2014.

- In April 2014, the SCPSC approved SCE&G's request to (1) recover one-half of the balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2014 and to recover the remaining balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2015, (2) utilize approximately $17.8 million of gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of the net lost revenues component of SCE&G's DSM Program rider, and (3) apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets resulting from the May 2013 order previously described.

- In addition, in April 2014 the SCPSC, upon recommendation of the ORS, reduced by 25%, or $6.6 million, the amount of net lost revenues SCE&G expects to experience over the 12-month period beginning with the first billing cycle of May 2014, and ordered that the $6.6 million be applied to decrease the amount of program costs deferred for recovery. Actual net lost revenues not collected in the current DSM Programs rate rider are subject to true up in the following program year.

- In January 2015, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would, among other things, allow recovery of $33.0 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

<u>Electric – Base Load Review Act (BLRA)</u>

In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the Combined Construction and Operating License (COL) and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. In December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million
2012	2.3%	$52.1 million

Gas

The Natural Gas Rate Stabilization Act (RSA) is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2014	0.6% Decrease	$ 2.6 million
2013	No change	
2012	2.1% Increase	$ 7.5 million

SCE&G's natural gas tariffs include a Purchased Gas Adjustment (PGA) that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2014 and 2013 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each review period were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2014**	**2013**
Regulatory Assets:		
Accumulated deferred income taxes	$ 261	$ 239
Under-collections-electric fuel adjustment clause	20	18
Environmental remediation costs	36	37
AROs and related funding	333	337
Franchise agreements	26	31
Deferred employee benefit plan costs	309	214
Planned major maintenance	2	—
Deferred losses on interest rate derivatives	445	124
Deferred pollution control costs	36	37
Unrecovered plant	137	145
DSM Programs	56	51
Other	44	39
Total Regulatory Assets	$ 1,705	$ 1,272
Regulatory Liabilities:		
Accumulated deferred income taxes	$ 15	$ 17
Asset removal costs	476	463
Storm damage reserve	6	27
Deferred gains on interest rate derivatives	82	181
Planned major maintenance	—	10
Total Regulatory Liabilities	$ 579	$ 698

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recovered over periods of up to approximately 25 years.

Asset Retirement Obligation (ARO) and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on an SCPSC order, SCE&G is recovering these amounts through cost of service rates through 2020.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil-fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects and accrues $18.4 million annually for fossil-fueled turbine/generation equipment maintenance, and collects and accrues $17.2 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2038. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense over periods up to approximately 50 years except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC. Also, in 2014, as discussed above at Rate Matters - Electric - Cost of Fuel and Rate Matters - Electric - Base Rates, certain of these deferred amounts were applied to offset under-collected fuel balances and unrecorded net lost revenues related to DSM Programs.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at certain coal-fired generating plants pursuant to specific regulatory orders. Such costs are being recovered through utility rates through 2045.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2014 SCPSC order, deferred costs are currently being recovered over approximately ten years through an approved rate rider. See Rate Matters - Electric - Base Rates above for details regarding the 2014 filing with the SCPSC regarding recovery of these deferred costs.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the non-legal obligation to remove assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely. In 2014, $16.8 million of the reserve was applied to offset incremental storm damage costs. Also, as discussed above at Rate Matters - Electric - Base Rates, in April 2014 $5.0 million of the reserve was applied to offset unrecovered net lost revenues related to DSM Programs.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2014 and 2013. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2014 and 2013.

SCE&G’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2014 and 2013, retained earnings of approximately $67.7 million and $63.1 million, respectively, were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2014		2013	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
First Mortgage Bonds (secured)	2018 - 2064	$ 3,840	5.56%	$ 3,540	5.60%
Industrial and Pollution Control Bonds (a)	2028 - 2038	89	3.42%	89	3.42%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other	2015 - 2027	14	2.63%	15	2.26%
Total debt		4,043		3,744	
Current maturities of long-term debt		(3)		(5)	
Unamortized premium		5		8	
Total long-term debt, net		$ 4,045		$ 3,747	

(a) Includes variable rate debt of $34.6 million at December 31, 2014 (rate of 0.04%) and 2013 (rate of 0.11%), which are hedged by fixed swaps.

The annual amounts of long-term debt maturities for the next five years are summarized as follows:

Year	**Millions of dollars**
2015	$ 3
2016	103
2017	2
2018	552
2019	1

Substantially all of SCE&G’s electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2014, the Bond Ratio was 5.41.

Lines of Credit and Short-Term Borrowings

At December 31, 2014 and 2013, SCE&G (including Fuel Company) had available the following committed Lines of Credit (LOC) and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	**2014**	**2013**
Lines of credit:		
Total committed long-term	$ 1,400	$ 1,400
Outstanding commercial paper (270 or fewer days)	$ 709	$ 251
Weighted average interest rate	0.52%	0.27%
Letters of credit supported by an LOC	$ 0.3	$ 0.3
Available	$ 691	$ 1,149

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company). In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In October 2014, the term of the five-year agreements was extended by one year, such that they expire in October 2019. The three-year agreement expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N. A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1.4 billion credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9% and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

SCE&G is obligated with respect to an aggregate of $34.6 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2014 SCE&G had outstanding money pool borrowings due to an affiliate of $17 million and money pool investments due from an affiliate of $80 million. At December 31, 2013 SCE&G had no outstanding money pool borrowings due to an affiliate. On the consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	2014	2013	2012
Current taxes:			
Federal	$ 39	$ 145	$ 88
State	(7)	15	11
Total current taxes	32	160	99
Deferred taxes, net:			
Federal	151	20	60
State	32	6	8
Total deferred taxes	183	26	68
Investment tax credits:			
Amortization of amounts deferred—state	(1)	(1)	(14)
Amortization of amounts deferred—federal	(3)	(2)	(2)
Total investment tax credits	(4)	(3)	(16)
Total income tax expense	$ 211	$ 183	$ 151

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2014	2013	2012
Net income	$ 446	$ 380	$ 341
Income tax expense	211	183	151
Total pre-tax income	$ 657	$ 563	$ 492
Income taxes on above at statutory federal income tax rate	$ 230	$ 197	$ 172
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	20	17	16
State investment tax credits (less federal income tax effect)	(5)	(5)	(13)
Allowance for equity funds used during construction	(10)	(9)	(7)
Amortization of federal investment tax credits	(2)	(2)	(2)
Section 41 tax credits	(3)	—	—
Section 45 tax credits	(9)	(5)	(5)
Domestic production activities deduction	(7)	(11)	(9)
Other differences, net	(3)	1	(1)
Total income tax expense	$ 211	$ 183	$ 151

The tax effects of significant temporary differences comprising SCE&G's net deferred tax liability are as follows:

Millions of dollars	2014	2013
Deferred tax assets:		
Nondeductible accruals	$ 46	$ 16
Asset retirement obligation-,including nuclear decommissioning	199	204
Unamortized investment tax credits	16	18
Regulatory liability, net gain on interest rate derivative contracts settlement	—	27
Other	7	11
Total deferred tax assets	268	276
Deferred tax liabilities:		
Property, plant and equipment	$ 1,529	$ 1,406
Regulatory asset - asset retirement obligation	109	109
Deferred employee benefit plan costs	90	54
Deferred fuel costs	28	26
Regulatory asset- unrecovered plant	52	55
Regulatory asset- net loss on interest rate derivative contracts settlement	21	—
Demand side management costs	21	21
Prepayments	25	23
Other	24	17
Total deferred tax liabilities	1,899	1,711
Net deferred tax liability	$ 1,631	$ 1,435

SCE&G is included in the consolidated federal income tax return of SCANA and files various applicable state and local income tax returns. The United States Internal Revenue Service (IRS) has completed examinations of SCANA's federal returns through 2004, and SCANA's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2012. With few exceptions, SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	2014	2013	2012
Unrecognized tax benefits, January 1	$ 3	—	$ 35
Gross increases-uncertain tax positions in prior period	—	—	—
Gross decreases-uncertain tax positions in prior period	—	—	(35)
Gross increases-current period uncertain tax positions	13	$ 3	—
Settlements	—	—	—
Lapse of statute of limitations	—	—	—
Unrecognized tax benefits, December 31	$16	$ 3	$ —

In connection with the change in method of tax accounting for certain repair costs in prior years, the Company had previously recorded an unrecognized tax benefit. During the first quarter of 2012, the publication of new administrative guidance from the IRS allowed SCE&G to recognize this benefit. Since this change was primarily a temporary difference, the recognition of this benefit did not have a significant effect on the SCE&G's effective tax rate.

During 2013 and 2014, SCE&G amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, SCE&G recorded an unrecognized tax benefit of $16 million. If recognized, $13 million of the tax benefit would affect SCE&G's effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $2 million within the next 12 months. It is also reasonably possible that this tax benefit may decrease by $7 million within the next 12 months. No other material changes in the status of the SCE&G's tax positions have occurred through December 31, 2014.

As of December 31, 2014, accounts receivable related to taxes are primarily due to the late 2014 extension of the 50% bonus depreciation deduction.

SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit in 2012, during 2012 SCE&G reversed $2 million of interest expense which had been accrued during 2011. SCE&G has not recorded interest expense or penalties associated with uncertain tax positions in 2013 or 2014.

6. DERIVATIVE FINANCIAL INSTRUMENTS

SCE&G recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by SCE&G. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including SCE&G. The Risk Management Committee, which is comprised of certain officers, including SCE&G's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, SCE&G may use treasury rate lock or forward starting swap agreements. Pursuant to regulatory orders issued in 2013, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders issued in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel balances in April 2014. The

SCPSC also approved SCE&G's request to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G's DSM Program rider and apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.1 billion and $1.3 billion at December 31, 2014 and 2013, respectively.

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments	**Asset Derivatives**		**Liability Derivatives**	
Millions of dollars	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
As of December 31, 2014				
Not designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$ 207
			Other deferred credits and other liabilities	17
Total				$ 224
As of December 31, 2013				
Not designated as hedging instruments				
Interest rate contracts	Other current assets	$ 13	Derivative financial instruments	$ —
	Other deferred debits and other assets	19		
Total		$ 32		$ —

The effect of derivative instruments on the consolidated statements of income is as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Deferred in Regulatory Accounts (Effective Portion)**	**Gain (Loss) Reclassified from Deferred Accounts into Income (Effective Portion)**	
Millions of dollars		**Location**	**Amount**
Year Ended December 31, 2014			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2013			
Interest rate contracts	$ 100	Interest expense	$ (2)
Year Ended December 31, 2012			
Interest rate contracts	$ 85	Interest expense	$ (2)

As of December 31, 2014, SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.2 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gains (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments	**Loss Recognized in Income**	**Year Ended December 31,**		
Millions of dollars	**Location**	**2014**	**2013**	**2012**
Commodity contracts	Gas purchased for resale	—	—	$ (1)

	Gain or (Loss) Deferred in Regulatory Accounts	**Gain Reclassified from Deferred Accounts into Income**	
Millions of dollars		**Location**	**Amount**
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64
Year Ended December 31, 2013			
Interest rate contracts	$ 39	Other income	$ 50
Year Ended December 31, 2012			
Interest rate contracts	—	Other income	—

The gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2014, SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $5.2 million as an increase to other income.

Credit Risk Considerations

SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. SCE&G uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of SCE&G's derivative instruments contain contingent provisions that require SCE&G to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2014 and 2013, SCE&G had posted $107.1 million and $-, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Other Current Assets on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2014 and 2013, SCE&G would have been required to post an additional $125.9 million and $- million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2014 and 2013, are $233.0 million and $-, respectively.

In addition, as of December 31, 2014 and December 31, 2013, SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2014 and December 31, 2013, SCE&G could request $- million and $31.7 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2014 and December 31, 2013 is $- million and $31.7 million, respectively.

Information related to SCE&G's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2014						
Interest rate	—	—	—	—	—	—
As of December 31, 2013						
Interest rate	$ 32	—	$ 32	$ (1)	—	$ 31
Balance sheet location	Other current assets		$ 13			
	Other deferred debits and other assets		19			
	Total		$ 32			

Offsetting Derivative Liabilities

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2014						
Interest rate	$ 224	—	$ 224	—	$ (98)	$ 126
Balance sheet location	Derivative financial instruments		$ 207			
	Other deferred credits and other liabilities		17			
	Total		$ 224			
As of December 31, 2013						
Interest rate	$ 1	—	$ 1	$ (1)	—	—
Balance sheet location	Derivative financial instruments		$ 1			
	Total		$ 1			

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value Level 2 measurements were as follows:

Millions of dollars	As of December 31, 2014 Level 2	As of December 31, 2013 Level 2
Assets-Interest rate contracts	—	$ 32
Liabilities-Interest rate contracts	$ 224	—

There were no Level 1 or Level 3 fair value measurements for either period presented and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2014 and December 31, 2013 were as follows:

	As of December 31, 2014		As of December 31, 2013	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$ 4,048.6	$ 4,776.6	$ 3,752.3	$ 4,088.0

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees hired before January 1, 2014. Benefits are no longer offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost. Employees hired after December 31, 2010 are responsible for the full costs of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumptions based on SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		**Other Postretirement Benefits**	
Millions of dollars	**2014**	**2013**	**2014**	**2013**
Benefit obligation, January 1	$ 695.7	$ 788.4	$ 181.2	$ 204.8
Service cost	16.0	17.6	3.6	4.5
Interest cost	34.1	32.6	9.2	8.5
Plan participants' contributions	—	—	1.7	2.0
Actuarial (gain) loss	82.7	(70.7)	18.2	(26.8)
Benefits paid	(54.8)	(50.6)	(9.4)	(9.1)
Curtailment	—	(21.6)	—	—
Amounts funded to parent	—	—	(1.3)	(2.7)
Benefit obligation, December 31	$ 773.7	$ 695.7	$ 203.2	$ 181.2

The accumulated benefit obligation for pension benefits was $747.6 million at the end of 2014 and $673.2 million at the end of 2013. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		**Other Postretirement Benefits**	
	2014	**2013**	**2014**	**2013**
Annual discount rate used to determine benefit obligation	4.20%	5.03%	4.30%	5.19%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.75%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.9

million at December 31, 2014 and by $1.0 million at December 31, 2013. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.8 million at December 31, 2014 and by $0.9 million at December 31, 2013.

Funded Status

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2014**	**2013**	**2014**	**2013**
Fair value of plan assets	$ 783.6	$ 792.1	—	—
Benefit obligation	773.7	695.7	$ 203.2	$ 181.2
Funded status	$ 9.9	$ 96.4	$ (203.2)	$ (181.2)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2014**	**2013**	**2014**	**2013**
Current liability	—	—	$ (8.5)	$ (7.8)
Noncurrent asset	$ 9.9	$ 96.4	—	—
Noncurrent liability	—	—	(195.7)	(173.4)

Amounts recognized in accumulated other comprehensive loss (a component of common equity) as of December 31, 2014 and 2013 were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2014**	**2013**	**2014**	**2013**
Net actuarial loss	$ 1.9	$ 1.8	$ 1.0	$ 0.6
Prior service cost	0.1	0.2	—	—
Total	$ 2.0	$ 2.0	$ 1.0	$ 0.6

Amounts recognized in regulatory assets as of December 31, 2014 and 2013 were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2014**	**2013**	**2014**	**2013**
Net actuarial loss	$ 191.9	$ 107.7	$ 35.0	$ 19.5
Prior service cost	8.3	11.1	0.5	0.7
Total	$ 200.2	$ 118.8	$ 35.5	$ 20.2

In connection with the joint ownership of Summer Station, as of December 31, 2014 and 2013, SCE&G recorded within deferred debits $17.8 million and $14.1 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2014 and 2013, SCE&G also recorded within deferred debits $15.1 million and $12.6 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

Millions of dollars	Pension Benefits 2014	2013
Fair value of plan assets, January 1	$792.1	$ 732.0
Actual return on plan assets	46.3	110.7
Benefits paid	(54.8)	(50.6)
Fair value of plan assets, December 31	$783.6	$ 792.1

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan is closed to new entrants effective January 1, 2014, and benefit accruals will cease effective January 1, 2024. In addition, during 2013, SCANA adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs in connection with the amendments to the plan.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2014 and 2013 and the target allocation for 2015 are as follows:

	Percentage of Plan Assets		
	Target Allocation	At December 31,	
Asset Category	2015	2014	2013
Equity Securities	58%	57%	59%
Fixed Income	33%	34%	32%
Hedge Funds	9%	9%	9%

For 2015, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes an asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy adopted for 2013.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2014 and 2013, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using						
Millions of dollars	**Total**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**
	December 31, 2014			*December 31, 2013*			
Common stock	—	—	—	$302	$302	—	—
Preferred stock	—	—	—	1	1	—	—
Mutual funds	$566	$566	—	278	18	$260	—
Short-term investment vehicles	18	18	—	18	—	18	—
US Treasury securities	6	6	—	30	—	30	—
Corporate debt securities	78	78	—	48	—	48	—
Loans secured by mortgages	—	—	—	11	—	11	—
Municipals	14	14	—	3	—	3	—
Limited partnerships	29	29	—	32	1	31	—
Multi-strategy hedge funds	73	—	$73	69	—	—	$69
	$784	$711	$73	$ 792	$322	$401	$69

At December 31, 2014, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2014 or 2013.

The pension plan values common stock, preferred stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as The New York Stock Exchange and The NASDAQ Stock Market, Inc., where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

Millions of dollars	Fair Value Measurements Level 3	
	2014	2013
Beginning Balance	$ 69	$ 64
Unrealized gains included in changes in net assets	4	5
Purchases, issuances, and settlements	—	—
Ending Balance	$ 73	$ 69

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from SCE&G's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2015	$ 63.4	$ 8.9
2016	64.5	9.6
2017	65.6	10.2
2018	66.1	10.7
2019	65.1	11.3
2020 - 2024	338.4	63.3

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Service cost	$ 16.0	$ 17.6	$ 15.7	$ 3.6	$ 4.5	$ 3.7
Interest cost	34.1	32.6	36.4	9.2	8.5	9.1
Expected return on assets	(56.3)	(51.9)	(50.4)	n/a	n/a	n/a
Prior service cost amortization	3.5	5.0	6.0	0.3	0.6	0.7
Amortization of actuarial losses	4.0	14.3	15.6	—	2.6	1.1
Transition obligation amortization	—	—	—	—	—	(0.1)
Curtailment	—	8.4	—	—	—	—
Net periodic benefit cost	$ 1.3	$ 26.0	$ 23.3	$ 13.1	$ 16.2	$ 14.5

In connection with regulatory orders, in 2013 SCE&G began recovering current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). SCE&G is amortizing previously deferred pension costs as further described in Note 2.

Other changes in plan assets and benefit obligations recognized in other comprehensive income (OCI), net of tax, were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Current year actuarial (gain) loss	$ 0.2	$ (0.8)	$ 0.4	$ 0.4	$ (0.4)	$ 0.7
Amortization of actuarial losses	(0.1)	(0.1)	(0.1)	—	(0.1)	—
Amortization of prior service cost	(0.1)	—	(0.1)	—	—	(0.1)
Total recognized in OCI	$ —	$ (0.9)	$ 0.2	$ 0.4	$ (0.5)	$ 0.6

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Current year actuarial (gain) loss	$ 87.7	$ (137.1)	$ 37.9	$ 15.5	$ (23.9)	$ 25.1
Amortization of actuarial losses	(3.5)	(12.7)	(14.0)	—	(2.2)	(1.0)
Amortization of prior service cost	(2.8)	(4.5)	(5.7)	(0.2)	(0.5)	(0.6)
Prior service cost (credit)	—	(7.7)	—	—	—	—
Amortization of transition obligation	—	—	—	—	(0.1)	(0.2)
Total recognized in regulatory assets	$ 81.4	$ (162.0)	$ 18.2	$ 15.3	$ (26.7)	$ 23.3

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
Discount rate	5.03%	4.10%/5.07%	5.25%	5.19%	4.19%	5.35%
Expected return on plan assets	8.00%	8.00%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.75%/3.00%	4.00%	3.75%	3.75%	4.00%
Health care cost trend rate	n/a	n/a	n/a	7.40%	7.80%	8.20%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2015 are as follows:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 10.6	$ 1.5
Prior service cost	3.1	0.2
Total	$ 13.7	$ 1.7

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

Stock Purchase Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee’s eligible earnings. Total matching contributions made to the plan were $20.7 million in 2014, $18.7 million in 2013 and $17.7 million in 2012 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the SCANA Long-Term Equity Compensation Plan (LTECP) which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA’s common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

Liability Awards

The 2012-2014, 2013-2015, and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. In each performance cycle, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to exceptions for retirement, death, disability or change in control. The remaining 80% of the award was granted in performance shares, which are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to exceptions for retirement, death or disability. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of total shareholder return as compared to a peer group of utilities (weighted 50%) and growth in "GAAP-adjusted net earnings per share from operations" (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2012-2014 performance cycle were paid in cash at SCANA's discretion in February 2015. Cash-settled liabilities related to the performance cycles were paid totaling approximately $1.9 million in 2014, $3.2 million in 2013 and $8.7 million in 2012.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling approximately $12.6 million in 2014, $5.5 million in 2013 and $9.5 million in 2012. Fair value adjustments resulted in capitalized compensation costs of $0.6 million in 2014, $0.5 million in 2013 and $2.1 million in 2012.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under the Price-Anderson Indemnification Act (Price-Anderson), SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the United States Nuclear Regulatory Commission (NRC) that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with Nuclear Electric Insurance Limited (NEIL). The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station.

SCE&G's current ownership share in the New Units is 55%. As discussed below, under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2014, SCE&G's investment in the New Units totaled $2.7 billion, for which the financing costs on $2.425 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule, including 146 milestones within that schedule, and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC also approved an 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain focus areas of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01, as well as shield building modules, are considered critical path items for both New Units. CA20 was placed on the nuclear island of Unit 2 in May 2014. The delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of Unit 2 during the first half of 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The intended result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014, SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 was expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

During the third quarter of 2014, the Consortium also provided preliminary cost estimates for Units 2 and 3, principally related to delays for non-firm and non-fixed scopes of work to achieve a late 2018 substantial completion date for Unit 2 and a substantial completion date for Unit 3 approximately 12 months later. SCE&G's 55% portion of this preliminary estimate is approximately $660 million, excluding any owner's cost amounts associated with the delays, which could be $10 million per month for delays beyond the current SCPSC-approved substantial completion dates. This figure is presented in 2007 dollars and would be subject to escalation, which could be material. Further, this figure does not reflect consideration of the liquidated damages provisions of the Engineering, Procurement and Construction Agreement dated May 23, 2008 (EPC Contract) which would partly mitigate any such delay-related costs. The Consortium's preliminary schedule and the cost estimate information have not been accepted by SCE&G and are under review, and SCE&G cannot predict when a revised schedule and cost estimate will be resolved with the Consortium.

Since receiving the August 2014 preliminary information, SCE&G has worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium now indicates that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. SCE&G is continuing discussions with Consortium executive management in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of December 31, 2014, 101 milestones have been completed. Three of the remaining milestones have not been or will not be completed within their 18-month contingency periods, and it is anticipated that the completion dates for a number of the other remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are now projected to exceed amounts currently approved by the SCPSC of $4.548 billion and $5.755 billion, respectively. As such, on March 12, 2015 SCE&G, as provided for under the BLRA, petitioned the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. In addition, that petition included certain updated owner's costs and other capital costs, including amounts within the Consortium's preliminary cost estimate which may be the subject of dispute. As such, the petition did not reflect the resolution of the above described negotiations. The petition included incremental capital costs that total $698 million (SCE&G's portion in 2007 dollars). The total project capital cost is now estimated at approximately $5.2 billion (SCE&G's portion in 2007 dollars) or $6.8 billion including escalation and allowance for funds used during construction (SCE&G's portion in future dollars). The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G. A hearing before the SCPSC has been scheduled for July 21, 2015 with an order due by September 12, 2015.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes (including any ultimate disagreements involving the preliminary cost estimates provided by the Consortium in the third quarter of 2014) through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the current milestone schedule and capital costs schedule approved by the SCPSC in November 2012, SCE&G's estimated cost would be approximately $500 million for the additional 5% interest being acquired from Santee Cooper. This cost figure could be higher in light of the delays and related costs discussed above.

Nuclear Production Tax Credits

In August 2014, the IRS notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. SCE&G fulfilled the request related to emergency plant staffing in 2012. In addition, SCE&G prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the Clean Air Act, as amended (CAA), Clean Water Act (CWA), Nuclear Waste Act and the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), among others. In many cases, regulations proposed by such authorities could have a significant impact on SCE&G's financial condition, results of operations and cash flows. In addition, SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

The EPA issued a revised carbon standard for new power plants by re-proposing New Source Performance Standards under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The proposed rule was issued on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. SCE&G is evaluating the proposed rule, but does not plan to construct new coal-fired units in the near future. In addition, on June 2, 2014, the EPA issued proposed emission guidelines for states to follow in developing plans to address greenhouse gas (GHG) emissions from existing units. These guidelines are to be made final no later than June 1, 2015, and include state-specific rate based goals for carbon dioxide emissions.

From a regulatory perspective, SCE&G continually monitors and evaluates its current and projected emission levels and strives to comply with all state and federal regulations regarding those emissions. SCE&G participates in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also has constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In July 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, thus delaying the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the Clean Air Interstate Rule and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle National Ambient Air Quality Standard. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. Air quality control installations that SCE&G have already completed have positioned them to comply with the allowances set by the CSAPR.

In April 2012, the EPA's Mercury and Air Toxics Standards (MATS) rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and SCE&G's evaluation of the rule is ongoing. SCE&G's decision to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in SCE&G's compliance with MATS. On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities. SCE&G has received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin and Wateree Stations. South Carolina Generationg Company, Inc. (GENCO) has also received a one year extension at its Williams Station, which is operated by SCE&G. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The New federal effluent limitation guidelines for steam electric generating units was published in the Federal Register on June 7, 2013, and is expected to be finalized no later than September 30, 2015. Once the rule becomes effective, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. Based on the proposed rule, SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities.

The CWA Section 316(b) Existing Facilities Rule became effective on October 14, 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G is conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On December 19, 2014, the EPA issued a final rule for Coal Combustion Residuals (CCR), which is expected to become effective in 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act. In addition, this rule imposes certain requirements on ash storage ponds at SCE&G's generating facilities. SCE&G has already closed or has begun the process of closure of all of their ash storage ponds.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2014, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and is constructing a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned manufactured gas plant (MGP) sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by the South Carolina Department of Health and Environmental Control and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2017 and will cost an additional $19.3 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2014, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $35.5 million and are included in regulatory assets.

Claims and Litigation

SCE&G is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on SCE&G’s results of operations, cash flows or financial condition.

Operating Lease Commitments

SCE&G is obligated under various operating leases for vehicles, office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $12.0 million in 2014, $13.6 million in 2013 and $9.6 million in 2012. Future minimum rental payments under such leases are as follows:

	Millions of dollars
2015	$ 6
2016	3
2017	1
2018	—
2019	1
Thereafter	18
Total	$ 29

Asset Retirement Obligations

SCE&G recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to SCE&G’s regulated utility operations. As of December 31, 2014, SCE&G has recorded AROs of approximately $201 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $320 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars	2014	2013
Beginning balance	$ 532	$ 516
Liabilities incurred	3	6
Liabilities settled	(6)	(4)
Accretion expense	24	23
Revisions in estimated cash flows	(32)	(9)
Ending Balance	$ 521	$ 532

Revisions in estimated cash flows for 2014 primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

Carolina Gas Transmission Corporation (CGT) transports natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. Such purchases totaled approximately $30.0 million in 2014, $33.3 million in 2013 and $35.9 million in 2012. SCE&G had approximately $3.3 million payable to CGT for transportation services at both December 31, 2014 and December 31, 2013. SCE&G had approximately $1.2 million and $1.3 million receivable from CGT for transportation services at December 31, 2014 and December 31, 2013, respectively.

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy Marketing, Inc. (SEMI) to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $195.7 million in 2014, $166.9 million in 2013 and $125.5 million in 2012. SCE&G's payables to SEMI for such purposes were $12.6 million and $12.5 million as of December 31, 2014 and 2013, respectively.

SCE&G purchases all of the electric generation of Williams Station under a unit power sales agreement. Such unit power purchases, which are included in "Purchased power," totaled approximately $231.5 million and $227.0 million in 2014 and 2013, respectively. SCE&G had approximately $21.4 million and $23.2 million, payable to GENCO for unit power purchases at December 31, 2014 and 2013, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC which is involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's receivable from this affiliate was $13.8 million at December 31, 2014 and $2.5 million at December 31, 2013. SCE&G's payable to this affiliate was $13.9 million at December 31, 2014 and $2.5 million at December 31, 2013. SCE&G's total purchases from this affiliate were $120.4 million in 2014 and $71.8 million in 2013. SCE&G's total sales to this affiliate were $119.8 million in 2014 and $71.5 million in 2013.

SCANA Services provides the following services to SCE&G, which are rendered at direct or allocated cost: information systems services, telecommunications services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, general administrative services and retirement benefits. In addition, SCANA Services processes and pays invoices for SCE&G and is reimbursed. Costs for these services totaled $294.9 million in 2014, $276.0 million in 2013 and $296.6 million in 2012. SCE&G's payables to SCANA Services for these services were $46.4 million and $48.2 million at December 31, 2014 and 2013, respectively.

Borrowings from and investments in an affiliated money pool are described in Note 4.

12. SEGMENT OF BUSINESS INFORMATION

SCE&G’s reportable segments follow the same accounting policies as those described in Note 1.

Electric Operations primarily generates, transmits, and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution purchases and sells natural gas, primarily at retail, and is regulated by the SCPSC.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	730	62	—	792
Interest Expense	1	—	$ 209	210
Depreciation and Amortization	281	27	—	308
Segment Assets	9,547	721	3,231	13,499
Expenditures for Assets	925	55	(57)	923
Deferred Tax Assets	4	n/a	(4)	—
2013				
External Revenue	$ 2,431	$ 414	—	$ 2,845
Operating Income	644	58	—	702
Interest Expense	2	—	$ 198	200
Depreciation and Amortization	276	26	—	302
Segment Assets	8,864	686	2,556	12,106
Expenditures for Assets	900	45	51	996
Deferred Tax Assets	9	n/a	(9)	—
2012				
External Revenue	$ 2,453	$ 356	—	$ 2,809
Operating Income	632	49	—	681
Interest Expense	2	—	$ 190	192
Depreciation and Amortization	259	25	—	284
Segment Assets	8,339	659	2,491	11,489
Expenditures for Assets	993	56	(77)	972
Deferred Tax Assets	(1)	n/a	1	—

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, SCE&G does not allocate interest charges, income tax expense, earnings available to common shareholder or assets other than utility plant to its segments. Intersegment revenue and interest income were not significant. SCE&G's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to asset retirement obligations, and totals not allocated to other segments.

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $192 million and $183 million in 2014 and 2013, respectively (net of capitalized interest of $14 million and $13 million in 2014 and 2013, respectively).

Cash paid for income taxes: $174 million and $93 million in 2014 and 2013, respectively.

Noncash Investing and Financing Activities:
Accrued construction expenditures: $151 million and $99 million in 2014 and 2013, respectively.
Capital leases expenditures: $5 million and $4 million in 2014 and 2013, respectively.
Nuclear fuel purchase: $- and $98 million in 2014 and 2013, respectively.

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2014					
Total operating revenues	$ 859	$ 698	$ 812	$ 722	$ 3,091
Operating income	230	135	263	164	792
Earnings Available to Common Shareholder	123	96	154	72	445
2013					
Total operating revenues	$ 728	$ 696	$ 776	$ 645	$ 2,845
Operating income	182	171	246	103	702
Earnings Available to Common Shareholder	89	85	137	69	380

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	9,941,914,037	8,674,582,046
4	Property Under Capital Leases	11,981,350	10,772,663
5	Plant Purchased or Sold		
6	Completed Construction not Classified	255,213,133	212,738,545
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,209,108,520	8,898,093,254
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	3,295,945,264	3,264,008,059
12	Acquisition Adjustments	31,597,076	31,360,826
13	Total Utility Plant (8 thru 12)	13,536,650,860	12,193,462,139
14	Accum Prov for Depr, Amort, & Depl	4,061,048,465	3,518,157,722
15	Net Utility Plant (13 less 14)	9,475,602,395	8,675,304,417
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,867,748,656	3,449,297,294
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	188,478,495	64,140,660
22	Total In Service (18 thru 21)	4,056,227,151	3,513,437,954
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	4,821,314	4,719,768
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,061,048,465	3,518,157,722

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
940,111,511				327,220,480	3
247,673				961,014	4
					5
38,369,540				4,105,048	6
					7
978,728,724				332,286,542	8
					9
					10
12,415,322				19,521,883	11
236,250					12
991,380,296				351,808,425	13
380,017,134				162,873,609	14
611,363,162				188,934,816	15
					16
					17
370,531,402				47,919,960	18
					19
					20
9,384,186				114,953,649	21
379,915,588				162,873,609	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
101,546					32
380,017,134				162,873,609	33

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	5,753,150	2,937,275
3	Nuclear Materials	130,048,797	60,565,844
4	Allowance for Funds Used during Construction	831,716	618,584
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	136,633,663	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	115,386,817	68,804,864
9	In Reactor (120.3)	219,655,819	68,034,005
10	SUBTOTAL (Total 8 & 9)	335,042,636	
11	Spent Nuclear Fuel (120.4)	533,846,170	64,815,551
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	695,877,789	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	309,644,680	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	6,765,799	1,924,626	2
	61,129,110	129,485,531	3
	139,096	1,311,204	4
			5
		132,721,361	6
			7
	68,034,005	116,157,676	8
	64,815,551	222,874,273	9
		339,031,949	10
		598,661,721	11
			12
-45,229,090		741,106,879	13
		329,308,152	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 2 Column: e

Total fabrication transferred from Batch 24 In-process to Batch 24 Stock.

Schedule Page: 202 Line No.: 3 Column: e

Total nuclear materials transferred from Batch 24 In-process to Batch 24 Stock.

Schedule Page: 202 Line No.: 4 Column: e

Total Allowance for Funds Used During Construction transferred from Batch 24 In-process to Batch 24 Stock.

Schedule Page: 202 Line No.: 8 Column: e

Total amount transferred from Batch 24 Stock to Batch 24 In-reactor.

Schedule Page: 202 Line No.: 9 Column: e

Amount transferred from Batch 21 In-reactor to Batch 21 Spent Fuel.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	14,989	
3	(302) Franchises and Consents	13,208,505	
4	(303) Miscellaneous Intangible Plant	58,635,249	6,884,498
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	71,858,743	6,884,498
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,550,196	11,103
9	(311) Structures and Improvements	183,746,082	64,253,120
10	(312) Boiler Plant Equipment	1,109,421,889	-46,713,035
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	420,846,041	3,180,346
13	(315) Accessory Electric Equipment	63,816,140	15,510,010
14	(316) Misc. Power Plant Equipment	27,596,872	1,161,922
15	(317) Asset Retirement Costs for Steam Production	66,944,063	-29,218,879
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,885,921,283	8,184,587
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	896,820	-231
19	(321) Structures and Improvements	275,144,410	6,516,325
20	(322) Reactor Plant Equipment	468,674,814	11,553,370
21	(323) Turbogenerator Units	97,184,258	775,379
22	(324) Accessory Electric Equipment	101,551,971	136,570
23	(325) Misc. Power Plant Equipment	108,018,983	-382,493
24	(326) Asset Retirement Costs for Nuclear Production	43,803,621	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,095,274,877	18,598,920
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	29,509,720	20,529
28	(331) Structures and Improvements	49,242,079	193,979
29	(332) Reservoirs, Dams, and Waterways	444,888,034	295,958
30	(333) Water Wheels, Turbines, and Generators	83,493,413	2,089,686
31	(334) Accessory Electric Equipment	16,506,854	5,070,117
32	(335) Misc. Power PLant Equipment	9,524,039	128,757
33	(336) Roads, Railroads, and Bridges	1,817,517	
34	(337) Asset Retirement Costs for Hydraulic Production	-14,965	-3,549
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	634,966,691	7,795,477
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,206,302	
38	(341) Structures and Improvements	40,915,540	81,487
39	(342) Fuel Holders, Products, and Accessories	8,341,891	5,805
40	(343) Prime Movers	583,705,983	5,747,031
41	(344) Generators	93,629,647	13,734
42	(345) Accessory Electric Equipment	56,347,464	414,714
43	(346) Misc. Power Plant Equipment	1,661,360	26,593
44	(347) Asset Retirement Costs for Other Production	10,308,965	-877,968
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	798,117,152	5,411,396
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,414,280,003	39,990,380

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			14,989		2
			13,208,505		3
390,991		-419,668	64,709,088		4
390,991		-419,668	77,932,582		5
					6
					7
			13,561,299		8
161,402			247,837,800		9
10,563,879		-66,295	1,052,078,680		10
					11
1,715,930		-113,707	422,196,750		12
202,505			79,123,645		13
430,874		-17,506	28,310,414		14
-13,416,601			51,141,785		15
-342,011		-197,508	1,894,250,373		16
					17
15,977			880,612		18
3,848,796			277,811,939		19
4,978,644			475,249,540		20
100,582			97,859,055		21
49,720		-138,248	101,500,573		22
1,660,871			105,975,619		23
			43,803,621		24
10,654,590		-138,248	1,103,080,959		25
					26
87,592		-7	29,442,650		27
40,186			49,395,872		28
1,762,004			443,421,988		29
46,562			85,536,537		30
945,560			20,631,411		31
19,712		9,038	9,642,122		32
			1,817,517		33
			-18,514		34
2,901,616		9,031	639,869,583		35
					36
288,316			2,917,986		37
78,616			40,918,411		38
63,288		-115,841	8,168,567		39
2,275,116		180,002	587,357,900		40
1,068,872			92,574,509		41
108,103		-4,649,106	52,004,969		42
			1,687,953		43
-52,632			9,483,629		44
3,829,679		-4,584,945	795,113,924		45
17,043,874		-4,911,670	4,432,314,839		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	62,848,022	15,860,265
49	(352) Structures and Improvements	4,743,335	
50	(353) Station Equipment	414,024,576	17,594,698
51	(354) Towers and Fixtures	5,415,626	
52	(355) Poles and Fixtures	292,248,666	31,346,065
53	(356) Overhead Conductors and Devices	176,392,693	13,759,670
54	(357) Underground Conduit	15,642,322	5,082,602
55	(358) Underground Conductors and Devices	29,268,309	26,240,127
56	(359) Roads and Trails	74,386	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,000,657,935	109,883,427
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	52,511,639	565,720
61	(361) Structures and Improvements	4,914,067	3,742
62	(362) Station Equipment	353,246,423	14,143,970
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	400,285,906	24,554,429
65	(365) Overhead Conductors and Devices	441,270,262	20,770,348
66	(366) Underground Conduit	134,307,317	5,422,685
67	(367) Underground Conductors and Devices	388,679,353	21,430,526
68	(368) Line Transformers	436,348,392	15,298,006
69	(369) Services	262,804,810	3,820,200
70	(370) Meters	184,764,838	5,189,406
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	268,743,243	14,060,402
74	(374) Asset Retirement Costs for Distribution Plant	259,797	-74,247
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,928,136,047	125,185,187
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	6,730,374	
87	(390) Structures and Improvements	146,641,471	-4,474
88	(391) Office Furniture and Equipment	10,157,178	1,033,826
89	(392) Transportation Equipment	21,026,594	1,352,946
90	(393) Stores Equipment	284,080	
91	(394) Tools, Shop and Garage Equipment	3,393,661	262,359
92	(395) Laboratory Equipment	6,246,299	250,181
93	(396) Power Operated Equipment	49,197,522	3,917,183
94	(397) Communication Equipment	10,038,497	-119,188
95	(398) Miscellaneous Equipment	6,746,576	-897,374
96	SUBTOTAL (Enter Total of lines 86 thru 95)	260,462,252	5,795,459
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	-1,261	-293
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	260,460,991	5,795,166
100	TOTAL (Accounts 101 and 106)	8,675,393,719	287,738,658
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	8,675,393,719	287,738,658

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		719	78,709,006		48
53,963			4,689,372		49
1,482,414		4,667,524	434,804,384		50
637		-719	5,414,270		51
2,522,494		-151,202	320,921,035		52
2,346,964		57,172	187,862,571		53
			20,724,924		54
77,601		94,030	55,524,865		55
			74,386		56
					57
6,484,073		4,667,524	1,108,724,813		58
					59
260,767			52,816,592		60
5,351		-1,742	4,910,716		61
1,939,443		130,681	365,581,631		62
					63
5,465,761			419,374,574		64
3,415,494			458,625,116		65
150,115			139,579,887		66
1,831,909			408,277,970		67
8,972,329			442,674,069		68
124,961			266,500,049		69
7,643,617			182,310,627		70
					71
					72
2,979,846			279,823,799		73
			185,550		74
32,789,593		128,939	3,020,660,580		75
					76
					77
					78
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					81
					82
					83
					84
					85
			6,730,374		86
208,811		10,462	146,438,648		87
1,499,819			9,691,185		88
1,322,972		-2,519,068	18,537,500		89
13,838			270,242		90
180,590			3,475,430		91
420,111			6,076,369		92
3,717,302		2,522,934	51,920,337		93
415,712		-25,162	9,478,435		94
20,395		14,667	5,843,474		95
7,799,550		3,833	258,461,994		96
					97
			-1,554		98
7,799,550		3,833	258,460,440		99
64,508,081		-531,042	8,898,093,254		100
					101
					102
					103
64,508,081		-531,042	8,898,093,254		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Schedule Page: 213 Line No.: 1 Column: a

Carolina Gas Transmission Corporation (an associated company until sold by SCANA in 2015) rents office space in a facility that is owned by the Company and is classified as Electric Utility Plant on the Company's books.

SCANA Energy Marketing, Inc. (an associated company) also rents office space in a facility that is owned by the Company and is classified as Common Utility Plant on the Company's books.

The Company charges a rental fee to SCANA Communications, Inc. (an associated company until sold by SCANA in 2015) for communication tower site ground leases.

SCANA Services Inc., utilizes certain assets, including both office space and equipment, that are owned by SCE&G and classified as electric, gas and common utility plant on the books of SCE&G. SCE&G charges SCANA Services a rental fee for such asset usage.

See Transactions with Associated Companies Schedule on page 429 for additional details.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Steam Production	
2	Wateree Ash Landfill Cells #6-8	11,040,820
3	Jasper Steam Heat Tracing/Freeze Protect	6,774,148
4	Jasper Steam High Energy Pipe	1,722,272
5	Urquhart #1 High Pressure Casing	1,137,757
6	Urquhart #2 High Pressure Casing	1,137,670
7	Wateree Dry Sorbent Injection System	1,104,421
8	Urquhart Mark VI HMI (Hardware)	758,427
9	Urquhart #1 480/208 Breakers	745,293
10	Wateree #2 Boiler Ignitors	727,978
11	Wateree #1 Migration (Hardware)	665,667
12	Wateree #2 High Pressure Feedwater Heater #2	590,120
13	Minor Steam Production	4,470,322
14	Nuclear Production	
15	VCS #2 and #3 Work Order	2,742,370,758
16	VCS #1 Dry Cask Storage Facility (ISFSI)	62,624,397
17	VCS #1 NFPA 805 - Circuit Protection	8,657,379
18	VCS #1 Head Replacement	6,732,806
19	VCS #1 Redundant Instrument Loop	6,674,283
20	VCS #1 NFPA 805 - Communications System	6,321,460
21	VCS #1 1DX to 1 DA Re-Route	6,023,731
22	VCS #1 Security Facility	1,753,549
23	VCS #1 NFPA 805 - RCP Seal Replacement	2,968,269
24	VCS #1 Spent Fuel Storage Canisters	2,877,867
25	VCS #1 Generator Field Replacement	2,771,323
26	VCS #1 New CW Pump Shaft & Can	2,624,146
27	VCS #1 EFW System Flow Control - CIPP	2,242,130
28	VCS #1 S/R Bravo Chiller Replacement	2,019,292
29	VCS #1 AB Truck Bay LWPS Modification	1,771,524
30	VCS #1 Fukushima FLEX Response Strategy	1,589,360
31	VCS #1 Charlie FW Pump Turbine Rotor	1,374,441
32	VCS #1 NFPA 805 Incipient Detection System	1,362,598
33	VCS #1S/R Charlie Chiller Replacement	1,217,707
34	VCS #1 Defensive Strategy Enclosures	1,214,723
35	VCS #1 Hardwired Communications System	1,123,466
36	VCS #1 Replace RMWST Heat Tracing	960,089
37	VCS #1 FLEX DG to Battery Chargers	860,187
38	VCS #1 SW Chemical Treatment Equipment	843,276
39	VCS #1 NFPA805 - MCB Disconnect Switch	827,862
40	VCS #1 FLEX RCS Makeup and Boration	764,725
41	VCS #1 S/R PORV Controls	737,921
42	VCS #1 FLEX Feed Header	713,464
43	TOTAL	3,264,008,059

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	VCS #1 Bravo FWP Turbine Blade Repl.	684,594
2	VCS #1 RBCU Industrial Coolers	593,354
3	VCS #1 EEB Elec. FLEX Support Functions	513,109
4	Minor Nuclear Production	5,913,089
5	Hydro Production	
6	Fairfield Pump 13.8Kv Breakers	2,463,803
7	Minor Hydro Production	1,216,349
8	Electric Other Production	
9	Urquhart Gas Turbine #5 & #6 Heat Tracing	3,345,862
10	Urquhart Gas Turbine #3 Generator Stator Rewind	617,874
11	Minor Electric Other Production	555,827
12	Overhead Transmission Lines	
13	Yemassee-Burton 230 (115) kV	11,913,239
14	Hagood - Bee St. 115kV Line	7,803,265
15	Clemson Wind Turbine 115kV Tap	2,615,264
16	Thomas Isl.-Jack Primus 115kV R/W	1,997,607
17	Parr Area Lines: Lightning Imp	1,739,241
18	Faber Place - Hagood 115kV Line #1	1,629,314
19	Mt Pleasants - Osc Park 115kV: Rebld B795	1,474,047
20	Victory Gardens-Richland Mall 115kV	1,469,827
21	Allendale Proj. #4136B: 46 kV Line Sw Replace	1,366,198
22	Clemson Wind Turbine 115kV Tap: R/W	1,158,376
23	Lyles - Williams Street 115kV Line	840,809
24	Thomas Is. Jack Primus 115: #0270B	530,112
25	Minor Overhead Transmission Lines	2,826,618
26	Overhead Transmission Lines NND	
27	VCS2-LMT 230kV Line #2	24,315,455
28	VCS2-St. George 230 kV Line #1 & #2	20,033,920
29	VCS1-Killian(Winn-Blythwd)230kV(C)	19,261,024
30	VCS2-St. George 230 kV Line #2	18,299,378
31	VCS1-Killian(Blywd-Killian)230kV(C)	11,695,128
32	VCS1-Killian(WinnJct-Winn)230kV(C)	10,934,321
33	VCS2-St. George 230 kV Line #1/#2	8,058,080
34	VCS2-St. George 230 kV Line #1	6,247,286
35	Denny Terrace-Lyles 230 kV	4,254,917
36	Saluda Hyd-Newberry 115kV Proj. 94Q	4,227,832
37	VCS1-Killian 230kV Line: R/W (C)	4,012,418
38	VCS2-St. George 230 kV Line #1 & #2	3,187,699
39	VCS2-LMT 230 kV Line #1	3,060,293
40	Reterm Denny Terrace Proj. 0090N4	2,812,967
41	VCS1-DT (VCS1-Winn Jct) 230 kV	2,118,716
42	Parr-Winn 115 #1 Reloc Parr-Switch	1,244,179
43	TOTAL	3,264,008,059

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Reterm Duke Newport* Proj. 0090M1	1,031,763
2	VCS1-Killian(VCS1-WinnJct)230 kV(C)	1,014,862
3	Reterm Ward 230kV Proj. 0090N2	944,942
4	McMeekin-Lake Murray Trans. 115 kV	888,683
5	Project #0091F: Parr-Midway DC 115	829,089
6	Parr-Denny Terrace 115kV #14 Line	759,779
7	Saluda Hydro-LMT 115 kV	643,851
8	Saluda River-Lyles 230kV BLRA	577,958
9	Minor Overhead Transmission Lines NND	1,902,189
10	Overhead Transmission Lines Non BLRA	
11	Orangeburg-St. George 115 kV #1/#2	16,305,385
12	Saluda Hydro-Williams St. 115 kV	6,877,416
13	Orangeburg-St.George 115 kV Line #1	1,700,929
14	Lake Murray-Saluda R.-Lyles 230 kV	618,789
15	Minor Overhead Transmission Lines Non BLRA	1,826,317
16	UG Transmission Lines	
17	Charleston St-Bview Cable Replace/Repair	619,157
18	Minor UG Transmission Lines	
19	Transmission Substation	
20	Urquhart Add Switch House	2,398,842
21	CIP Hut IST/Telecom Equip HW	1,345,011
22	Cainhoy 230-115kV Trans. Sub - Cons	1,176,162
23	Wateree230kV Substation #2531	1,141,343
24	Lyles: Add 230kV Terminal To SRT	870,889
25	Saluda River Trans: Add 2 230kV Terms	615,989
26	Minor Transmission Substation	4,062,977
27	Transmission Substation NND	
28	Saluda River 230/115kV: Construct	9,191,159
29	Saluda River 230/115kV Sub Site	3,355,681
30	Various 115kv PRCB's: Upgrade	555,852
31	Minor Transmission Substation NND	3,252,815
32	Distribution Substation	
33	Gill Creek 115KV Sub-Construct	3,418,098
34	Laurel Bay 115-12kv Sub Construct	1,740,539
35	Jack Primus 115-23kv Sub: Construct	1,545,234
36	Mt Pleasant:Rep 3 115kv OCB's	1,472,478
37	Various SPCC Distribution Subs.	999,309
38	Spare 115-12kV, 28MVA Xfm LTC	648,126
39	Minor Distribution Substation	1,900,769
40	Customer Substation	
41	Clemson W.T. Sub: Construct 115/23	768,419
42	Devro: Add 115-13.8kV Trans. Bank	653,062
43	TOTAL	3,264,008,059

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Minor Customer Substation	386,092
2	Overhead Distribution Lines	
3	Truck Stock- Metro Columbia	976,472
4	Truck Stock - Runey St-Chas.	704,853
5	Truck Stock - Mt Pleasant-Chas	694,603
6	Truck Stock - Rader-Columbia	688,501
7	Gills Creek Conversion	666,088
8	Truck Stock - Piney Woods Rd.	632,517
9	Truck Stock - Aiken	530,291
10	Truck Stock - Johnston	520,150
11	Minor Overhead Distribution Lines	7,743,664
12	UG Distribution Lines	
13	Pulaski DB, College - Blossom	559,890
14	Minor UG Distribution Lines	2,542,040
15	Land and Structures	
16	Install Sys Protection Training Facility	1,024,601
17	Minor Land and Structures	294,350
18	Transportation & POE	
19	Minor Transportation & POE	1,324,781
20	Office Furniture and Equipment	
21	Control Room Video Wall Upgrade	965,524
22	EMS Upgrade - Hardware	755,098
23	Install AIX and Oracle - Hardware	649,118
24	Minor Office Furniture and Equipment	56,063
25	Communication Equipment	
26	CIPV5 - Install Routers	1,143,100
27	Minor Communication Equipment	427,584
28	Tools & Test Equipment	
29	Minor Tools & Test Equipment	72,464
30	Intangible Plant	
31	VCS - NFPA 805 Software	12,548,632
32	Software for Cyber Compliance	7,261,435
33	CHAMPS Replacement	2,703,088
34	Seismic PRA Project	6,073,997
35	Configuration Mgmt. Software	1,295,048
36	Lighting Management System	596,130
37	Workforce Time & Attend. Software	560,045
38	Minor Intangible Plant	2,003,578
39	Transmission - BLRA-VCS1	
40	VCS Sub #2561-Upgrade PrCB's	7,788,050
41	VCS#1-Upgd 2 Terms & Repl Disc Sw	4,219,970
42	VCS#1-Add Term & Repl 2 Disc Sw.	3,797,493
43	TOTAL	3,264,008,059

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	VCS1, Bus1: SCPSA Upg 8852 Add 9322	2,846,431
2	Parr Safeguard 115 kV	2,684,232
3	VCS #1 Add Pineland Terminal for VCS #1	2,068,933
4	VCS #1 Upgr 230kv 8902 & 8932	2,050,950
5	VCS #1 Upgrade Terminal 8832	1,221,871
6	VCS #2 Tie to VCS #1 Proj. 0090H	1,088,522
7	Parr 115kV Safeguard - Raise @ VCS	855,371
8	VCS #2 to VCS #1 Bus#3 Proj. 0090J	758,208
9	VCS #3 Tie to VCS #1 Bus #1: Bus Tie #1	669,611
10	Minor Transmission - BLRA-VCS1	458,439
11	Transmisson Non-BLRA - VCS1	
12	Minor Transmisson - Non-BLRA -VCS1	38,334
13	Payroll Overheads and Adjustments	-521,035
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43	TOTAL	3,264,008,059

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,236,928,993	3,236,928,993		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	236,382,735	236,382,735		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,291,301	4,291,301		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	7,122,128	7,122,128		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	247,796,164	247,796,164		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	62,616,293	62,616,293		
13	Cost of Removal	27,406,834	27,406,834		
14	Salvage (Credit)	5,981,521	5,981,521		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	84,041,606	84,041,606		
16	Other Debit or Cr. Items (Describe, details in footnote):	48,613,743	48,613,743		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,449,297,294	3,449,297,294		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	757,638,525	757,638,525		
21	Nuclear Production	569,692,644	569,692,644		
22	Hydraulic Production-Conventional	300,147,574	300,147,574		
23	Hydraulic Production-Pumped Storage	73,482,358	73,482,358		
24	Other Production	367,229,390	367,229,390		
25	Transmission	315,485,459	315,485,459		
26	Distribution	970,375,975	970,375,975		
27	Regional Transmission and Market Operation				
28	General	95,245,369	95,245,369		
29	TOTAL (Enter Total of lines 20 thru 28)	3,449,297,294	3,449,297,294		

Schedule Page: 219 Line No.: 8 Column: c

Depreciation of Asset Retirement Costs recorded as a regulatory asset.

Schedule Page: 219 Line No.: 12 Column: c

Retirements per page 207, Line 100 Column (d)	$64,508,081
Less: Intangible Plant per Page 205, Line 5 column (d)	(390,991)
Capital Lease Asset Reductions Recorded in Accordance with USofA General Instruction No. 20 shown as Plant Retirements	(1,500,797)
Total	$62,616,293

Schedule Page: 219 Line No.: 16 Column: c

Cost of removal reclassified from Other Regulatory Liabilities (account 254)	$61,995,687
Loss on ARC retirements reclassified to Regulatory Assets	(13,432,504)
Loss on Disposal on Vehicles	93,650
Book Cost of Land Retired	652,652
Transfers and Adjustments	(695,742)
Total	$48,613,743

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	84,448,877	68,741,416	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	82,139,562	88,633,157	Electric
8	Transmission Plant (Estimated)	6,813,498	6,673,824	Electric
9	Distribution Plant (Estimated)	22,858,723	25,555,795	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	388,848	353,195	Fleet
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	112,200,631	121,215,971	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)		8	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	196,649,508	189,957,395	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year	125,547.60	947,813	45,625.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	-24,783.00		27,845.00	
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	29,657.40	279,088		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	71,107.20	668,725	73,470.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	659.50		659.50	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	659.50			
40	Balance-End of Year			659.50	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	659.50	400		
45	Gains	659.50	400		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
45,625.00		45,625.00		1,186,250.00		1,448,672.60	947,813	1
								2
								3
				45,625.00		45,625.00		4
						3,062.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						29,657.40	279,088	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
45,625.00		45,625.00		1,231,875.00		1,467,702.20	668,725	29
								30
								31
								32
								33
								34
								35
659.50		659.50		32,315.50		34,953.50		36
				1,319.00		1,319.00		37
								38
				659.50		1,319.00		39
659.50		659.50		32,975.00		34,953.50		40
								41
								42
								43
				659.50	38	1,319.00	438	44
				659.50	38	1,319.00	438	45
								46

Schedule Page: 228 Line No.: 4 Column: j

Vintage 2044 allowances for the SO2 Acid Rain Program.

Schedule Page: 228 Line No.: 5 Column: b

The EPA removed Vintage 2012 for the CSAPR program.

Schedule Page: 228 Line No.: 5 Column: d

The EPA distributed revintaged allowances for Vintage 2015 for the CSAPR program.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year	44,064.10	8,762		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			10,875.00	
5	Returned by EPA	-12,797.00		12,797.00	
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	8,056.40	1,955		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	GENCO - Associated Co	2,056.00			
23					
24					
25					
26					
27					
28	Total	2,056.00			
29	Balance-End of Year	21,154.70	6,807	23,672.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						44,064.10	8,762	1
								2
								3
						10,875.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						8,056.40	1,955	18
								19
								20
								21
						2,056.00		22
								23
								24
								25
								26
								27
						2,056.00		28
						44,826.70	6,807	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 4 Column: d

Vintage 2015 allowances for the CAIR programs.

Schedule Page: 229 Line No.: 5 Column: b

The EPA removed Vintage 2012 for the CSAPR programs.

Schedule Page: 229 Line No.: 5 Column: d

The EPA distributed revintaged allowances for Vintage 2015 for the CSAPR programs.

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant:					
22						
23	Unrecovered Plant related to the					
24	retirement of Canadys Unit No. 1					
25	SCPSC authorization received					
26	12/2012. (Docket No. 2012-218-E,					
27	Order 2012-251) Amortization					
28	over approximately 14 years					
29	beginning 1/2013.	19,852,123	-193,815	407	1,607,593	16,636,938
30						
31	Unrecovered Plant related to the					
32	retirement of Canadys Unit No. 2					
33	and Unit No. 3. SCPSC					
34	authorization received 9/2013.					
35	(Docket No. 2013-276-E, Order					
36	2013-649) Amortization over					
37	approximately 12 years beginning					
38	1/2014.	133,317,416	7,075,914	407	12,270,624	120,024,240
39						
40	Unrecovered Plant associated with					
41	planned early retirement of					
42	Urquhart Unit No. 3.	557,755				557,755
43						
44	Unrecovered Plant associated with					
45	planned early retirement of					
46	McMeekin Station.	398,695				398,695
47						
48						
49	TOTAL	154,125,989	6,882,099		13,878,217	137,617,628

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Santee Cooper - North Plum Branch				
3	Facilities Study	1,144	408/431/561/926		
4					
5	Santee Cooper - Longpoint				
6	Facilities Study	524	408/431/561/926		
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 22 Column: a

Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
Infigen Energy US Development Feasibility Study - Columbia Solar	-		1,000	253
Infigen Energy US Development Feasibility Study - Fairfax Solar	-		1,000	253
Old Mill Feasibility Study	1,147	408 / 431 / 561 / 926	0	
Old Mill Facilities Study	608	107/ 108 / 408 / 566 / 593 / 926	1,000	253
Palmetto Plains Solar System Impact Study	6,712	408 / 561 / 566 / 926	50,000	253
Palmetto Plains Solar Facilities Study	-		100,000	253
Sustainable Energy Solutions Feasibility Study - Southern Current One	2,536	408 / 561 / 566 / 926	1,000	253
Sustainable Energy Solutions Feasibility Study - Hampton Solar I	7,612	408 / 561 / 566 / 926	1,000	253
Sustainable Energy Solutions System Impact Study - Southern Current One	3,061	408 / 561 / 566 / 926	10,000	253
Sustainable Energy Solutions System Impact Study - Hampton Solar II	2,153	408 / 561 / 926	9,000	253
Sustainable Energy Solutions System Impact Study - Hampton Solar I	-		7,500	253
Sustainable Energy Solutions System Impact Study - Estill Solar II	-		15,000	253
Sustainable Energy Solutions System Impact Study - Estill Solar I	422	408 / 561 / 566 / 926	11,000	253
Sustainable Energy Solutions Feasibility Study - Gaston Solar I	-		1,000	253
Sustainable Energy Solutions Feasibility Study - Gaston Solar II	-		1,000	253
Otarre Solar Feasibility Study	1,161	408 / 431 / 561 / 566 / 926	1,000	253
Fast Track Screen Feasibility Study	566	408 / 431 / 561 / 926	500	253
Otarre Solar System Impact Study	3,211	408 / 431 / 561 / 566 / 926	1,000	253
Otarre Solar Facilities Study	2,394	408 / 561 / 566 / 926	1,000	253
TWE Bowman Solar Project Feasibility Study- TWE Bowman Solar Project	4,554	408 / 561 / 566 / 926	1,000	253

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Income Taxes	239,386,100	29,290,200	282	7,079,000	261,597,300
2	Amt. Undercollected - Elec. Fuel Adjustment Clause	60,509,407	102,419,449	449/173	98,543,163	64,385,693
3	Columbia & Charleston Franchise	30,681,761		407	4,828,826	25,852,935
4	Gas Water Heater Rebate Program (2009-2019)	3,673,639	3,685,980	912	3,023,110	4,336,509
5	Decommissioning Asset Ret. Obligation	52,133,033	9,900,848	Various	14,483,793	47,550,088
6	MGP Environmental Remediation	36,707,244	20,705,093	735	21,888,591	35,523,746
7	Long-Term Disability Gas (2005-2014)	113,004		926	113,004	
8	Deferred ARO Acretion & Depreciation Costs	284,694,382	26,435,599	Various	25,133,291	285,996,690
9	Interest Rate Derivatives	123,526,743	323,393,742	244/427	2,275,589	444,644,896
10	Deferred Employee Benefit Plan Costs-Gas (ASC 715)	18,328,721	29,897,097	228.3/242	18,409,317	29,816,501
11	Deferred Employee Benefit Plan Costs-Elec (ASC 715)	121,597,290	208,838,051	228.3/242	122,197,630	208,237,711
12	Gas Customer Awareness Program (11/2009-10/2019)	968,343	275,196	913	415,219	828,320
13	Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	5,241,598		530	183,816	5,057,782
14	Deferred Capacity Charges (7/2010-7/2020)	4,395,760		555	1,525,713	2,870,047
15	Deferred Capacity Charges	1,907,959	102,152			2,010,111
16	Electric Demand Side Management	54,129,418	29,438,735	Various	21,866,010	61,702,143
17	Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	8,791,577		555	282,658	8,508,919
18	Economic Development Grants (10/2009-12/2026)	6,626,016	250,000	921	735,101	6,140,915
19	Incremental Rtl Elec Rate Case Exp (7/2010-12/2015)	179,684		928	100,242	79,442
20	Major Maintenance Accrual and Interest	6,477,534	10,827,246	Various	9,786,160	7,518,620
21	Deferred Pension Cost - Gas (11/2013-1/2027)	13,455,128		926	1,029,507	12,425,621
22	Deferred Pension Cost - Electric (1/2013-12/2042)	60,665,096		926	1,987,834	58,677,262
23	Environmental Compliance Studies (7/2010 - 7/2020)	620,038		506	94,783	525,255
24	Deferred Pollution Control Costs -					
25	Wateree (1/2013-9/2040)	28,341,776		407.3	1,061,940	27,279,836
26	Research and Development Grant (1/2013-12/2047)	3,400,000		930.2	100,000	3,300,000
27	Environmental Remediation Cost	1,217,173	1,233,240	Various	1,540,490	909,923
28	Amount Undercollected - Gas Cost Adjustment	5,401,385	58,397,544	Various	58,047,860	5,751,069
29	Gas WNA Cap - Winter 2012 (11/2012-10/2015)	2,403,682		480/481	836,063	1,567,619
30	Fukushima Compliance Costs	1,956,682	1,894,287	Various	850,969	3,000,000
31	Wholesale Fuel Undercollection	1,573,575	1,554,029	447	1,754,785	1,372,819
32	Undercollected Electric Pension Expense	3,091,829	1,870,162	926	4,961,991	
33	Deferred Long-Term Capacity Contract	252,760	13,680,979	555/565	10,802,787	3,130,952
34	Carrying Costs Accrual	2,922,670	5,819,647			8,742,317
35	Nuclear Refueling Outage Costs		3,854,938	254	3,854,938	
36	Gas Pipeline Integrity Costs		448,495			448,495
37	DER and NET Metering Costs		23,866			23,866
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	1,185,371,007	884,236,575		439,794,180	1,629,813,402

Schedule Page: 232 Line No.: 2 Column: a

SCPSC Docket No. 2014-2-E

Schedule Page: 232 Line No.: 3 Column: a

SCPSC Docket No. 2002-223-E

Amounts are being amortized through cost of service rates over approximately twenty years.

Schedule Page: 232 Line No.: 4 Column: a

SCPSC Docket No. 89-245-G
SCPSC Docket No. 2008-155-G

Schedule Page: 232 Line No.: 5 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 6 Column: a

SCPSC Docket No. 2005-113-G

Schedule Page: 232 Line No.: 7 Column: a

SCPSC Docket No. 2005-113-G

Schedule Page: 232 Line No.: 8 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 9 Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

Schedule Page: 232 Line No.: 12 Column: a

SCPSC Docket No. 2007-418-G

Schedule Page: 232 Line No.: 13 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 14 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 15 Column: a

SCPSC Docket No. 2008-230-E

Schedule Page: 232 Line No.: 16 Column: a

Amortization of deferred balance is a function of customer usage per a Rate Rider mechanism approved by the SCPSC in Docket No. 2013-50-E, Docket No. 2013-208-E and Docket No. 2014-44-E.

Schedule Page: 232 Line No.: 17 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 18 Column: a

SCPSC Docket No. 2009-497-E
SCPSC Docket No. 2011-264-E
SCPSC Docket No. 2012-246-E

Schedule Page: 232 Line No.: 19 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 20 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 21 Column: a

SCPSC Docket No. 2009-35-G
SCPSC Docket No. 2013-6-G

Schedule Page: 232 Line No.: 22 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 23 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 25 Column: a

SCPSC Docket No. 2008-393-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 26 Column: a

SCPSC Docket No. 2011-513-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 27 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 28 Column: a

SCPSC Docket No. 2014-5-G

Per SCPSC Docket No. 2005-5-G commodity and demand components of purchased gas cost are now recovered separately. Balances for these components as of December 31, 2014 are as follows:

Commodity	$15,093,527
Demand	(9,342,458)
Total	$ 5,751,069

Schedule Page: 232 Line No.: 29 Column: a

SCPSC Docket No. 2012-6-G
SCPSC Docket No. 2014-6-G

Schedule Page: 232 Line No.: 30 Column: a

SCPSC Docket No. 2012-277-E

Schedule Page: 232 Line No.: 32 Column: a

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2014-88-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

Schedule Page: 232 Line No.: 33 Column: a

SCPSC Docket No. 2013-276-E

Schedule Page: 232 Line No.: 34 Column: a

In SCPSC Docket No. 2013-336-E, the SCPSC approved the exclusion from rate base of ADIT assets associated with the treatment of capitalized interest related to new nuclear construction. The SCPSC also approved the accrual of carrying costs on the balance of the ADIT assets removed from rate base, with such carrying costs being deferred as a regulatory asset.

Schedule Page: 232 Line No.: 35 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 36 Column: a

SCPSC Docket No. 2014-461-G

Per SCPSC order, amortization in a levelized annual amount of $1,881,143 will begin in November 2015.

Schedule Page: 232 Line No.: 37 Column: a

SCPSC Docket No. 2015-54-E

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Accts Rec. - Post Retirement					
2	Benefits	26,695,212	23,872,112	Various	17,645,611	32,921,713
3	Charleston Garage Revenue Bond					
4	Long-Term	3,954,270	355,121	143	1,519,321	2,790,070
5	5 year Commitment Fees	4,706,404	2,400,542	427	1,692,966	5,413,980
6	3 Year Commitment Fees	270,458	891,531	427	1,039,054	122,935
7	Progress Payments/Plant Equipmt	1,769,747	15,899,146	Various	15,631,703	2,037,190
8	Director's Endowment	573,671	13,813	426.5	171,724	415,760
9	Pole Attachment Receivables	2,155,111	7,068,955	143/589	8,502,534	721,532
10	Long Term Power Plant Service					
11	Agreement (2007-2021)	1,916,711	14,510,599	107/553	14,934,534	1,492,776
12	Lease Buyout Costs	5,662,001		Various	194,250	5,467,751
13	Department of Energy Nuclear					
14	Loan Guarantee Application Fee	1,183,076				1,183,076
15	Workers' Comp Reserve	415,720	380,722	925	266,995	529,447
16	Deferred Nuclear Training Costs			253		
17	NND Transmission Lines	270,000		Various	90,000	180,000
18	Other	95,588	25,263,618	Various	25,480,531	-121,325
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47	Misc. Work in Progress	35,286,943				33,262,058
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	84,954,912				86,416,963

Schedule Page: 233   Line No.: 18   Column: f

Credit balance due primarily to CIAC awaiting distribution and clearance to capital work order(s).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Asset Retirement Obligation	154,579,630	147,217,462
3	Other Post Employment Benefits	54,521,500	64,262,400
4	Regulatory Asset / Liability, Interest Rate Derivatives	26,565,500	-21,131,900
5	Unamortized Investment Tax Credits	15,847,500	14,430,000
6	Nuclear Fuel	2,308,900	3,792,200
7	Other	36,165,100	11,246,200
8	TOTAL Electric (Enter Total of lines 2 thru 7)	289,988,130	219,816,362
9	Gas		
10	Other Post Employment Benefits	8,882,100	9,454,500
11	Asset Retirement Obligation	7,082,500	7,566,900
12	Environmental Remediation	-6,332,500	-6,822,800
13	Incentive Compensation	1,337,900	3,883,800
14	Unamortized Investment Tax Credits	1,974,899	1,435,599
15	Other	3,181,000	3,259,600
16	TOTAL Gas (Enter Total of lines 10 thru 15	16,125,899	18,777,599
17	Other (Specify): Non Operating	45,999,650	48,283,430
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	352,113,679	286,877,391

Notes

Line 7 "Other":

	Balance at Beg. of Year	Balance at End of Year
Early Retirement Programs	$ 3,962,100	$ 3,653,500
Major Maintenance	(2,825,900)	(2,876,000)
Storm Damage Reserve	10,442,100	2,092,600
Nuclear Refueling Costs	6,425,900	2,013,200
Vacation Accrual	1,727,500	1,760,800
Uncollectible Accounts	936,800	1,112,300
Reserve for Injuries and Damages	1,596,900	1,059,700
Incentive Compensation	2,149,800	897,700
Long Term Disability	5,260,100	733,000
State Credits	4,744,200	-
Litigation	1,051,900	-
All Other	693,700	799,400
Total	$36,165,100	$11,246,200

Line 15 "Other" :

	Balance at Beg. of Year	Balance at End of Year
Long Term Disability	$ 860,000	$ 969,400
Inventory Capitalization Under 263A	722,500	771,400
Early Retirement Programs	700,800	645,600
Vacation Accrual	298,600	330,600
Reserve for Injuries and Damages	258,700	178,700
Uncollectible Accounts	145,100	169,300
All Other	195,300	194,600
Total	$ 3,181,000	$ 3,259,600

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock Issued	50,000,000		
3	Total Common	50,000,000		
4				
5				
6	Account 204:			
7	Preferred Stock Issued	20,000,000		
8	Total Preferred	20,000,000		
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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
40,296,147	576,405,122					2
40,296,147	576,405,122					3
						4
						5
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1,000	100,000					7
1,000	100,000					8
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Schedule Page: 250 Line No.: 2 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: e

These shares are held by SCANA Corporation and do not pay a dividend.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received from Stockholders:	
2	Cash donations by former parent company, General Gas & Electric	
3	Corporation	240,000
4	Equity advance from SCANA to SCE&G from issuance of 2.3 million	
5	shares of common stock (1992)	89,941,500
6	Equity advance from SCANA to SCE&G from issuance of 404,222 shares	
7	of SCANA common stock under the Dividend Reinvestment and Stock	
8	Purchase Plan and 422,082 shares of SCANA common stock under the	
9	Stock Purchase Savings Plan (1992)	36,895,774
10	Equity advance from SCANA to SCE&G from issuance of 529,954 shares	
11	of SCANA common stock under the Dividend Reinvestment and Stock	
12	Purchase Plan and 705,498 shares of SCANA Common Stock under	
13	the Stock Purchase Saving Plan (1993)	58,141,500
14	Equity advance from SCANA to SCE&G from issuance of 595,438 shares	
15	of SCANA common stock under the Dividend Reinvestment and Stock	
16	Purchase Plan and 781,354 shares of SCANA common stock	
17	under the Stock Purchase Savings Plan (1994)	43,425,899
18	Equity advance from SCANA to SCE&G from issuance of 1,434,664	
19	shares of SCANA common stock under the SCANA Investor Plus Plan	
20	and 1,630,993 shares of SCANA common stock under the Stock	
21	Purchase Savings Plan (1996)	53,658,065
22	Equity advance from SCANA to SCE&G from issuance of 4.5 million	
23	shares of SCANA common stock (1995)	85,845,000
24	Equity advance from SCANA to SCE&G from issuance of 1,118,366	
25	shares of SCANA common stock under the SCANA Investor Plus Plan	
26	and 1,393,761 shares of SCANA common stock under the	
27	Stock Purchase Savings Plan (1996)	49,141,871
28	Equity advance from SCANA to SCE&G from issuance of 170,524 shares	
29	of SCANA common stock under the SCANA Investor Plus Plan and	
30	the issuance of 342,409 shares of SCANA common stock under	
31	the Stock Purchase Savings Plan (1997)	12,147,617
32	Reclass of 2001-2003 Capital Contributions from Parent from 211	
33	account "Misc Paid-In Capital"	197,911,200
34	Repayment of Capital Contributions from Parent (2004)	-3,206,660
35	Equity advance from SCANA to SCE&G from issuance of 356,008 shares	
36	of SCANA common stock under the SCANA Investor Plus Plan and	
37	the issuance of 780,472 shares of SCANA common stock under the	
38	Stock Purchase Savings Plan (2004)	41,728,531
39	Reclass of 2005 Capital Contributions from Parent from	
40	TOTAL	1,987,672,935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	account 211 "Misc. Paid in Capital."	4,591,300
2	Equity advance from SCANA to SCE&G from issuance of SCANA common stock	
3	under the SCANA Investor Plus Plan and the Stock Purchase	
4	Saving Plan (2005)	34,697,793
5	Equity advance from SCANA to SCE&G based on SCE&G's funding	
6	requirements	1,094,496,916
7	Income tax benefit true-up	77,764,807
8	Equity advance from SCANA to SCE&G from issuance of SCANA Common Stock	100,500,000
9	Subtotal - Account 208	1,977,921,113
10		
11	Account 209 - Reduction in Par or stated value of Capital Stock	
12	Subtotal - Account 209	
13		
14	Account 210 - Gain on Resale or Cancellation of Reacquired Capital	
15	Stock:	
16		
17	Subtotal - Account 210	
18		
19		
20	Account 211 - Miscellaneous Paid - In - Capital:	
21	Merger of Florence Gas Division	6,284,464
22	Revaluation of fixed capital and related depreciation reserves	
23	(1940)	8,547,035
24	Merger of Lexington Water Power Company (1943)	5,418,114
25	Reserves for amounts in excess of original cost of utility plant	
26	(1943)	-9,547,035
27	Discount on purchase of 20 shares of 5% series, $50 par value	
28	preferred stock (1944)	100
29	Revaluation of Florence-Darlington gas properties (1944)	-276,426
30	Disposition of electric and common plant adjustments (1945)	39,140
31	Disposition of other physical property adjustments (1945)	82,567
32	Disposition of gas plant intangibles (1945)	-644,761
33	Adjustments of 1941 land sales by Lexington Water Power	
34	Company (1949)	12,331
35	Funds received from Script Agent under 1946 Plan for Stock	
36	Distribution by former Parent Company (1952, 1953)	98,308
37	Capital Contributions from Parent (2001)	32,908,300
38	Capital Contributions from Parent (2002)	156,780,200
39	Capital Contributions from Parent (2003)	8,222,700
40	TOTAL	1,987,672,935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Reclass of 2001-2003 Capital Contributions from Parent to	
2	account 208 "Donations Received from Stockholders" (2004)	-197,911,200
3	Other	-262,015
4	Equity advance representing the true up of the benefit allocation	
5	relating to the SCANA tax benefit	4,591,300
6	Reclass of 2005 Capital Contributions from Parent to	
7	account 208 "Donations Received from Stockholders."	-4,591,300
8	Subtotal - Account 211	9,751,822
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40	TOTAL	1,987,672,935

Schedule Page: 253.1 Line No.: 6 Column: b

During 2014, the Company received equity advances from SCANA in the amount of $74,097,559. The entry was:

Account	Debit	Credit
131 - Cash	$74,097,559	
208 - Donations Received from Stockholders		$74,097,559

Schedule Page: 253.1 Line No.: 7 Column: b

During 2014, the Company recorded the following transaction associated with the income tax benefit allocation from SCANA:

Account	Debit	Credit
131 - Cash	$6,688,247	
208 - Donations Received from Stockholders		$6,688,247

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense, no par value	4,335,379
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22	TOTAL	4,335,379

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LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2			
3	First Mortgage Bonds:		
4	6.625% Series, due 2032	300,000,000	2,928,187
5			2,397,000 D
6			
7	4.50% Series, due 2064	300,000,000	2,625,000
8			3,186,000 D
9			
10	5.25% Series, due 2035	100,000,000	1,032,840
11			1,821,000 D
12			
13	5.30% Series, due 2033	300,000,000	2,678,847
14			579,000 D
15			
16	5.25% Series, due 2018	250,000,000	2,443,883
17			615,000 D
18			
19	5.80% Series, due 2033	200,000,000	1,785,478
20			646,000 D
21			
22	6.25% Series, due 2036	125,000,000	1,240,777
23			421,250 D
24			
25	6.05% Series, due 2038	250,000,000	2,611,037
26			242,500 D
27			
28	6.05% Series, due 2038	110,000,000	962,500
29			5,365,800 D
30			
31	4.35% Series, due 2042	250,000,000	2,559,708
32			207,500 D
33	TOTAL	4,088,541,381	35,454,328

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
01-31-2002	02-01-2032	01-31-2002	02-01-2032	300,000,000	19,875,000	4
						5
						6
06-01-2014	06-01-2064	06-01-2014	06-01-2064	300,000,000	8,025,000	7
						8
						9
03-08-2005	03-01-2035	03-08-2005	03-01-2035	100,000,000	5,250,000	10
						11
						12
05-21-2003	05-15-2033	05-21-2003	05-15-2033	300,000,000	15,900,000	13
						14
						15
11-06-2003	11-01-2018	11-06-2003	11-01-2018	250,000,000	13,125,000	16
						17
						18
01-23-2003	01-15-2033	01-23-2003	01-15-2033	200,000,000	11,600,000	19
						20
						21
06-27-2006	07-01-2036	06-27-2006	07-01-2036	125,000,000	7,812,500	22
						23
						24
01-14-2008	01-15-2038	01-14-2008	01-15-2038	250,000,000	15,212,725	25
						26
						27
06-24-2008	01-15-2038	06-24-2008	01-15-2038	110,000,000	6,473,500	28
						29
						30
01-30-2012	02-01-2042	01-30-2012	02-01-2042	250,000,000	10,875,000	31
						32
				4,028,973,972	209,983,057	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.35% Series, due 2042	250,000,000	2,559,709
2			-21,570,000 P
3			
4	6.50% Series, due 2018	300,000,000	2,214,194
5			861,000 D
6			
7	6.05% Series, due 2038	175,000,000	1,916,924
8			728,000 D
9			
10	5.50% Series, due 2039	150,000,000	1,517,157
11			1,179,000 D
12			
13	3.22% Series, due 2021	30,000,000	329,625
14			
15	5.45% Series, due 2041	250,000,000	2,187,500
16			917,500 D
17			
18	5.45% Series, due 2041	100,000,000	1,361,577
19			-2,799,000 P
20			
21	4.60% Series, due 2043 (State Commission Order No. 2010-660 issued 03-30-2010)	400,000,000	4,234,911
22			2,000,000 D
23			
24	Pollution Control Facilities Revenue Bonds:		
25	Industrial Revenue (4%) (State Commision Order No. 2012-936 issued 12-14-2012)	39,480,000	426,014
26			-2,694,115 P
27			
28	Industrial Revenue (3.625%) (State Commision Order No. 2012-936 issued 12-14-2012)	14,735,000	158,164
29			258,157 D
30			
31	Industrial Revenue (variable)	35,000,000	492,221
32			
33	TOTAL	4,088,541,381	35,454,328

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
07-13-2012	02-01-2042	07-13-2012	02-01-2042	250,000,000	10,875,000	1
						2
						3
10-02-2008	11-01-2018	10-02-2008	11-01-2018	300,000,000	19,500,000	4
						5
						6
03-17-2009	01-15-2038	03-17-2009	01-15-2038	175,000,000	10,681,275	7
						8
						9
12-09-2009	12-15-2039	12-09-2009	12-15-2039	150,000,000	8,250,000	10
						11
						12
10-18-2011	10-18-2021	10-18-2011	10-18-2021	30,000,000	966,000	13
						14
01-27-2011	02-01-2041	01-27-2011	02-01-2041	250,000,000	13,625,000	15
						16
						17
05-24-2011	02-01-2041	05-24-2011	02-01-2041	100,000,000	5,450,000	18
						19
						20
06-14-2013	06-15-2043	06-14-2013	06-15-2043	400,000,000	18,451,111	21
						22
						23
						24
01-15-2013	02-01-2028	01-15-2013	02-01-2028	39,480,000	1,579,200	25
						26
						27
01-15-2013	02-01-2033	01-15-2013	02-01-2033	14,735,000	534,144	28
						29
						30
12-01-2008	12-01-2038	12-01-2008	12-01-2038	34,555,000	1,023,780	31
						32
				4,028,973,972	209,983,057	33

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Amortization of Interest Rate Derivative Contracts:		
2	6.625% $300 Million due 2/1/2032		
3	5.80% $200 Million due 1/15/2033		
4	6.25% $125 Million due 7/1/2036		
5	5.30% $300 Million due 5/21/2033		
6	5.25% $250 Million due 11/1/2018		
7	5.25% $100 Million due 3/1/2035		
8	6.05% $250 Million due 1/15/2038		
9	6.05% $110 Million due 1/15/2038		
10	6.05% $175 Million due 1/15/2038		
11	5.50% $150 Million due 12/15/2039		
12	5.45% $250 Million due 2/1/2041		
13	5.45% $100 Million due 2/1/2041		
14	4.35% $250 Million due 2/01/2042		
15	4.35% $250 Million due 2/01/2042		
16	4.60% $75 Million due 6/14/2043		
17	4.60% $75 Million due 6/14/2043		
18	4.60% $90 Million due 6/14/2043		
19	4.60% $80 Million due 6/14/2043		
20	4.60% $80 Million due 6/14/2043		
21	$35 Million SIFMA due 11/30/2038		
22	4.5% $300 Million due 06/01/2064		
23			
24	SUBTOTAL - Account 221	3,929,215,000	32,627,845
25			
26	Account 224 - Other Long Term Debt:		
27	State Infrastructure Bank Loan	59,000,000	
28	Variable Rate Lines of Credit		
29	Contract on Natural Gas Distribution system		
30	Acquired from Charleston AFB	424,844	
31	Commitment Fees		
32	Nuclear Fuel Contract	99,901,537	2,826,483 D
33	TOTAL	4,088,541,381	35,454,328

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
		01-31-2002	02-01-2032		-28,276	2
		01-23-2003	01-15-2033		-4,619	3
		06-27-2006	07-01-2036		-173,796	4
		05-21-2003	05-15-2033		287,581	5
		11-06-2003	11-01-2018		271,819	6
		03-08-2005	03-01-2035		41,417	7
		01-14-2008	01-15-2038		231,407	8
		06-24-2008	01-15-2038		-8,933	9
		03-17-2009	01-15-2038		310,893	10
		12-09-2009	12-15-2039		-387,833	11
		01-27-2011	02-01-2041		257,304	12
		05-24-2011	02-01-2041		182,209	13
		01-30-2012	02-01-2042		-236,339	14
		07-13-2012	02-01-2042		-24,683	15
		06-14-2013	06-15-2043		244,262	16
		06-14-2013	06-15-2043		244,832	17
		06-14-2013	06-15-2043		-301,763	18
		06-14-2013	06-15-2043		-270,062	19
		06-14-2013	06-15-2043		-262,966	20
		12-01-2013	11-30-2038		-203,758	21
		06-01-2014	06-01-2064		86,846	22
						23
				3,928,770,000	205,339,777	24
						25
						26
						27
						28
						29
				302,435	14,344	30
					4,628,936	31
03-01-2013	11-01-2016	03-01-2013	11-01-2016	99,901,537		32
				4,028,973,972	209,983,057	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	SUBTOTAL - Account 224	159,326,381	2,826,483
2			
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9			
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12			
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29			
30			
31			
32			
33	TOTAL	4,088,541,381	35,454,328

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
				100,203,972	4,643,280	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
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						17
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						21
						22
						23
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						25
						26
						27
						28
						29
						30
						31
						32
				4,028,973,972	209,983,057	33

Schedule Page: 256 Line No.: 1 Column: c

With respect to unamortized amounts (premium, discount or expense), of debt redeemed, the Company follows the provisions set forth in General Instruction No. 17 of the Uniform System of Accounts. The Company records any unamortized amounts related to the redeemed debt to account 189 "Unamortized Loss on Reacquired Debt" or account 257 "Unamortized Gain on Reacquired Debt" as appropriate and amortizes this amount over the life of the new issue if refunded or over the remaining life of the original debt if not refunded.

Schedule Page: 256.2 Line No.: 27 Column: a

On February 15, 2002 the Company entered into a loan agreement with the South Carolina Transportation Infrastructure Bank which is an instrumentality of the State of South Carolina. The amount of $59,000,000 is non-interest bearing and payable in quarterly payments of $1.475 million each January 1, April 1, July 1 and October 1. This obligation was fully satisfied in 2014 and as of 12/31/2014, there was no balance outstanding related to this agreement.

Schedule Page: 256.2 Line No.: 28 Column: a

The Company has had no long-term borrowings against its revolving credit agreements. These agreements expire in October 2016 and October 2019. See also response to Item 6 on pages 108 and 109.

Schedule Page: 256.2 Line No.: 30 Column: a

In 2007, the Company was awarded the contract for the privatization of the natural gas distribution system at the Charleston Air Force Base. On September 1, 2007, ownership of the system transferred to the Company and the Company recorded assets totaling $424,844 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off this long-term debt through applied billing credits over a period of 20 years. As of 12/31/2014, $302,435 was outstanding related to this obligation.

Schedule Page: 256.2 Line No.: 31 Column: i

SCANA Holding Company (parent of SCE&G) allocates interest expense on commitment fees to its operating subsidiaries. During 2014, the portion allocated to SCE&G was $151,001.

Schedule Page: 256.2 Line No.: 32 Column: a

In February 2013, SCE&G entered into a contract to acquire Enriched Uranium Product (EUP) for the initial core load of the V.C. Summer Nuclear Station Unit No. 3 currently under construction. Under the provisions of the contract, SCE&G recorded $99.9 million within Account 224 - Other Long-Term Debt and $2.8 million within Account 226 - Unamortized Discount on Long-Term Debt.

Schedule Page: 256.3 Line No.: 2 Column: i

The interest expense of $6,556,721 included in account 430 "Interest on Debt to Associated Companies" is related to short-term debt and therefore is not included in this schedule.

Schedule Page: 256.3 Line No.: 4 Column: a

At 12/31/2014, the Company had authorization from the South Carolina Public Service Commission to issue up to $1.56 billion of First Mortgage Bonds. (State Commission Order Nos. 2010-660 and 2013-277.)

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	445,329,227
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized	152,493,286
6	Contributions in Aid of Construction	25,083,121
7	Inventory Capitalization under 263A	555,579
8	Other (see detail)	813,884
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	283,085,884
11	Total Net Book Income Tax (including Investment Tax Credit)	211,369,914
12	Book Expense - Nuclear Fuel	45,229,090
13	Other (see detail)	42,431,828
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	41,780,592
16	Deferred Fuel Costs	4,028,000
17	Unearned Revenue	15,981
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	490,380,607
21	Regulatory Asset, Net loss on interest rate derivatives	124,698,872
22	Repair Allowance Deduction	70,334,671
23	Domestic Production Activities Deduction	33,947,853
24	174 Deduction	25,000,000
25	Storm Damage Accrual	21,828,838
26	Other (see detail)	65,007,252
27	Federal Tax Net Income	329,369,148
28	Show Computation of Tax:	
29	Tax @ 35%	115,279,202
30	Research Credit	
31	Partnership Credits	-8,975,735
32	Adjustments for Prior Years	-67,293,715
33	Current Federal Income Tax Expense Recorded	39,009,752
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 8 Column: b

Pension Plan	$ 517,884
Recovery of Deferred Capacity	296,000
Total	$ 813,884

Schedule Page: 261 Line No.: 13 Column: b

Other Post Retirement Benefits	$ 9,818,299
Book Gain/Loss	7,558,375
Regulatory Asset-Unrecovered Plant	6,995,400
Nuclear Decommissioning Expense Accrual	6,089,763
Book Vehicle Depreciation Charged to Operations	2,546,549
Amortization of Losses on Reacquired Debt	2,020,515
Meals and Lobbying	1,920,473
Section 162m Limitation	1,860,256
Regulatory Asset Scrubber	1,061,940
Gas WNA Cap	741,056
Directors Endowment	530,111
Uncollectible Accounts	322,749
Pollution Control	282,658
Emission Allowances	245,941
VCS Costs	183,816
Regulatory Asset Customer Programs	116,013
All Other	137,914
Total	$ 42,431,828

Schedule Page: 261 Line No.: 26 Column: b

State Income Tax Deduction	$ 16,046,000
Long Term Disability	11,581,774
Deferred Nuclear Fuel Expenses	11,030,209
Regulatory Asset-Carrying Costs	5,819,647
Prepayment Acceleration	5,334,515
Demand Side Management	4,505,946
Grants	2,235,000
Non Cash Donation	1,949,051
Regulatory Asset Deferred Capacity	1,747,610
Injuries and Damages	1,225,236
Fukushima Compliance	1,087,926
Major Maintenance Programs	1,041,086
Early Retirement Programs	691,297
Environmental Remediation Costs	377,591
Long Term Pledges	334,364
Total	$ 65,007,252

Schedule Page: 261 Line No.: 33 Column: b

South Carolina Electric & Gas Company is a wholly owned subsidiary of SCANA Corporation and is included in the consolidated federal income tax return of SCANA Corporation. Taxes are allocated to members based on their contributions to the consolidated total. Current federal income taxes recorded in 2014 by each memeber of the consolidated group were as follows:

SCANA Corporation	($27,597,700)	
SCANA Services	(1,000,400)	
South Carolina Electric & Gas Company	37,720,152	*
South Carolina Fuel Company	1,289,600	*
Carolina Gas Transmission Corporation	4,957,000	
South Carolina Generating Company	795,868	
Public Service Company of North Carolina	90,613	
PSNC Blue Ridge Corporation	9,500	
PSNC Clean Energy Enterprises,Inc.	500	
PSNC Cardinal Pipeline Corporation	27,600	
SCANA Communications, Inc.	2,934,366	
SCANA Communications Holding, Inc.	208,808	
SCANA Energy Marketing, Inc.	18,335,999	
Servicecare, Inc.	(5,700)	
Total	$37,766,206	

*$39,009,752

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal:					
2	Income	52,956,411		39,009,752	168,210,331	76,244,168
3	FUTA	8,478		231,898	229,151	-2,221
4	FICA	586,422		30,162,357	29,779,185	-301,718
5	Other Miscellaneous		15,804	30,988	31,162	
6	SUBTOTAL	53,551,311	15,804	69,434,995	198,249,829	75,940,229
7						
8	State:					
9	Income	5,889,164		-6,738,343	5,631,010	6,480,189
10	License			14,498,007	14,498,007	
11	Vehicle License			199,277	199,277	
12	Electric Generation	501,246		6,949,914	6,931,199	
13	SUTA	15,914		543,605	538,203	-4,599
14	Other Miscellaneous					
15	SUBTOTAL	6,406,324		15,452,460	27,797,696	6,475,590
16						
17	Local:					
18	County Property	150,480,826	466,041	157,168,076	151,582,833	
19	Municipal Property	8,183,529		8,686,080	8,185,914	
20	SUBTOTAL	158,664,355	466,041	165,854,156	159,768,747	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	218,621,990	481,845	250,741,611	385,816,272	82,415,819

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		26,658,600			12,351,152	2
9,004		90,356			141,542	3
667,876		12,272,089			17,890,268	4
	15,978				30,988	5
676,880	15,978	39,021,045			30,413,950	6
						7
						8
		-7,572,800			834,457	9
		12,773,703			1,724,304	10
					199,277	11
519,961		6,949,914				12
16,717		186,987			356,618	13
						14
536,678		12,337,804			3,114,656	15
						16
						17
156,143,116	543,088	138,537,618			18,630,458	18
8,683,695		7,668,071			1,018,009	19
164,826,811	543,088	146,205,689			19,648,467	20
						21
						22
						23
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						39
						40
166,040,369	559,066	197,564,538			53,177,073	41

Schedule Page: 262 Line No.: 2 Column: f

Overpayment of taxes reclassified to account 143 - Other Accounts Receivable.

Schedule Page: 262 Line No.: 3 Column: f

Estimated payroll taxes in the amount of ($2,277,426) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2014. Those adjustments are combined with a total of $1,968,888 of payroll taxes related to at-risk incentive compensation actually paid in 2014 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($308,538).

Schedule Page: 262 Line No.: 4 Column: f

Estimated payroll taxes in the amount of ($2,277,426) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2014. Those adjustments are combined with a total of $1,968,888 of payroll taxes related to at-risk incentive compensation actually paid in 2014 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($308,538).

Schedule Page: 262 Line No.: 9 Column: f

Overpayment of taxes reclassified to account 143 - Other Accounts Receivable.

Schedule Page: 262 Line No.: 13 Column: f

Estimated payroll taxes in the amount of ($2,277,426) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2014. Those adjustments are combined with a total of $1,968,888 of payroll taxes related to at-risk incentive compensation actually paid in 2014 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($308,538).

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	344,466			411.4	65,824	
4	7%						
5	10%	19,044,753			411.4	1,779,207	
6							
7	See Footnote	6,194,581			411.4	443,369	
8	TOTAL	25,583,800				2,288,400	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility						
11	4%	35,854			411.4	5,260	
12	10%	749,621			411.4	52,403	
13	20%	15,104			411.4	906	
14	8%	995,621			411.4	54,231	
15	See Footnote	2,139,200			411.4	1,166,400	
16	Total Gas	3,935,400				1,279,200	
17							
18							
19							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
278,642	42 Years		3
			4
17,265,546	42 Years		5
			6
5,751,212	42 Years		7
23,295,400			8
			9
			10
30,594	47.5 Years		11
697,218	47.5 Years		12
14,198	47.5 Years		13
941,390	47.5 Years		14
972,800	See Footnote		15
2,656,200			16
			17
			18
			19
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			45
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			47
			48

Schedule Page: 266 Line No.: 7 Column: h

Account Subdivision - Electric Utility 20% and 8%

	20%	**8%**
Beginning Balance	$57,103	$6,137,478
Less: Allocations	4,229	439,140
Ending Balance	$52,874	$5,698,338

Schedule Page: 266 Line No.: 15 Column: h

State of South Carolina Economic Impact Zone Investment Tax Credit.

Effective November 2010, pursuant to authorization by the South Carolina Public Service Commission, the Company accelerated the amortization of these Investment Tax Credits over a five year period.

Schedule Page: 266 Line No.: 15 Column: i

State of South Carolina Economic Impact Zone Investment Tax Credit.

Effective November 2010, pursuant to authorization by the South Carolina Public Service Commission, the Company accelerated the amortization of these Investment Tax Credits over a five year period.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accrued Pension Liability - Early					
2	Retirement Incentive Programs &					
3	Other	11,673,376	Various	1,210,697	1,072,504	11,535,183
4	Accrued Liability -Incentive Plans	3,832,237	Various	24,088,613	24,649,205	4,392,829
5	Gas Environmental Remediation	20,152,051	182	79,752,691	78,927,182	19,326,542
6	Other Environmental Remediation	1,284,244	Various	5,704,258	5,585,225	1,165,211
7	Long-Term Disability	16,145,629	131	16,089,209	6,083,789	6,140,209
8	Accrued Liability - Director's					
9	Endowment Program	3,482,169	131/426.5	466,109	1,278,189	4,294,249
10	Life Insurance Premium Obligation	31,545	926	31,859	12,028	11,714
11	Santee River Basin Accord	1,401,663	131	179,326	28,786	1,251,123
12	Municipal Nonstandard Service Fund					
13	Matching Obligation	6,876,528	186	934,862		5,941,666
14	SRS Substation	2,094,171	456	96,284		1,997,887
15	Interconnection Study Deposits	2,800	234/456	3,552	216,352	215,600
16	New Nuclear Transmission Lines	270,000	131	90,000		180,000
17	CIAC Obligation				16,089,000	16,089,000
18	Noncontrolling Interest - SCFC	1,791,841	131		486,217	2,278,058
19	Other	765,280	Various	2,420,717	2,309,983	654,546
20						
21						
22						
23						
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45						
46						
47	TOTAL	69,803,534		131,068,177	136,738,460	75,473,817

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	8,649,325	1,859,700	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	8,649,325	1,859,700	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	8,649,325	1,859,700	
18	Classification of TOTAL			
19	Federal Income Tax	7,518,700	1,616,600	
20	State Income Tax	1,130,625	243,100	
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						10,509,025	4
							5
							6
							7
						10,509,025	8
							9
							10
							11
							12
							13
							14
							15
							16
						10,509,025	17
							18
						9,135,300	19
						1,373,725	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,255,128,673	201,990,600	111,204,358
3	Gas	133,162,735	11,976,500	4,098,735
4	Other - Non Operating	8,839,700		
5	TOTAL (Enter Total of lines 2 thru 4)	1,397,131,108	213,967,100	115,303,093
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,397,131,108	213,967,100	115,303,093
10	Classification of TOTAL			
11	Federal Income Tax	1,241,047,980	188,390,200	99,910,175
12	State Income Tax	156,083,128	25,576,900	15,392,918
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3	6,299,300	182.3	28,286,200	1,367,901,815	2
		182.3	779,700	182.3	1,004,000	141,264,800	3
29,900	29,000					8,840,600	4
29,900	29,000		7,079,000		29,290,200	1,518,007,215	5
							6
							7
							8
29,900	29,000		7,079,000		29,290,200	1,518,007,215	9
							10
25,900	27,600		5,974,800		25,369,500	1,348,921,005	11
4,000	1,400		1,104,200		3,920,700	169,086,210	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Asset Retirement Obligation	103,152,400	4,095,100	3,956,400
4	Employee Benefit Plan Costs	46,510,900	37,308,500	4,168,500
5	Deferred Fuel Costs	23,745,500	26,702,500	25,295,400
6	Prepayments	20,128,100	1,437,600	
7	Pension Plan Income	20,413,500	2,471,200	34,391,000
8	All Other	93,140,500	20,748,200	13,384,500
9	TOTAL Electric (Total of lines 3 thru 8)	307,090,900	92,763,100	81,195,800
10	Gas			
11	Employee Benefit Plan Costs	7,010,700	5,026,600	632,500
12	Asset Retirement Obligation	5,743,200	359,600	
13	Prepayments	2,802,700	626,400	23,500
14	Deferred Fuel Costs	2,066,100	4,236,500	4,102,800
15	Pension Plan Income	5,307,100	370,300	4,990,000
16	All Other	2,044,100	3,100	331,500
17	TOTAL Gas (Total of lines 11 thru 16)	24,973,900	10,622,500	10,080,300
18	Non Operating	52,289,700		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	384,354,500	103,385,600	91,276,100
20	Classification of TOTAL			
21	Federal Income Tax	332,223,300	85,651,400	80,469,700
22	State Income Tax	52,131,200	17,734,200	10,806,400
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						103,291,100	3
						79,650,900	4
						25,152,600	5
						21,565,700	6
						-11,506,300	7
						100,504,200	8
						318,658,200	9
							10
						11,404,800	11
						6,102,800	12
						3,405,600	13
						2,199,800	14
						687,400	15
						1,715,700	16
						25,516,100	17
6,820,700	1,087,100			219	281,690	58,304,990	18
6,820,700	1,087,100				281,690	402,479,290	19
							20
5,987,700	1,050,800				244,820	342,586,720	21
833,000	36,300				36,870	59,892,570	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Balance at End of Year
Unrecovered Plant Canadys	$54,949,400	$ -	$ 2,676,200	$ 52,273,200
Demand Side Management Costs	19,565,200	1,723,500	83,100	21,205,600
FIN 48 Reserve	2,973,600	12,015,500	2,241,900	12,747,200
Reacquired Debt	6,860,300	-	849,000	6,011,300
Deferred Capacity	1,822,900	668,600	55,700	2,435,800
VCS Costs	2,005,000	-	70,400	1,934,600
Grants	1,387,500	855,000	852,000	1,390,500
Fukushima Compliance	792,100	416,100	40,200	1,168,000
Recovery of Deferred Capacity	740,700	-	113,300	627,400
State Credits	1,660,500	4,703,600	6,364,100	-
All Other	383,300	365,900	38,600	710,600
Total	$93,140,500	$20,748,200	$13,384,500	$100,504,200

Schedule Page: 276 Line No.: 16 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Balance at End of Year
Reaquired Debt	$ 750,800	$ 3,000	$ -	$ 753,800
Gas WNA Cap	919,300	100	283,500	635,900
Regulatory Asset Customer Programs	374,000	-	48,000	326,000
Total	$ 2,044,100	$ 3,100	$ 331,500	$ 1,715,700

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Accumulated Deferred Income Tax Credits	17,072,699	190	1,548,800		15,523,899
2	Storm Damage Reserve	27,299,661	571/593	66,595,126	44,766,288	5,470,823
3	Nuclear Refueling Accrual	16,293,307	524/528	36,157,552	25,127,342	5,263,097
4	ARO Cost of Removal	135,611,929	108/119	135,611,929		
5	NOX Emission Allowance Proceeds	153,256			40	153,296
6	Interest Rate Derivatives (3/2009-6/2043)	180,896,037	176/427/421	118,178,717	24,610,403	87,327,723
7	Demand Side Management Carrying Costs	3,195,884	182.3	582,109	3,178,036	5,791,811
8	SO2 Emission Allowance Proceeds				438	438
9	Overcollected Electric Pension Expense		182.3	477,050	650,297	173,247
10						
11						
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41	TOTAL	380,522,773		359,151,283	98,332,844	119,704,334

Schedule Page: 278 Line No.: 2 Column: a

SCPSC Docket No. 95-1000-E
SCPSC Docket No. 2007-335-E
SCPSC Docket No. 2008-416-E
SCPSC Docket No. 2009-489-E
SCPSC Docket NO. 2012-218-E

Schedule Page: 278 Line No.: 3 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 278 Line No.: 4 Column: d

Current year activity reflects revision in treatment of certain cost of removal to eliminate the reclassification of such amounts from the accumulated provision for depreciation.

Schedule Page: 278 Line No.: 6 Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

In SCPSC Docket Nos. 2013-382-E and 2014-2-E, the SCPSC authorized the Company to utilize gains from the settlement of certain interest rate derivatives for the benefit of its customers through offsetting fuel costs. In SCPSC Docket No. 2014-44-E, the SCPSC authorized the Company to utilize a portion of deferred swap settlement gains to offset certain Net Lost Revenue amounts associated with the Company's Demand Side Management Programs. Such utilization is also included in current year account activity.

Schedule Page: 278 Line No.: 7 Column: a

SCPSC Docket No. 2013-50-E
SCPSC Docket No. 2013-208-E
SCPSC Docket No. 2014-44-E

Schedule Page: 278 Line No.: 9 Column: a

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2014-88-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,163,092,091	1,060,020,247
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	838,612,663	787,432,161
5	Large (or Ind.) (See Instr. 4)	464,102,667	427,969,327
6	(444) Public Street and Highway Lighting	14,131,899	13,145,419
7	(445) Other Sales to Public Authorities	49,418,059	46,336,899
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,529,357,379	2,334,904,053
11	(447) Sales for Resale	56,724,721	54,337,881
12	TOTAL Sales of Electricity	2,586,082,100	2,389,241,934
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,586,082,100	2,389,241,934
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,838,882	6,273,756
17	(451) Miscellaneous Service Revenues	3,802,376	3,826,834
18	(453) Sales of Water and Water Power	459,046	416,558
19	(454) Rent from Electric Property	18,074,094	18,836,159
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	5,970,713	4,863,692
22	(456.1) Revenues from Transmission of Electricity of Others	7,990,918	6,986,763
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	43,136,029	41,203,762
27	TOTAL Electric Operating Revenues	2,629,218,129	2,430,445,696

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
8,155,692	7,571,438	587,870	580,407	2
				3
7,385,143	7,218,945	91,954	90,770	4
6,233,593	5,999,795	753	740	5
71,710	69,319	708	650	6
528,377	511,593	3,386	3,381	7
				8
				9
22,374,515	21,371,090	684,671	675,948	10
958,427	955,488	5	5	11
23,332,942	22,326,578	684,676	675,953	12
				13
23,332,942	22,326,578	684,676	675,953	14

Line 12, column (b) includes $ 91,257,578 of unbilled revenues.

Line 12, column (d) includes 722,209 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 5 Column: d

Includes 3,337 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 5 Column: e

Includes 3,410 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 10 Column: b

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$ 971,774
Commercial	871,478
Industrial	931,042
Street Lighting	10,716
Other Public Authorities	64,637
	$2,849,647

Includes Unmetered Sales Revenue as follows:

Residential	$19,328,022
Commercial/Industrial	29,511,187
Street Lighting	12,993,793
Other Public Authorities	145,562
	$61,978,564

Schedule Page: 300 Line No.: 10 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($9,183,651)
Commercial	(9,219,043)
Industrial	(8,270,773)
Street Lighting	(100,331)
Other Public Authorities	(666,494)
	($27,440,292)

Includes Unmetered Sales Revenue as follows:

Residential	$19,306,898
Commercial/Industrial	28,934,448
Street Lighting	12,158,800
Other Public Authorities	142,533
	$60,542,679

Schedule Page: 300 Line No.: 10 Column: d

Includes Unmetered MWH Sales as follows:

Residential	78,931
Commercial/Industrial	136,855
Street Lighting	64,062
Other Public Authorities	1,066
	280,914

Schedule Page: 300 Line No.: 10 Column: e

Includes Unmetered MWH Sales as follows:

Residential	79,303
Commercial/Industrial	160,069
Street Lighting	61,896
Other Public Authorities	1,064
	302,332

Schedule Page: 300 Line No.: 10 Column: f

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	214,333
Commercial/Industrial	25,417
Street Lighting	879
Other Public Authorities	56
	240,685

Schedule Page: 300 Line No.: 10 Column: g

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	214,329
Commercial/Industrial	25,876
Street Lighting	894
Other Public Authorities	52
	241,151

Schedule Page: 300 Line No.: 17 Column: b

Includes $1,537,221 of reconnect and lighting disconnect charges.

Includes $2,024,507 of transmission maintenance fee revenue.

Includes $499,062 of returned check fees.

Account balance also includes debit activity of ($402,446) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 17 Column: c

Includes $1,658,667 of reconnect and lighting disconnect charges.

Includes $1,960,782 of transmission maintenance fee revenue.

Includes $465,126 of returned check fees.

Account balance also includes debit activity of ($415,697) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 21 Column: b

Includes $5,202,931 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $373,484 for sale of used oil.

Schedule Page: 300 Line No.: 21 Column: c

Includes $3,610,536 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $638,926 of Timber Sales Revenue.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales					
2	RATE					
3	1	349,494	47,392,863	21,373	16,352	0.1356
4	2	28,179	4,803,827	16,549	1,703	0.1705
5	5	1,220	170,684	80	15,250	0.1399
6	6	493,493	67,042,000	31,071	15,883	0.1359
7	7	360	41,680	9	40,000	0.1158
8	8	7,201,188	1,023,905,497	518,576	13,886	0.1422
9	M6N	464	64,199	39	11,897	0.1384
10	M5N	3	505	1	3,000	0.1683
11	M1N	305	41,117	15	20,333	0.1348
12	M8N	2,303	327,674	158	14,576	0.1423
13	Special (A)	78,683	19,302,045	214,333	367	0.2453
14	Total Residential	8,155,692	1,163,092,091	802,204	10,167	0.1426
15						
16	Commercial & Industrial Sales					
17	RATE					
18	3	7,909	906,351	127	62,276	0.1146
19	9	2,553,699	344,613,694	76,497	33,383	0.1349
20	10	3,565	709,347	2,039	1,748	0.1990
21	11	13,665	1,473,267	308	44,367	0.1078
22	12	162,110	18,586,912	3,726	43,508	0.1147
23	14	19,978	2,916,037	1,861	10,735	0.1460
24	16	46,507	6,098,730	2,740	16,973	0.1311
25	20	1,878,730	201,346,342	2,172	864,977	0.1072
26	21	383,056	37,360,333	545	702,855	0.0975
27	22	419,303	50,303,083	1,786	234,772	0.1200
28	23	4,316,373	332,636,461	124	34,809,460	0.0771
29	24	2,029,768	177,021,892	185	10,971,719	0.0872
30	27	419,357	30,107,450	7	59,908,143	0.0718
31	28	2,496	303,791	20	124,800	0.1217
32	29	3,965	562,431	560	7,080	0.1418
33	60	1,213,017	67,679,022	4	303,254,250	0.0558
34	T20	9,648	1,091,998	6	1,608,000	0.1132
35	Special (A)	135,590	28,998,189	24,857	5,455	0.2139
36	Total Commercial & Industrial	13,618,736	1,302,715,330	117,564	115,841	0.0957
37						
38						
39	Special (A) is included in					
40	respondent's other					
41	TOTAL Billed	21,652,306	2,438,099,801	0	0	0.1126
42	Total Unbilled Rev.(See Instr. 6)	722,209	91,257,578	0	0	0.1264
43	TOTAL	22,374,515	2,529,357,379	0	0	0.1130

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	published tariffs and counted					
2	on these lines per Instruct. 3					
3						
4						
5						
6	Public Street & Highway					
7	Lighting Sales					
8	Rate					
9	3	1,496	189,672	95	15,747	0.1268
10	9	2,287	428,754	539	4,243	0.1875
11	29	232	30,487	10	23,200	0.1314
12	Special (A)	67,695	13,482,986	1,246	54,330	0.1992
13	Total Public Street & Hwy Lights	71,710	14,131,899	1,890	37,942	0.1971
14						
15	Other Sales to Public Authorities					
16	RATE					
17	3	151,817	17,598,074	3,183	47,696	0.1159
18	9	761	120,766	93	8,183	0.1587
19	20	13,773	1,322,692	9	1,530,333	0.0960
20	21	2,721	252,877	3	907,000	0.0929
21	29	792	104,042	44	18,000	0.1314
22	65	69,013	5,502,813	21	3,286,333	0.0797
23	66	289,226	24,475,003	33	8,764,424	0.0846
24	Special (A)	274	41,792	12	22,833	0.1525
25	Total OPAs	528,377	49,418,059	3,398	155,496	0.0935
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	21,652,306	2,438,099,801	0	0	0.1126
42	Total Unbilled Rev.(See Instr. 6)	722,209	91,257,578	0	0	0.1264
43	TOTAL	22,374,515	2,529,357,379	0	0	0.1130

Schedule Page: 304 Line No.: 14 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$ 971,774
Commercial	871,478
Industrial	931,042
Street Lighting	10,716
Other Public Authorities	64,637
	$2,849,647

Schedule Page: 304 Line No.: 36 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$ 971,774
Commercial	871,478
Industrial	931,042
Street Lighting	10,716
Other Public Authorities	64,637
	$2,849,647

Schedule Page: 304.1 Line No.: 13 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$ 971,774
Commercial	871,478
Industrial	931,042
Street Lighting	10,716
Other Public Authorities	64,637
	$2,849,647

Schedule Page: 304.1 Line No.: 25 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$ 971,774
Commercial	871,478
Industrial	931,042
Street Lighting	10,716
Other Public Authorities	64,637
	$2,849,647

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Town of McCormick	RQ		3.8	3.8	3.8
2	City of Orangeburg	RQ		137.0	154.0	149.1
3	Town of Winnsboro	RQ		12.3	12.2	12.2
4	Cargill Power Markets, LLC	OS				
5	The Energy Authority, Inc.	OS				
6	Emissions Allow Sales - Revenue Contra					
7	Wholesale Fuel Over/Under Collection					
8	Adjustments					
9	Transmission Revenue included in					
10	Energy Charges Column (i).					
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
20,700	569,985	847,930		1,417,915	1
870,181	12,023,940	39,057,579	-2,322	51,079,197	2
64,706	1,175,610	2,779,981	396,647	4,352,238	3
450		21,850		21,850	4
2,390		157,450		157,450	5
			-40	-40	6
			-303,889	-303,889	7
					8
					9
					10
					11
					12
					13
					14
955,587	13,769,535	42,685,490	394,325	56,849,350	
2,840	0	179,300	-303,929	-124,629	
958,427	**13,769,535**	**42,864,790**	**90,396**	**56,724,721**	

Schedule Page: 310 Line No.: 1 Column: c

FERC Electric Tariff, Fourth Revised Volume No. 1

Schedule Page: 310 Line No.: 2 Column: c

FERC Electric Rate Schedule No. 60

Schedule Page: 310 Line No.: 2 Column: j

Orangeburg generation credits for January 2014.

Schedule Page: 310 Line No.: 3 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 3 Column: j

Network transmission and ancillary services charges for the Town of Winnsboro. The transmission reservation is held by SCE&G Power Marketing which is serving as the agent for the Town of Winnsboro. Transmission base revenue totals $350,575 and ancillary services revenue totals $46,072.

Schedule Page: 310 Line No.: 4 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 4 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 5 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 5 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 6 Column: j

Transfer of gain / loss on sale of emission allowances to account 254 for purchasing future emission allowances.

Schedule Page: 310 Line No.: 7 Column: j

Over/under collection of fuel relating to sales to wholesale customers.

Schedule Page: 310 Line No.: 8 Column: i

Subtotal non-RQ of $179,300 includes transmission revenue for OS service of $18,300. Transmission base revenue totals $17,203 and ancillary services revenue totals $1,097.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,161,090	2,743,994
5	(501) Fuel	354,576,791	327,682,689
6	(502) Steam Expenses	16,116,564	23,732,305
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,374,910	10,617,335
10	(506) Miscellaneous Steam Power Expenses	5,610,284	4,863,649
11	(507) Rents	9,977	17,160
12	(509) Allowances	280,940	630,573
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	384,130,556	370,287,705
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	79,209	422,919
16	(511) Maintenance of Structures	1,160,209	1,646,229
17	(512) Maintenance of Boiler Plant	13,050,710	11,446,285
18	(513) Maintenance of Electric Plant	11,863,967	11,745,211
19	(514) Maintenance of Miscellaneous Steam Plant	4,724,110	4,312,698
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	30,878,205	29,573,342
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	415,008,761	399,861,047
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	9,291,240	10,875,158
25	(518) Fuel	46,626,853	62,366,870
26	(519) Coolants and Water	2,790,759	2,129,426
27	(520) Steam Expenses	8,079,790	4,855,977
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,759,022	1,261,395
31	(524) Miscellaneous Nuclear Power Expenses	37,745,367	37,495,273
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	107,293,031	118,984,099
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-6,444,574	15,766,158
36	(529) Maintenance of Structures	3,944,397	2,433,899
37	(530) Maintenance of Reactor Plant Equipment	17,174,412	2,476,037
38	(531) Maintenance of Electric Plant	3,572,623	2,156,886
39	(532) Maintenance of Miscellaneous Nuclear Plant	17,763,933	9,268,012
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	36,010,791	32,100,992
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	143,303,822	151,085,091
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	790,193	684,140
45	(536) Water for Power		
46	(537) Hydraulic Expenses	1,380,176	1,298,361
47	(538) Electric Expenses	178,574	152,107
48	(539) Miscellaneous Hydraulic Power Generation Expenses	656,211	677,877
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	3,005,154	2,812,485
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	136,004	102,598
54	(542) Maintenance of Structures	162,777	59,702
55	(543) Maintenance of Reservoirs, Dams, and Waterways	905,926	518,202
56	(544) Maintenance of Electric Plant	2,520,808	2,928,739
57	(545) Maintenance of Miscellaneous Hydraulic Plant	129,992	109,338
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,855,507	3,718,579
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	6,860,661	6,531,064

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,041,855	1,075,547
63	(547) Fuel	247,487,163	207,735,329
64	(548) Generation Expenses	4,298,392	4,285,430
65	(549) Miscellaneous Other Power Generation Expenses	1,943,589	1,552,639
66	(550) Rents	2,473	
67	TOTAL Operation (Enter Total of lines 62 thru 66)	254,773,472	214,648,945
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	468,415	466,766
70	(552) Maintenance of Structures	542,199	561,344
71	(553) Maintenance of Generating and Electric Plant	11,977,720	11,743,209
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	749,383	418,540
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	13,737,717	13,189,859
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	268,511,189	227,838,804
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	311,058,580	270,958,797
77	(556) System Control and Load Dispatching	2,201,882	1,956,470
78	(557) Other Expenses	382,158	483,467
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	313,642,620	273,398,734
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,147,327,053	1,058,714,740
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	905,055	754,720
84			
85	(561.1) Load Dispatch-Reliability	1,264,086	1,159,932
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	876,821	745,511
87	(561.3) Load Dispatch-Transmission Service and Scheduling	211,643	212,760
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	99,185	74,649
90	(561.6) Transmission Service Studies	-244	-4,618
91	(561.7) Generation Interconnection Studies	19,809	1,475
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	395,129	381,189
94	(563) Overhead Lines Expenses	380,296	1,390,266
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,177,500	541,357
97	(566) Miscellaneous Transmission Expenses	4,779,166	3,186,342
98	(567) Rents	320,129	310,624
99	TOTAL Operation (Enter Total of lines 83 thru 98)	12,428,575	8,754,207
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	27,017	26,651
102	(569) Maintenance of Structures	21,837	27,571
103	(569.1) Maintenance of Computer Hardware	685	
104	(569.2) Maintenance of Computer Software	276,143	237,510
105	(569.3) Maintenance of Communication Equipment	19,423	20,850
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,005,563	2,108,630
108	(571) Maintenance of Overhead Lines	5,801,524	7,077,675
109	(572) Maintenance of Underground Lines	5,497	4,969
110	(573) Maintenance of Miscellaneous Transmission Plant	120,449	117,856
111	TOTAL Maintenance (Total of lines 101 thru 110)	9,278,138	9,621,712
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	21,706,713	18,375,919

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	872,900	779,109
135	(581) Load Dispatching	853,315	822,362
136	(582) Station Expenses	605,612	514,721
137	(583) Overhead Line Expenses	1,135,897	957,868
138	(584) Underground Line Expenses	239,055	232,277
139	(585) Street Lighting and Signal System Expenses	364,433	354,753
140	(586) Meter Expenses	1,203,304	1,102,566
141	(587) Customer Installations Expenses	10,056	2,396
142	(588) Miscellaneous Expenses	7,186,569	6,818,094
143	(589) Rents	2,194,151	2,153,924
144	TOTAL Operation (Enter Total of lines 134 thru 143)	14,665,292	13,738,070
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	335,207	349,530
147	(591) Maintenance of Structures	10,711	6,515
148	(592) Maintenance of Station Equipment	4,062,082	3,241,604
149	(593) Maintenance of Overhead Lines	23,352,456	20,570,036
150	(594) Maintenance of Underground Lines	2,913,368	2,881,636
151	(595) Maintenance of Line Transformers	264,794	236,236
152	(596) Maintenance of Street Lighting and Signal Systems	2,625,330	2,429,126
153	(597) Maintenance of Meters	222,295	242,053
154	(598) Maintenance of Miscellaneous Distribution Plant	3,017,972	2,928,070
155	TOTAL Maintenance (Total of lines 146 thru 154)	36,804,215	32,884,806
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	51,469,507	46,622,876
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,503,947	1,403,786
160	(902) Meter Reading Expenses	1,616,362	1,764,521
161	(903) Customer Records and Collection Expenses	36,424,169	34,971,822
162	(904) Uncollectible Accounts	7,009,696	6,185,902
163	(905) Miscellaneous Customer Accounts Expenses	2,246,450	2,411,333
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	48,800,624	46,737,364

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	330,730	380,289
168	(908) Customer Assistance Expenses	8,973,332	6,991,770
169	(909) Informational and Instructional Expenses	1,960	1,638
170	(910) Miscellaneous Customer Service and Informational Expenses	272,209	324,590
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	9,578,231	7,698,287
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	1,083	281
175	(912) Demonstrating and Selling Expenses	1,443,258	1,350,575
176	(913) Advertising Expenses	-23	293
177	(916) Miscellaneous Sales Expenses	192,080	274,206
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,636,398	1,625,355
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	55,094,303	49,262,065
182	(921) Office Supplies and Expenses	19,847,487	18,636,855
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	13,867,035	11,467,274
185	(924) Property Insurance	7,063,100	6,648,738
186	(925) Injuries and Damages	5,858,213	5,898,902
187	(926) Employee Pensions and Benefits	44,906,622	52,466,913
188	(927) Franchise Requirements	7,641	5,588
189	(928) Regulatory Commission Expenses	5,051,779	5,968,418
190	(929) (Less) Duplicate Charges-Cr.	9,365,973	11,077,471
191	(930.1) General Advertising Expenses	39,790	20,081
192	(930.2) Miscellaneous General Expenses	16,485,465	13,830,541
193	(931) Rents	4,117,652	4,710,607
194	TOTAL Operation (Enter Total of lines 181 thru 193)	162,973,114	157,838,511
195	Maintenance		
196	(935) Maintenance of General Plant	6,442,313	5,530,961
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	169,415,427	163,369,472
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,449,933,953	1,343,144,013

Schedule Page: 320 Line No.: 35 Column: b

In SCPSC Docket No. 2012-218-E, the SCPSC authorized the Company to establish a 5-cycle or 90 month recovery of nuclear outage costs for V.C. Summer Nuclear Station Unit 1. Accordingly, the Company is accruing $17.2 million annually with $13.9 million and $3.3 million being accrued to account 528 and 524, respectively. Differences between actual outage costs incurred and the accrued amounts are recognized as regulatory assets or liabilities as appropriate. During 2014, the Company reversed actual outage costs of $23.9 million from account 528 and applied such costs against the established regulatory liability. As a result, the Company has reported net credit activity for the year in account 528.

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Georgia Power (Calhoun Falls)	RQ	Schedule #793			
2	Newberry Electric Cooperative	RQ	10/3/1975,5/3/1976			
3	Santee Cooper(Charleston Naval Shipyd)	RQ	1/7/1997			
4	Santee Cooper (Kempson Bridge)	RQ	7/29/1996			
5	Columbia Energy LLC	OS	Tariff #1			
6	International Paper	OS	5/1/1984			
7	Misc Territorial Customers	OS	Rate -- PR1			
8	City of Columbia - Columbia Hydro	RQ	2/2002			
9	Southeastern Power Administration	RQ	1/01,12/02			
10	South Carolina Generating Company, Inc	RQ	Schedule #1		594	594
11	Calpine Energy Services, LP	OS	Tariff #1			
12	Cargill Power Markets, LLC	OS	Schedule #1			
13	Duke Energy Carolinas, LLC	OS	Tariff #5			
14	Exelon Generation Company, LLC	OS	Tariff #3			
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,606				208,697		208,697	1
73				14,118		14,118	2
16,377				723,023		723,023	3
1,147				119,897		119,897	4
6,509				347,622		347,622	5
8,727				475,332		475,332	6
665				47,596		47,596	7
40,022				2,719,004		2,719,004	8
49					69,538	69,538	9
3,702,495				231,518,596		231,518,596	10
24,420				1,694,055		1,694,055	11
80,434				3,464,507		3,464,507	12
600				26,700		26,700	13
14,437				625,436		625,436	14
4,940,712	87	1,634	13,992,677	298,077,141	-1,011,238	311,058,580	

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Rainbow Energy Marketing Corporation	OS	Tariff #1			
2	Southern Company Services, Inc.	OS	Tariff #4			
3	The Energy Authority, Inc.	OS	12/1/2004			
4	Duke Energy Progress, Inc.- Emergency	OS				
5	Duke Energy Carolinas, LLC-Emergency	OS				
6	SC Public Service Authority-Emergency	OS				
7	Southern Comp.Services, Inc.-Emergency	OS				
8	Calpine Energy Services, LP	IU	Tariff #1			
9	Columbia Energy LLC	IU	Tariff #1			
10	Southern Company Services, Inc.	IF	Tariff #4			
11	Santee Cooper	LF	1/7/1997	25		
12	Columbia Energy LLC	EX	Tariff #5			
13						
14	Adjustments					
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
30,328				1,599,280		1,599,280	1
28,258			13,290	1,581,161		1,594,451	2
142,525			88,863	10,374,323		10,463,186	3
3,362				2,351,817		2,351,817	4
6,330				2,506,846		2,506,846	5
520				244,634		244,634	6
1,084				1,491,532		1,491,532	7
194,625			3,426,500	10,561,788	156,000	14,144,288	8
314,651			3,432,000	11,185,355	432,853	15,050,208	9
254,294			3,539,904	11,596,364		15,136,268	10
63,174			3,492,120	2,716,270		6,208,390	11
	87	1,634		-116,812	2,833	-113,979	12
							13
					-1,672,462	-1,672,462	14
4,940,712	87	1,634	13,992,677	298,077,141	-1,011,238	311,058,580	

Schedule Page: 326 Line No.: 1 Column: c
Contract for electric service dated 06/20/1973.

Schedule Page: 326 Line No.: 2 Column: c
Contract for electric service dated 10/3/1975 and 05/3/1976.

Schedule Page: 326 Line No.: 3 Column: c
Contract for electric service dated 01/7/1997.

Schedule Page: 326 Line No.: 4 Column: c
Contract for electric service dated 07/29/1996.

Schedule Page: 326 Line No.: 5 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326 Line No.: 5 Column: c
Contract for Test and Excess Energy Purchase and Sale Agreement between South Carolina Electric & Gas Company and Columbia Energy LLC dated as of 1/17/2004.

Schedule Page: 326 Line No.: 6 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326 Line No.: 6 Column: c
Contract for electric service dated 5/1/1984.

Schedule Page: 326 Line No.: 7 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326 Line No.: 7 Column: c
Various agreements for purchased power from customers pursuant to the Company's PR-1 (Small Power Production, Cogeneration) Rate Schedule.

Schedule Page: 326 Line No.: 9 Column: c
Docket Nos. ER01-1043-000 and ER03-237-000.

Schedule Page: 326 Line No.: 9 Column: l
Barter arrangement for transmission ancillary services 1, 2, 5, and 6.

Schedule Page: 326 Line No.: 10 Column: a
Affiliated company.

Schedule Page: 326 Line No.: 10 Column: c
FERC Electric Rate Schedule No. 1, Schedule 8 Billing Format -- Cost of Service Tariff Docket Nos. ER85-204-007 and ER85-603-005.

Schedule Page: 326 Line No.: 11 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326 Line No.: 11 Column: c
Tariff No. 1, Docket No. ER14-2119.

Schedule Page: 326 Line No.: 12 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326 Line No.: 12 Column: c
FERC Electric Rate Schedule No. 1, Docket No. ER10-2712.

Schedule Page: 326 Line No.: 13 Column: b
OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement.

Schedule Page: 326 Line No.: 13 Column: c
Tariff No. 5, Docket No. ER12-2322.

Schedule Page: 326 Line No.: 14 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326 Line No.: 14 Column: c
FERC Electric Tariff Volume No. 3, Docket No. ER14-1625.

Schedule Page: 326.1 Line No.: 1 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326.1 Line No.: 1 Column: c
Tariff #1, Docket No. ER10-2778.

Schedule Page: 326.1 Line No.: 2 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326.1 Line No.: 2 Column: c
Tariff No. 4, Docket No. ER10-2881.

Schedule Page: 326.1 Line No.: 3 Column: b
OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute Inc.(EEI) Master Power Purchase Sale Agreement.

Schedule Page: 326.1 Line No.: 3 Column: c
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2004.

Schedule Page: 326.1 Line No.: 4 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326.1 Line No.: 4 Column: c
FERC Electric Rate Schedule No. 29.

Schedule Page: 326.1 Line No.: 5 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326.1 Line No.: 5 Column: c
FERC Electric Rate Schedule No. 42.

Schedule Page: 326.1 Line No.: 6 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326.1 Line No.: 6 Column: c
FERC Electric Rate Schedule No. 33.

Schedule Page: 326.1 Line No.: 7 Column: b
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff/schedule.

Schedule Page: 326.1 Line No.: 7 Column: c
FERC Electric Rate Schedule No. 30.

Schedule Page: 326.1 Line No.: 8 Column: b
IU - Service from designated generating units(s) with duration longer than the one year but less than five years.

Schedule Page: 326.1 Line No.: 8 Column: c
Tariff No. 1, Docket No. ER14-2119.

Schedule Page: 326.1 Line No.: 8 Column: l
Scheduling Charges

Schedule Page: 326.1 Line No.: 9 Column: b
IU - Service from designated generating units(s) with duration longer than the one year but less than five years.

Schedule Page: 326.1 Line No.: 9 Column: c
Tariff No. 1, Docket No. ER10-1892.

Schedule Page: 326.1 Line No.: 9 Column: l
Scheduling Charges

Schedule Page: 326.1 Line No.: 10 Column: b
IF - Firm service with duration longer than one year but less than five years. Earliest termination date is 12/31/2016.

Schedule Page: 326.1 Line No.: 10 Column: c
Tariff No. 4, Docket No. ER10-2881.

Schedule Page: 326.1 Line No.: 11 Column: a

Termination date is December 31, 2016 with evergreen provisions and requires a 4-year written notice by either party to terminate the agreement.

Schedule Page: 326.1 Line No.: 11 Column: c

Contract for electric service dated 1/7/1997.

Schedule Page: 326.1 Line No.: 12 Column: b

EX - Exchanges of electricity.

Schedule Page: 326.1 Line No.: 12 Column: c

Electric service provided under SCE&G's OATT Schedules 4 and 9.

Schedule Page: 326.1 Line No.: 12 Column: h

Over delivery of energy by Columbia Energy LLC.

Schedule Page: 326.1 Line No.: 12 Column: i

Under delivery of energy by Columbia Energy LLC.

Schedule Page: 326.1 Line No.: 12 Column: l

Columbia Energy LLC Generator Imbalance Calculation Credit -- This credit to Columbia Energy LLC results from a revision to imbalance calculation methods for prior periods under Schedule 9 - Generator Imbalance Service of SCE&G's Open Access Transmission Tariff (2007-2013).

Total NET Refund for 2007-2013 = $2,832.78
(Over Delivery = $3,672.38; Under Delivery = credit of $839.60)

Schedule Page: 326.1 Line No.: 14 Column: l

Reflects amortization of previously deferred purchase power of $1,808,371 per SCPSC Docket No. 2009-489-E.

Reflects the deferral of purchase power per SCPSC Docket No. 2009-489-E of($1,190,068).

Reflects the deferral of short term capacity purchases from The Energy Authority, Inc. and Southern Company Services, Inc. per SCPSC Docket Nos. 2008-230-E and 2012-218-E of ($102,153).

Reflects the deferral of purchase power from Southern Company Services, Inc. and Columbia Energy LLC (formerly known as Calpine Energy Services, LP) per SCPSC Docket No. 2013-276-E of($2,188,612).

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	South Carolina Electric & Gas Company	South Carolina Electric & Gas Co	South Carolina Electric & Gas Co	NF
2	South Carolina Electric & Gas Company	South Carolina Electric & Gas Co	South Carolina Electric & Gas Co	SFP
3	Calpine Energy Services, LP	Columbia Energy, LLC	Duke Energy Progress, LLC	NF
4	Calpine Energy Services, LP	Columbia Energy, LLC	Duke Energy Carolinas, LLC	NF
5	Southern Company Services, Inc.	Duke Energy Carolinas, LLC	Georgia Power Company	NF
6	Duke Energy Progress, LLC	Georgia Power Company	Duke Energy Progress, LLC	SFP
7	The Energy Authority, Inc.	Duke Energy Carolinas, LLC	SC Public Service Authority	NF
8	The Energy Authority, Inc.	Georgia Power Company	SC Public Service Authority	NF
9	Duke Energy Carolinas, LLC	Georgia Power Company	Duke Energy Progress, LLC	NF
10	NC Electric Membership Corp.	NC Electric Membership Corp.	Georgia Power Company	NF
11	Rainbow Energy Marketing Corp	Columbia Energy, LLC	Georgia Power Company	NF
12	SC Public Service Authority	SC Public Service Authority	SC Public Service Authority	OS
13	SC Public Service Authority	SC Public Service Authority	Various	FNO
14	Southeastern Power Administration	Southeastern Power Administration	Various	FNO
15	City of Orangeburg	South Carolina Electric & Gas Co	City of Orangeburg	FNO
16	Central Electric Power Co-op	SC Public Service Authority	Central Electric Power Co-op	FNO
17				
18				
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22				
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25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
T5.S8, S1, S2	SCEG	SOCO		3,191	3,126	1
T5.S7, S1, S2	SCEG	SOCO	45	209	204	2
T5.S8, S1, S2	SCEG	CPLE		339	332	3
T5.S8, S1, S2	SCEG	DUK		2,016	1,974	4
T5.S8, S1, S2	DUK	SOCO		756	740	5
T5.S7, S1, S2	SOCO	CPLE	162	2,254	2,208	6
T5.S8, S1, S2	DUK	SC		300	294	7
T5.S8, S1, S2	SOCO	SC		160	155	8
T5.S8, S1, S2	SOCO	CPLE		99	97	9
T5.S8, S1, S2	DUK	SOCO		62	60	10
T5.S8, S1, S2	SCEG	SOCO		160	156	11
49			146	68,875	66,869	12
T5, Attach H			539	234,003	227,188	13
T5, Attach H			216	34,735	33,522	14
T5, Attach H			1,657	896,138	870,036	15
T5, Attach H			71	27,773	27,227	16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			2,836	**1,271,070**	**1,234,188**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (I), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
22,130		1,346	23,476	1
5,245		313	5,558	2
2,499		149	2,648	3
18,211		1,033	19,244	4
2,990		267	3,257	5
18,884		1,124	20,008	6
2,186		130	2,316	7
1,256		72	1,328	8
354		24	378	9
245		14	259	10
1,004		54	1,058	11
75,000			75,000	12
1,468,746	272,868	81,129	1,822,743	13
605,371		69,538	674,909	14
4,532,524		597,012	5,129,536	15
198,265		10,935	209,200	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
6,954,910	**272,868**	**763,140**	**7,990,918**	

Schedule Page: 328 Line No.: 1 Column: h
Non-firm hourly billing demand of 3,595.
Schedule Page: 328 Line No.: 1 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 1 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 1 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 2 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 2 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 2 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 3 Column: h
Non-firm hourly billing demand of 343.
Schedule Page: 328 Line No.: 3 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 3 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 3 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 4 Column: h
Non-firm hourly billing demand of 2,390.
Schedule Page: 328 Line No.: 4 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 4 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 4 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 5 Column: h
Non-firm hourly billing demand of 757.
Schedule Page: 328 Line No.: 5 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 5 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 5 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 6 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 6 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 6 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 7 Column: h
Non-firm hourly billing demand of 300.
Schedule Page: 328 Line No.: 7 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 7 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 7 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 8 Column: h

Non-firm hourly billing demand of 167.

Schedule Page: 328 Line No.: 8 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 8 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 8 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 9 Column: h
Non-firm hourly billing demand of 102.

Schedule Page: 328 Line No.: 9 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 9 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 9 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 10 Column: h
Non-firm hourly billing demand of 62.

Schedule Page: 328 Line No.: 10 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 10 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 10 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 11 Column: h
Non-firm hourly billing demand of 164.

Schedule Page: 328 Line No.: 11 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 11 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 11 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 12 Column: e
Negotiated Contract pre-dating order 888 expiring December 31, 2014.

Schedule Page: 328 Line No.: 12 Column: h
Negotiated Contract pre-dating order 888 expiring December 31, 2014.

Schedule Page: 328 Line No.: 12 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 12 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 12 Column: k
Negotiated Contract pre-dating order 888 expiring December 31, 2014.

Schedule Page: 328 Line No.: 12 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 13 Column: e
Also includes Rate Schedules S1, S2 and S4 of Tariff.

Schedule Page: 328 Line No.: 13 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 13 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 13 Column: l
Charges for Ancillary Service 4 (Energy Imbalance). Of the $272,868, $2,570 is related to an out of period adjustment for December 2013.

Schedule Page: 328 Line No.: 13 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 13 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 14 Column: e
Also includes Rate Schedules S1, S2, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 14 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 14 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 14 Column: m
Sum of Ancillary Service 1, 2, 5 and 6 charges.

Schedule Page: 328 Line No.: 14 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 15 Column: e
Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 15 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 15 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 15 Column: m
Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 15 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 16 Column: e
Also includes Rate Schedules S1 and S2 of Tariff.

Schedule Page: 328 Line No.: 16 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 16 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 16 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 16 Column: n
Network transmission revenue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Carolinas	FNS	4,959	4,770	13,984	1,756	16,150	31,890
2	Southern Co Svcs, Inc	SFP	248,899		3,039,230		245,860	3,285,090
3	SCE&G	NF		3,080	22,130		1,347	23,477
4	SCE&G	SFP		204	5,245		312	5,557
5	Southern Co Svcs, Inc	NF	4,063		29,859		1,961	31,820
6	Santee Cooper	NF	194		1,073		173	1,246
7	Adjustments						-201,580	-201,580
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		258,115	8,054	3,111,521	1,756	64,223	3,177,500

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FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: f

Energy Imbalance associated with Chappells delivery point.

Schedule Page: 332 Line No.: 1 Column: g

Scheduling, System Control and Dispatch	$ 322
Reactive Supply and Voltage Control	1,946
Regulation and Frequency Response	370
Operating Reserve - Spinning	793
Operating Reserve - Supplement	793
Other - Direct Assignment Charges	11,926
Total	$ 16,150

Schedule Page: 332 Line No.: 2 Column: g

Scheduling, System Control and Dispatch	$ 96,836
Reactive Supply and Voltage Control	132,155
Other: Recovery of FERC Annual Charge Factor	16,345
Other: Recovery of Attachment K Charge Factor	524
Total	$ 245,860

Schedule Page: 332 Line No.: 3 Column: g

Scheduling, System Control and Dispatch	$ 407
Reactive Supply and Voltage Control	940
Total	$ 1,347

Schedule Page: 332 Line No.: 4 Column: g

Scheduling, System Control and Dispatch	$ 96
Reactive Supply and Voltage Control	216
Total	$ 312

Schedule Page: 332 Line No.: 5 Column: g

Scheduling, System Control and Dispatch	$ 718
Reactive Supply and Voltage Control	970
Other: Recovery of FERC Annual Charge Factor	265
Other: Recovery of Attachment K Charge Factor	8
Total	$ 1,961

Schedule Page: 332 Line No.: 6 Column: g

Scheduling, System Control and Dispatch	$ 49
Reactive Supply and Voltage Control	124
Total	$ 173

Schedule Page: 332 Line No.: 7 Column: g

Columbia Energy LLC Reactive Supply and Voltage Control (RSV) to SCE&G	$ 488,000
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services pursuant to SCPSC Docket No. 2013-276-E	(689,580)
Southern Company Services, Inc refund calculated on Transmission Service for 2013	(1)
PJM Settlement, Inc. prior period adjustments for 2011-2012 Balancing Operating Reserves	1
Total	$(201,580)

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	491,237
2	Nuclear Power Research Expenses	611,529
3	Other Experimental and General Research Expenses	930,737
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	187,157
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Other Business Expenses	33,639
7	Transportation and Other Power Operated Equipment	19,477
8	Travel excluding Meals	4,224
9	Meals	3,488
10	Computer Hardware and Software Maintenance	61,892
11	Utilities	15,054
12	Telephone Resource Usage	46,184
13	Directors Fees and Expenses	1,304,370
14	Outside Services	100,989
15	Computer Resource Usage, Software, Hardware and	
16	Network Services	204,340
17	Company Payroll	40,547
18	Aircraft Transportation	73,456
19	Depreciation, Amortization and Property Tax Charges	
20	billed from SCANA Services	12,174,861
21	Postage	3,170
22	Joint Ownership Shared Cost True Up	65,119
23	Research & Development Grant Amortization	100,000
24	Miscellaneous	13,995
25		
26		
27		
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46	TOTAL	16,485,465

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			5,394,178		5,394,178
2	Steam Production Plant	74,402,452				74,402,452
3	Nuclear Production Plant	21,318,701				21,318,701
4	Hydraulic Production Plant-Conventional	3,158,787				3,158,787
5	Hydraulic Production Plant-Pumped Storage	2,667,896				2,667,896
6	Other Production Plant	30,752,598				30,752,598
7	Transmission Plant	24,535,359				24,535,359
8	Distribution Plant	69,501,637				69,501,637
9	Regional Transmission and Market Operation					
10	General Plant	10,032,037				10,032,037
11	Common Plant-Electric	6,930,706		2,598,032		9,528,738
12	TOTAL	243,300,173		7,992,210		251,292,383

B. Basis for Amortization Charges

Electric Intangible Plant (Account 404) consists of the following:
Amortization of Saluda Hydro Project #516, Stevens Creek Project #2535, Neal Shoals Project #2315 and relicensing costs associated with V. C. Summer Nuclear Station. The charges were based on plant balances of Saluda - $793,257, Stevens Creek - $2,268,402 and Neal Shoals - $1,507,161. The associated costs of relicensing the V. C. Summer Nuclear Plant through 2042 is $8,564,832.

Amortization of a steam generator at a cogeneration facility over the contractual term of the facility. The amortization is based on a gross plant amount of $11,144,060.

Data processing software costs of $64,560,552 are being amortized over the expected life of the software application.

Common Plant - Electric (Account 404):
Amortization of data processing software of $124,733,868 over the expected life of the software application.

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production:						
13	Urquhart - 311	16,815	80.00	-30.00	2.85	R1.5	15.80
14	Urquhart - 312	21,298	40.00	-25.00	6.69	S0	13.70
15	Urquhart - 314	44,000	50.00	-25.00	4.53	R2	15.30
16	Urquhart - 315	9,480	55.00	-15.00	2.79	R3	15.50
17	Urquhart - 316	4,677	42.00	-5.00	4.74	R0.5	14.80
18	Total Urquhart	96,270					
19							
20	McMeekin - 311	20,834	80.00	-30.00	5.47	R1.5	18.70
21	McMeekin - 312	132,386	40.00	-25.00	4.79	S0	16.60
22	McMeekin - 314	38,286	50.00	-25.00	5.73	R2	17.20
23	McMeekin - 315	11,150	55.00	-15.00	3.11	R3	18.30
24	McMeekin - 316	4,887	42.00	-5.00	3.33	R0.5	17.10
25	Total McMeekin	207,543					
26							
27	Cope - 311	81,915	80.00	-30.00	3.49	R1.5	26.10
28	Cope - 312	330,468	40.00	-25.00	4.17	S0	21.80
29	Cope - 314	86,893	50.00	-25.00	3.48	R2	24.80
30	Cope - 315	23,827	55.00	-15.00	3.02	R3	26.10
31	Cope - 316	10,379	42.00	-5.00	3.31	R0.5	22.80
32	Total Cope	533,482					
33							
34	Jasper - 312	471	40.00	-25.00	4.42	S0	26.00
35	Jasper - 314	101,641	50.00	-25.00	4.08	R2	28.20
36	Jasper - 315	4,121	55.00	-15.00	3.43	R3	29.50
37	Jasper - 316	295	42.00	-5.00	3.86	R0.5	25.60
38	Total Jasper	106,528					
39							
40	Central Lab - 311	3,393	80.00	-30.00	4.68	R1.5	18.80
41	Central Lab - 315	59	55.00	-15.00	2.61	R3	18.30
42	Central Lab - 316	2,270	42.00	-5.00	5.28	R0.5	17.30
43	Total Central Lab	5,722					
44							
45	Wateree - 311	124,881	80.00	-30.00	3.26	R1.5	25.20
46	Wateree - 312	567,456	40.00	-25.00	4.31	S0	21.80
47	Wateree - 314	142,967	50.00	-25.00	3.98	R2	24.50
48	Wateree - 315	27,755	55.00	-15.00	1.57	R3	22.20
49	Wateree - 316	5,802	42.00	-5.00	3.22	R0.5	21.90
50	Total Wateree	868,861					

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13	Nuclear Production:						
14	V.C. Summer -321	277,812	80.00	-1.00	1.46	S0.5	30.10
15	V.C. Summer -322	475,250	50.00	-3.00	2.08	S1.5	26.10
16	V.C. Summer -323	97,859	50.00	-5.00	2.31	S1	26.50
17	V.C. Summer -324	101,501	45.00		1.77	S2.5	22.00
18	V.C. Summer -325	105,976	35.00	-2.00	3.25	L1.5	21.00
19	Total V.C. Summer	1,058,398					
20							
21	Hydro Production -						
22	Conventional:						
23	Neal Shoals - 331	740	100.00	-5.00	3.25	R2	16.20
24	Neal Shoals - 332	3,617	125.00	-5.00	1.09	R2.5	16.40
25	Neal Shoals - 333	2,833	80.00	-10.00	4.62	R2	16.00
26	Neal Shoals - 334	379	55.00	-5.00	4.88	O1	13.70
27	Neal Shoals - 335	263	60.00	-5.00	4.30	R1	15.40
28	Neal Shoals - 336	3	60.00		2.23	R4	16.20
29	Total Neal Shoals	7,835					
30							
31	Parr - 331	1,903	100.00	-5.00	6.33	R2	16.00
32	Parr - 332	4,273	125.00	-5.00	3.17	R2.5	16.40
33	Parr - 333	2,844	80.00	-10.00	2.66	R2	15.40
34	Parr - 334	1,859	55.00	-5.00	4.08	O1	14.80
35	Parr - 335	432	60.00	-5.00	4.08	R1	15.30
36	Parr - 336	124	60.00		2.51	R4	16.50
37	Total Parr	11,435					
38							
39	Stevens Ck - 331	2,881	100.00	-5.00	4.02	R2	16.20
40	Stevens Ck - 332	6,432	125.00	-5.00	4.19	R2.5	16.40
41	Stevens Ck - 333	2,462	80.00	-10.00	4.48	R2	15.50
42	Stevens Ck - 334	1,621	55.00	-5.00	4.01	O1	15.00
43	Stevens Ck - 335	1,003	60.00	-5.00	4.61	R1	15.50
44	Stevens Ck - 336	129	60.00		5.57	R4	16.50
45	Total Stevens Ck	14,528					
46							
47	Saluda - 331	7,665	100.00	-5.00	1.61	R2	47.10
48	Saluda - 332	21,776	125.00	-5.00	0.94	R2.5	47.10
49	Saluda - 332.5 -					0	
50	Backup Dam	332,846	125.00		0.43	R2.5	50.30

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Saluda - 333	9,968	80.00	-10.00	1.50	R2	41.60
13	Saluda - 334	1,556	55.00	-5.00	1.73	O1	36.80
14	Saluda - 335	1,754	60.00	-5.00	1.95	R1	41.10
15	Saluda - 336	234	60.00		1.22	R4	38.20
16	Total Saluda	375,799					
17							
18	Hydro Production-						
19	Pumped Storage:						
20	Fairfield - 331	36,207	100.00	-5.00	1.09	R2	58.10
21	Fairfield - 332	74,478	125.00	-5.00	1.00	R2.5	63.70
22	Fairfield - 333	67,430	80.00	-10.00	1.69	R2	54.20
23	Fairfield - 334	15,216	55.00	-5.00	1.98	O1	41.70
24	Fairfield - 335	6,190	60.00	-5.00	1.85	R1	43.30
25	Fairfield - 336	1,328	60.00		1.77	R4	30.30
26	Total Fairfield	200,849					
27							
28	Other Production - Gas						
29	Turbine Units:						
30	Hardeeville - 341	58	40.00		1.58	S0.5	9.30
31	Hardeeville - 342	534	30.00	-15.00	10.66	S2	9.00
32	Hardeeville - 343	799	25.00	-5.00	7.79	S2.5	9.00
33	Hardeeville - 344	1,863	60.00	-5.00	1.63	S2	8.70
34	Hardeeville - 345	283	40.00	-10.00	2.50	S1.5	8.50
35	Hardeeville - 346	74	35.00		0.34	R2.5	8.60
36	Total Hardeeville	3,611					
37							
38	Coit - 341	182	40.00		5.41	S0.5	9.20
39	Coit - 342	552	30.00	-15.00	1.52	S2	8.30
40	Coit - 343	1,126	25.00	-5.00	3.55	S2.5	8.60
41	Coit - 344	3,500	60.00	-5.00	0.54	S2	9.00
42	Coit - 345	630	40.00	-10.00	10.31	S1.5	9.40
43	Coit - 346	162	35.00		6.25	R2.5	9.30
44	Total Coit	6,152					
45							
46	Parr - 341	877	40.00		5.81	S0.5	12.70
47	Parr - 342	581	30.00	-15.00	2.77	S2	8.30
48	Parr - 343	3,672	25.00	-5.00	7.53	S2.5	10.80
49	Parr - 344	3,096	60.00	-5.00	1.20	S2	12.70
50	Parr - 345	1,096	40.00	-10.00	7.14	S1.5	13.20

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Parr - 346	196	35.00		4.25	R2.5	12.10
13	Total Parr	9,518					
14							
15	Bushy Park - 341	596	40.00		9.30	S0.5	12.90
16	Bushy Park - 342	159	30.00	-15.00	4.67	S2	12.50
17	Bushy Park - 343	6,345	25.00	-5.00	4.55	S2.5	11.60
18	Bushy Park - 344	77	60.00	-5.00	3.29	S2	13.40
19	Bushy Park - 345	295	40.00	-10.00	6.63	S1.5	13.10
20	Bushy Park - 346	117	35.00		7.80	R2.5	13.20
21	Total Bushy Park	7,589					
22							
23	Hagood - 341	3,535	40.00		2.78	S0.5	14.30
24	Hagood - 342	808	30.00	-15.00	3.39	S2	12.00
25	Hagood - 343	24,297	25.00	-5.00	4.11	S2.5	9.10
26	Hagood - 344	6,036	60.00	-5.00	2.54	S2	16.00
27	Hagood - 345	2,441	40.00	-10.00	3.11	S1.5	14.50
28	Hagood - 346	345	35.00		7.30	R2.5	15.70
29	Total Hagood	37,462					
30							
31	Jasper - 341	28,138	40.00		3.56	S0.5	25.80
32	Jasper - 342	6	30.00	-15.00	4.38	S2	25.60
33	Jasper - 343	306,773	25.00	-5.00	4.03	S2.5	20.30
34	Jasper - 344	32,741	60.00	-5.00	3.19	S2	29.80
35	Jasper - 345	26,239	40.00	-10.00	3.49	S1.5	27.00
36	Jasper - 346	486	35.00		5.57	R2.5	26.60
37	Total Jasper	394,383					
38							
39	Urq 1 & 2 - 341	1,090	40.00		3.80	S0.5	24.90
40	Urq 1 & 2 - 342	197	30.00	-15.00	4.11	S2	18.00
41	Urq 1 & 2 - 343	633	25.00	-5.00	5.47	S2.5	12.90
42	Urq 1 & 2 - 344	3,412	60.00	-5.00	1.40	S2	20.90
43	Urq 1 & 2 - 345	124	40.00	-10.00	3.68	S1.5	21.00
44	Urq 1 & 2 - 346	88	35.00		4.28	R2.5	22.50
45	Total Urq 1 & 2	5,544					
46							
47	Urq 3 - 341	354	40.00		4.87	S0.5	10.90
48	Urq 3 - 342	8	30.00	-15.00	8.94	S2	11.30
49	Urq 3 - 343	215	25.00	-5.00	4.09	S2.5	18.40
50	Urq 3 - 344	1,633	60.00	-5.00	0.28	S2	10.60

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Urq 3 - 345	56	40.00	-10.00	5.13	S1.5	11.30
13	Total Urq 3	2,266					
14							
15	Urq 4 - 341	316	40.00		2.27	S0.5	15.10
16	Urq 4 - 342	959	30.00	-15.00	1.63	S2	14.50
17	Urq 4 - 343	2,445	25.00	-5.00	5.10	S2.5	14.70
18	Urq 4 - 344	19,799	60.00	-5.00	3.92	S2	16.40
19	Urq 4 - 345	445	40.00	-10.00	5.58	S1.5	16.10
20	Urq 4 - 346	44	35.00		5.14	R2.5	15.80
21	Total Urq 4	24,008					
22							
23	Urq 5 & 6 - 341	4,618	40.00		3.06	S0.5	24.00
24	Urq 5 & 6 - 342	3,609	30.00	-15.00	3.66	S2	21.70
25	Urq 5 & 6 - 343	230,543	25.00	-5.00	4.09	S2.5	18.40
26	Urq 5 & 6 - 344	13,383	60.00	-5.00	3.44	S2	27.80
27	Urq 5 & 6 - 345	12,795	40.00	-10.00	3.22	S1.5	25.00
28	Urq 5 & 6 - 346	136	35.00		3.62	R2.5	24.70
29	Total Urq 5 & 6	265,084					
30							
31	Boeing Solar - 341	117	20.00		5.00	SQ	
32	Boeing Solar - 344	7,031	20.00		5.00	SQ	
33	Boeing Solar - 345	2,197	20.00		5.00	SQ	
34	Boeing Solar - 346	18	20.00		5.00	SQ	
35	Total Boeing Solar	9,363					
36							
37	Hagood ICT U5 341	350	40.00		4.06	S0.5	
38	Hagood ICT U5 342	337	30.00	-15.00	4.46	S2	
39	Hagood ICT U5 343	4,993	25.00	-5.00	4.65	S2.5	
40	Hagood ICT U5 344		60.00	-5.00	3.02	S2	
41	Hagood ICT U5 345	2,131	40.00	-10.00	3.76	S1.5	
42	Hagood ICT U5 346		35.00		4.02	R2.5	
43	Total Hagood ICT U5	7,811					
44							
45	Hagood ICT U6 341	687	40.00		4.06	S0.5	
46	Hagood ICT U6 342	419	30.00	-15.00	4.46	S2	
47	Hagood ICT U6 343	5,517	25.00	-5.00	4.65	S2.5	
48	Hagood ICT U6 344	4	60.00	-5.00	3.02	S2	
49	Hagood ICT U6 345	3,273	40.00	-10.00	3.76	S1.5	
50	Hagood ICT U6 346	22	35.00		4.02	R2.5	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Total Hagood ICT U6	9,922					
13	Transmission:						
14	Nuclear - 352	605	65.00	-5.00	1.34	R2.5	29.60
15	Other - 352	3,473	65.00	-5.00	1.60	R2.5	56.20
16	Parr - 352	142	60.00	-20.00	3.08	S0.5	26.50
17	Saluda - 352	431	60.00	-20.00	2.46	S0.5	33.80
18	Stevens Creek - 352	38	60.00	-20.00	4.22	S0.5	22.60
19	Nuclear - 353	17,778	60.00	-20.00	2.00	S0.5	27.10
20	Parr - 353	375	60.00	-20.00	3.08	S0.5	26.50
21	Fairfield - 353	1,150	60.00	-20.00	1.19	S0.5	49.40
22	Saluda - 353	8,096	60.00	-20.00	2.46	S0.5	33.80
23	Stevens Ck - 353	4,643	60.00	-20.00	4.22	S0.5	22.60
24	Neal Shoals - 353	27	60.00	-20.00	1.01	S0.5	19.70
25	Nuclear Step-up - 353	13,746	60.00	-20.00	1.84	R3	28.90
26	Parr Step-up - 353	397	60.00	-20.00	2.60	R3	25.40
27	Fairfield Step-up 353	7,699	60.00	-20.00	1.62	R3	37.70
28	Saluda Step-up - 353	595	60.00	-20.00	2.11	R3	24.70
29	Wateree Step-up - 353	5,571	60.00	-20.00	3.04	R3	27.90
30	McMeekin Step-up - 353	819	60.00	-20.00	2.88	R3	18.80
31	Urq Steam Step-up-353	1,366	60.00	-20.00	2.84	R3	14.30
32	Williams Step-353	1,809	60.00	-20.00	2.77	R3	32.50
33	Cope Step-up - 353	6,020	60.00	-20.00	2.12	R3	43.20
34	Williams GT - 353	8,351	60.00	-20.00	2.56	R3	14.90
35	Jasper Step-up - 353	19,101	60.00	-20.00	2.20	R3	49.00
36	Burton Step-up - 353		60.00	-20.00	5.69	R3	3.40
37	Hardeeville Step-up353	118	60.00	-20.00	1.46	R3	23.60
38	Coit Step-up - 353	118	60.00	-20.00	3.96	R3	7.20
39	Hagood Step-up - 353	2,598	60.00	-20.00	1.53	R3	36.50
40	Stevens Crk Step-up353	404	60.00	-20.00	1.91	R3	37.20
41	Urq GT Step-up - 353	4,005	60.00	-20.00	9.77	R3	6.30
42	Bsy Park GT Step-up353	150	60.00	-20.00	2.56	R3	14.90
43	Station Equip - 353	324,058	60.00	-20.00	1.82	S0.5	48.80
44	Station Equip -						
45	CIPV5 - 353	4,347	60.00	-20.00	1.82	S0.5	48.80
46	Station Equip -					0	
47	Leasehold - 353.8	1,463	20.00		7.13	SQ	12.00
48	354	5,413	65.00	-25.00	1.40	R4.0	32.40
49	Neal Shoals - 354	1	60.00	-20.00	1.01	S0.5	19.70
50	355	318,820	53.00	-75.00	3.52	R2.5	40.10

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Neal Shoals - 355	21	60.00	-20.00	1.01	S0.5	19.70
13	355.8	2,080	20.00		5.77	SQ	10.50
14	356.1	183,880	60.00	-35.00	2.23	S2	44.70
15	356.2	2,894	60.00	-35.00	2.24	S2	50.10
16	356.8	1,089	20.00		4.91	SQ	10.20
17	357	20,725	55.00		1.79	R4.0	47.10
18	358	55,525	50.00		1.89	R3	40.90
19	359	74	55.00		1.77	S3	49.60
20	Total Transmission	1,030,015					
21	Distribution Plant:						
22	361	4,844	65.00	-5.00	1.67	R2.5	54.30
23	361.8	67	20.00		5.62	SQ	10.50
24	362	362,138	60.00	-10.00	2.01	S0.5	47.90
25	362.8	3,444	20.00		5.46	SQ	15.90
26	364	419,375	44.00	-25.00	2.68	R1.5	34.90
27	365	458,625	55.00	-20.00	1.80	R2	44.40
28	URD - 366	131,917	43.00	-10.00	2.43	R3	32.70
29	Network - 366	7,663	43.00	-10.00	2.43	R3	32.70
30	URD - 367	398,076	45.00	-10.00	2.13	S0.5	36.90
31	Network - 367	10,202	45.00	-10.00	2.13	S0.5	36.90
32	368	442,674	44.00	-10.00	2.13	R2	33.90
33	O/H - 369	101,328	60.00	-70.00	2.68	R3	43.60
34	U/G - 369	165,172	65.00	-30.00	1.78	R3	54.60
35	370	129,612	44.00	-3.00	2.02	R1	37.50
36	370.3	52,699	15.00		7.65	S2.5	12.40
37	373	279,824	33.00	-20.00	3.60	S1	24.70
38	Total Distribution	2,967,660					
39							
40	General Plant:						
41	3901	136,250	37.00	-5.00	2.64	S0.5	33.10
42	3902	10,044	25.00	-5.00	4.01	S2	15.40
43	3908	145	20.00		5.82	SQ	8.10
44	3909		20.00		8.88	SQ	4.50
45	3911	7,986	20.00		8.08	SQ	8.50
46	3912	1,388	5.00		17.40	SQ	2.80
47	3913	317	20.00		4.20	SQ	9.30
48	3919		20.00		18.96	SQ	2.50
49	393	270	25.00		2.71	SQ	12.30
50	3941	471	20.00		3.35	SQ	12.80

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	3942	2,452	20.00		9.19	SQ	7.10
13	3943	268	20.00		2.09	SQ	15.30
14	3944	284	20.00		0.66	SQ	15.50
15	3951	1,650	20.00		10.77	SQ	5.40
16	3952	420	20.00		4.81	SQ	8.30
17	3953	4,006	20.00		5.10	SQ	10.70
18	397	9,478	8.00		40.15	SQ	2.20
19	398	5,844	20.00		9.46	SQ	8.50
20	Total General Plant	181,273					
21							
22							
23							
24							
25							
26							
27							
28							
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50							

Schedule Page: 336 Line No.: 12 Column: a

Method of Determination of Depreciation Charges:

The Annual Provisions for Depreciation of Property, with the exception of major construction, are based on straight line rates applied to the prior month ending plant balances. The Annual Provision for Depreciation of major construction projects, if any, are computed based on the number of days that the plant was in service.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	State assessment for the support of the				
2	Public Service Commission of South				
3	Carolina (SCPSC) and annual charges assessed				
4	by the Federal Energy Regulatory Commission	4,553,493		4,553,493	
5					
6	Miscellanous expenses related to proceedings				
7	before the SCPSC		60,015	60,015	
8					
9	Company labor, legal, consulting and				
10	miscellaneous expenses related to proceedings				
11	before the FERC.		280,891	280,891	
12					
13	Incremental Company Expenses related to Docket				
14	No. 2009-489-E, Application for Increases and				
15	Adjustments in Electric Rate Schedules and				
16	Tariffs, before the SCPSC. Amortization				
17	period July 2010-July 2015		45,382	45,382	69,963
18					
19	Deferred Incremental Company expenses				
20	related to Docket No. 2012-218-E,				
21	Application for Increases and Adjustments in				
22	Electric Rate Schedules and Tariffs, before				
23	the SCPSC. Amortization period of				
24	January 2013 - December 2015.		54,860	54,860	109,721
25					
26	Company labor, legal and miscellaneous				
27	expenses related to Dockets associated with				
28	Revisions and Updates for the Construction and				
29	Operation of a Nuclear Facility in				
30	Jenkinsville, SC, related to proceedings				
31	before the SCPSC.		32,845	32,845	
32					
33	Company labor, legal and miscellaneous				
34	expenses associated with the Distributed				
35	Energy Resources Program Act before the				
36	SCPSC Docket No. 2015-54-E		24,293	24,293	
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,553,493	498,286	5,051,779	179,684

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
Electric	928	4,553,493					4
							5
							6
Electric	928	60,015					7
							8
							9
							10
Electric	928	280,891					11
							12
							13
							14
							15
							16
Electric				928	45,382	24,582	17
							18
							19
							20
							21
							22
							23
Electric				928	54,860	54,860	24
							25
							26
							27
							28
							29
							30
Electric	928	32,845					31
							32
							33
							34
							35
Electric	928	24,293					36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		4,951,537			100,242	79,442	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed Internally	
2	(1) Generation	EPRI Coordination
3		Technology Transfer
4	(2) Transmission	EPRI Coordination
5		Technology Transfer
6	(3) Distribution	EPRI Coordination
7		Technology Transfer
8	(4) Other	
9	Power Quality	EPRI Coordination
10	Total Internally	
11	B. Electric R,D and D Performed Externally	
12	(1) Research Support to EPRI	
13	Fossil Steam Plants and Combustion	
14	Turbines - Programs	
15		Boiler and Turbine Steam and Cycle Chemistry
16		Combined Cycle HRSG and Balance of Plant
17		Generation Maintenance Applications Center
18		Air Toxics Health and Risk Assessment
19		Coal Combustion Products - Envrionmental Issues
20		Air Quality Assessment of Ozone, Particulate Matter, Visibility and
21		Deposition
22		Fish Protection at Steam Electric Power Plants
23		Effluent Guidelines and Water Quality Management
24		Power Plant Multimedia Toxics Characterization
25	Nuclear Power - Programs	
26		Nuclear Power
27		Steam Turbines, Generators and Balance-of-Plant
28	Transmission and Substation - Programs	
29		Compression Connector Managment
30		Lightning Performance of Transmission Lines and Surge Arresters
31		Transmission Line Design Tools
32		Overhead Line Design and Research
33		Ratings for Overhead Lines
34		High Temperature Operation of Overhead Lines
35		Cable Dynamic Rating and Increased Power Flow Guidebook
36		Knowledge Capture & Tech Transfer Coordination
37		Other Substation Equip: Arrestors, External Insulation & Equip. Ratings
38		SF6 Environmental Management

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
97,785		Various	97,785		2
271		Various	271		3
11,719		Various	11,719		4
8,182		Various	8,182		5
16,200		Various	16,200		6
15,379		Various	15,379		7
					8
2,624		Various	2,624		9
152,160			152,160		10
					11
					12
					13
					14
	33,632	930.2	33,632		15
	77,683	930.2	77,683		16
	16,494	930.2	16,494		17
	70,988	930.2	70,988		18
	61,292	930.2	61,292		19
					20
	78,137	930.2	78,137		21
	69,032	930.2	69,032		22
	64,738	930.2	64,738		23
	77,577	930.2	77,577		24
					25
	611,529	930.2	611,529		26
	55,455	517	55,455		27
					28
	8,493	930.2	8,493		29
	19,636	930.2	19,636		30
	15,780	930.2	15,780		31
	12,624	930.2	12,624		32
	12,526	930.2	12,526		33
	14,315	930.2	14,315		34
	20,996	930.2	20,996		35
	8,398	930.2	8,398		36
	10,872	930.2	10,872		37
	10,096	930.2	10,096		38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1		
2	Distribution - Programs	
3		Modeling and Simulation of Renewables on Distribution
4		Technology Transfer and Industry Coordination
5		Distribution Inspection, Maintenance and Asset Planning
6		Tech Transfer and Industry Coordination
7		
8	Cyber Security - Programs	Cyber Security and Privacy Technology Transfer and Industry Collaboration
9		
10	Fossil Steam Plants and Combustion Turbines -	
11	Supplemental Projects	Power Plant Parameter Derivation (PPPD) User Group
12		
13	Nuclear - Supplemental Projects	
14		WRTC - Welding & Repair Technology Center
15		SGMP - Steam Generator Management Program
16		MRP - Pressurized Water Reactor Materials Reliability Program
17		FRP - Fuel Reliability Program (QA)
18		Fuel Works / Cask Loader Users Group
19		NDE - Nondestructive Evaluation Applications and Technology (QA)
20		PDI - Performance Demonstration Training and Qualification (QA)
21		NMAC - Nuclear Maintenance Application Center
22		Cable Program
23		HXPUG - Heat Exchanger Performance Users Group
24		Standardized Task Evaluations for Portable Qualifications (STE)
25		SWAP - Service Water Assistance Program
26		Submergence Qualification for Medium-Voltage Cable (QA)
27		CHECWORKS Users Group (CHUG)
28		BPIG - Buried Pipe Integrity Group
29		Phoenix Technology Development (QA)
30		PRA Documentation Assistant
31		GOTHIC Advisory Group (QA)
32		HRA/PRA Tool User Group (QA)
33		Risk and Reliability User Group
34		SMART chemWORKS User Group - Maintenance and Support
35		Advanced Nuclear Technology (ANT) New Plant Deployment
36		MAAP 4 Support (QA)
37		SQURTS – Seismic Qualification Reporting and Testing Standardization (QA)
38		SCE&G Development and Analysis of an Open-House Detection Scheme

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
	24,581	930.2	24,581		3
	16,387	930.2	16,387		4
	23,419	930.2	23,419		5
	11,425	930.2	11,425		6
					7
	19,775	930.2	19,775		8
					9
					10
	3,689	921	3,689		11
					12
					13
	9,826	524	9,826		14
	68,833	524	68,833		15
	6,117	524	6,117		16
	107,838	524	107,838		17
	12,000	107	12,000		18
	38,667	524	38,667		19
	1,667	524	1,667		20
	11,833	524	11,833		21
	2,333	524	2,333		22
	2,000	524	2,000		23
	9,029	524	9,029		24
	3,333	524	3,333		25
	10,000	524	10,000		26
	8,000	524	8,000		27
	10,000	524	10,000		28
	40,000	524	40,000		29
	6,667	524	6,667		30
	8,000	524	8,000		31
	6,667	524	6,667		32
	12,000	524	12,000		33
	21,000	524	21,000		34
	151,250	107	151,250		35
	8,667	107	8,667		36
	20,000	107	20,000		37
	50,000	107	50,000		38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1		
2	Transmission - Projects	
3		Power Quality Consulting Services
4		
5	Distribution - Projects	Power Quality Consulting Services
6		PQI Data Integration
7		
8	(2) Research Support to Clemson Univ. Electric	
9	Power Research Association	
10	(3) Research Support to National Electric	
11	Energy Testing and Research Applications	
12	Center	
13	(4) Research Support to Southeast Coastal	
14	Wind Coalition	
15	(5) Research Support to South Carolina	
16	Research Foundation	
17	(6) Research Support to Others:	
18	Marketing Research	
19		
20		
21		
22		
23	Total Externally	
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
	8,474	930.2	8,474		3
					4
	8,473	930.2	8,473		5
	1,260	908	1,260		6
					7
					8
	30,000	930.2	30,000		9
					10
					11
	95,000	930.2	95,000		12
					13
	5,000	921	5,000		14
					15
	60,000	921, 426	60,000		16
					17
	9,894	930.2	9,894		18
					19
					20
					21
					22
	2,293,397		2,293,397		23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	46,087,971		
4	Transmission	5,163,534		
5	Regional Market			
6	Distribution	5,684,931		
7	Customer Accounts	19,302,692		
8	Customer Service and Informational	2,638,672		
9	Sales	1,202,938		
10	Administrative and General	30,736,886		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	110,817,624		
12	Maintenance			
13	Production	26,461,735		
14	Transmission	2,370,545		
15	Regional Market			
16	Distribution	11,705,651		
17	Administrative and General	1,560,690		
18	TOTAL Maintenance (Total of lines 13 thru 17)	42,098,621		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	72,549,706		
21	Transmission (Enter Total of lines 4 and 14)	7,534,079		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	17,390,582		
24	Customer Accounts (Transcribe from line 7)	19,302,692		
25	Customer Service and Informational (Transcribe from line 8)	2,638,672		
26	Sales (Transcribe from line 9)	1,202,938		
27	Administrative and General (Enter Total of lines 10 and 17)	32,297,576		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	152,916,245	18,499,762	171,416,007
29	Gas			
30	Operation			
31	Production-Manufactured Gas	140,189		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	10,132,338		
37	Customer Accounts	4,298,351		
38	Customer Service and Informational	772,280		
39	Sales	2,737,699		
40	Administrative and General	5,308,346		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	23,389,203		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	3,312		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,492,210		
49	Administrative and General	214,292		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,709,814		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	140,189		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)	3,312		
57	Distribution (Lines 36 and 48)	13,624,548		
58	Customer Accounts (Line 37)	4,298,351		
59	Customer Service and Informational (Line 38)	772,280		
60	Sales (Line 39)	2,737,699		
61	Administrative and General (Lines 40 and 49)	5,522,638		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	27,099,017	3,354,764	30,453,781
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	180,015,262	21,854,526	201,869,788
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	68,357,330	6,468,403	74,825,733
69	Gas Plant	5,603,990	317,082	5,921,072
70	Other (provide details in footnote):		1,321,590	1,321,590
71	TOTAL Construction (Total of lines 68 thru 70)	73,961,320	8,107,075	82,068,395
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,933,162	327,140	5,260,302
74	Gas Plant	609,927	193,211	803,138
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,543,089	520,351	6,063,440
77	Other Accounts (Specify, provide details in footnote):			
78	Non Utility Property		989,455	989,455
79	Non Operating Expenses	3,531,711	495,662	4,027,373
80	Other Work in Progress	123,435	844,422	967,857
81	Other Balance Sheet Payroll	1,668,746	3,105,441	4,774,187
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	5,323,892	5,434,980	10,758,872
96	TOTAL SALARIES AND WAGES	264,843,563	35,916,932	300,760,495

Schedule Page: 354 Line No.: 70 Column: d

Common Plant

Schedule Page: 354 Line No.: 81 Column: d

DSM Deferrals, PSI accounts, Stores Expense, and Temporary Facilities.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2014/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

(1) and (2) See pages 356.1 and 356.2

(3) Common Utility Plant Expenses are not segregated, but charged to utility departments on a functional basis. South Carolina Electric & Gas Company owns all of the Common Utility Plant of SCANA Corporation. Other subsidiaries of SCANA Corporation that benefit from the use of Common Utility Plant are charged directly by South Carolina Electric & Gas Company for their proportionate share of the related expenses.

(4) July 24, 1948

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Utility Plant In Service	Balance End of Year
118-603 Misc Intangible Plant	$124,733,868
118-689 Land and Land Rights	21,258,577
118-690 Structures and Improvements	144,137,169
118-691 Office Furniture and Equipment	14,294,849
118-692 Transportation Equipment	7,199,667
118-693 Stores Equipment	181,054
118-694 Tools, Shop and Garage Equipment	2,004,209
118-695 Laboratory Equipment	186,683
118-696 Power-Operated Equipment	3,365,727
118-697 Communication Equipment	8,423,821
118-698 Miscellaneous Equipment	6,346,816
118-699 ARC Common Gen Plant	154,102
Total	$332,286,542

Note: Common Plant in service consists of land and buildings devoted jointly to all utility operations, such as general office buildings, storerooms and repair shops and equipment therein. Also, software and transportation equipment used jointly is thus classifed.

Construction Work in Progress - Common Utility Plant

Description of Project	Balance End of Year
980065 IVR Infrastructure and App Software	$ 16,933,520
Other Projects < $500K	2,588,363
Total	$ 19,521,883

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Plant in Service and Depreciation Reserve
Allocable to Utility Departments

Common Utility	Total (a)	Electric (b)	Gas (c)
Plant Allocable to Utility Departments (1)	$332,286,542	$299,456,632	$32,829,910
Less:			
Common Depreciable Reserve Allocable to Utility Departments (2)	162,873,609	146,781,696	16,091,913
Net Common Plant Allocable to Utility Departments	$169,412,933	$152,674,936	$16,737,997

(1) This allocation is based on functional use by Departments.
Percentage:Electric 90.12% and Gas 9.88%

(2) This allocation is based on functional use by Departments of common depreciable property.
Percentages are the same as in note (1).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				1
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				1

Schedule Page: 397 Line No.: 1 Column: e

No activity during reported period.

Schedule Page: 397 Line No.: 2 Column: e

No activity during reported period.

Schedule Page: 397 Line No.: 3 Column: e

No activity during reported period.

Schedule Page: 397 Line No.: 4 Column: e

No activity during reported period.

Schedule Page: 397 Line No.: 5 Column: e

No activity during reported period.

Schedule Page: 397 Line No.: 6 Column: b

No activity during reported period.

Schedule Page: 397 Line No.: 6 Column: c

No activity during reported period.

Schedule Page: 397 Line No.: 6 Column: d

No activity during reported period.

Schedule Page: 397 Line No.: 6 Column: e

PJM Settlement, Inc. prior period adjustments for 2011 and 2012 Balancing Operating Reserves.

This amount has been recorded on the Company's books in Account 565: Transmission of Electricity by Others.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			98,428	14,032	MW	120,406
2	Reactive Supply and Voltage			624,351	14,032	MW	280,123
3	Regulation and Frequency Response			370	1,784	MW	82,907
4	Energy Imbalance	189	MWH	1,756	3,329	MWH	272,868
5	Operating Reserve - Spinning			793	2,000	MW	133,199
6	Operating Reserve - Supplement			793	2,000	MW	193,675
7	Other			-660,512			
8	Total (Lines 1 thru 7)	189		65,979	37,177		1,083,178

Schedule Page: 398 Line No.: 1 Column: b

Reference footnote Line No. 1 Column D for detail on number of units.

Schedule Page: 398 Line No.: 1 Column: c

Reference footnote Line No. 1 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 1 Column: d

Name	Number of Units	Unit of Measure	Dollars
Duke Energy Carolinas, LLC OATT, Rate Schedule 1	0.059533	% Load Ratio Share	$ 322
Santee Cooper OATT, Rate Schedule 1 (Formula Rate)	97 MW/ 194 MWH	MW, MWH	49
South Carolina Electric & Gas Company OATT, Rate Schedule 1	1459 MW/ 3080 MWH	MW, MWH	407
South Carolina Electric & Gas Company OATT, Rate Schedule 1	44 MW/ 204 MWH	MW, MWH	96
Southern Company OATT, Rate Schedule 1	315 MW/ 4063 MWH	MW, MWH	718
Southern Company OATT, Rate Schedule 1	100 MW/ 248,899 MWH	MW, MWH	96,836
		Total	$ 98,428

Schedule Page: 398 Line No.: 2 Column: b

Reference footnote Line No. 2 Column D for detail on number of units.

Schedule Page: 398 Line No.: 2 Column: c

Reference footnote Line No. 2 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 2 Column: d

Name	Number of Units	Unit of Measure	Dollars
Duke Energy Carolinas, LLC OATT, Rate Schedule 2	0.059533	% Load Ratio Share	$ 1,946
Santee Cooper OATT, Rate Schedule 2 (Formula Rate)	97 MW/ 194 MWH	MW, MWH	124
South Carolina Electric & Gas Company OATT, Rate Schedule 2	1459 MW/ 3080 MWH	MW, MWH	940
South Carolina Electric & Gas Company OATT, Rate Schedule 2	44 MW/ 204 MWH	MW, MWH	216
Southern Company OATT, Rate Schedule 2	315 MW/ 4063 MWH	MW, MWH	970
Southern Company OATT, Rate Schedule 2	100 MW/ 248,899 MWH	MW, MWH	132,155
Columbia Energy/Calpine Reactive Supply & Voltage Control (RSV) to SCE&G	Flat Rate	Flat Rate	488,000
		Total	$ 624,351

Schedule Page: 398 Line No.: 3 Column: b

0.059533

Schedule Page: 398 Line No.: 3 Column: c

% Load Ratio Share

Schedule Page: 398 Line No.: 3 Column: d

$370 - Duke Energy Carolinas, LLC OATT, Rate Schedule 3

Schedule Page: 398 Line No.: 4 Column: d

$1,756 - Duke Energy Carolinas, LLC OATT, Rate Schedule 4

Schedule Page: 398 Line No.: 5 Column: b

0.059533

Schedule Page: 398 Line No.: 5 Column: c

% Load Ratio Share

Schedule Page: 398 Line No.: 5 Column: d

$793 - Duke Energy Carolinas, LLC OATT, Rate Schedule 5

Schedule Page: 398 Line No.: 6 Column: b

0.059533

Schedule Page: 398 Line No.: 6 Column: c

% Load Ratio Share

Schedule Page: 398 Line No.: 6 Column: d

$793 - Duke Energy Carolinas, LLC OATT, Rate Schedule 6

Schedule Page: 398 Line No.: 7 Column: d

Name	Dollars
Duke Energy Carolinas, LLC OATT, Direct Assignment Charges and Other Miscellaneous Adjustments	$ 11,926
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services pursuant to SCPSC Docket No.2013-276-E.	(689,580)
Southern Company Services, Inc. Recovery of FERC Annual Charge Factor	16,610
Southern Company Services, Inc. Recovery of Attachment K Charge Factor	532
Southern Company Services, Inc. refund calculated on Transmission Service for 2013.	(1)
PJM Settlement, Inc. prior period adjustments for 2011 and 2012 Balancing Operating Reserves.	1
Total	($660,512)

Schedule Page: 398 Line No.: 8 Column: b

Total is not meaningful due to the summation of dissimilar units of measure.

Schedule Page: 398 Line No.: 8 Column: e

Total is not meaningful due to the summation of dissimilar units of measure.

Schedule Page: 398 Line No.: 8 Column: g

Ancillary Services revenue reported on this schedule is reported as necessary in other supporting schedules within this Form 1 filing.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,603	24	800		244				15
2	February	3,947	12	900		225				13
3	March	3,902	4	800		214				12
4	Total for Quarter 1	12,452				683				40
5	April	3,724	28	1700		171				9
6	May	4,250	13	1700		206				11
7	June	4,548	19	1700		229				13
8	Total for Quarter 2	12,522				606				33
9	July	4,611	27	1800		213				13
10	August	4,756	22	1700		233				13
11	September	4,561	2	1600		233				13
12	Total for Quarter 3	13,928				679				39
13	October	3,721	10	1700		170				9
14	November	4,299	19	700		247				13
15	December	4,209	12	800		225				12
16	Total for Quarter 4	12,229				642				34
17	Total Year to Date/Year	51,131				2,610				146

Schedule Page: 400 Line No.: 1 Column: d

All times are shown in Hour Ending (HE) format.

Schedule Page: 400 Line No.: 1 Column: e

The Company does not take bundled retail service under the terms of its Order No. 890 open access transmission tariff, and the Company has not executed a firm network agreement for service to itself. For purposes of this report, this number may be calculated by subtracting the value in column (f) from the value in column (b). These values are listed below:

Month	MWH
January	4,359
February	3,722
March	3,688
April	3,553
May	4,044
June	4,319
July	4,398
August	4,523
September	4,328
October	3,551
November	4,052
December	3,984
Total	48,521

Also includes amounts in columns (g), (i) and (j).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	22,374,515
3	Steam	8,699,835			
4	Nuclear	4,610,749	23	Requirements Sales for Resale (See instruction 4, page 311.)	955,587
5	Hydro-Conventional	261,328			
6	Hydro-Pumped Storage	372,498	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,840
7	Other	6,104,998			
8	Less Energy for Pumping	524,880	25	Energy Furnished Without Charge	8
9	Net Generation (Enter Total of lines 3 through 8)	19,524,528	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	143,413
10	Purchases	4,940,712	27	Total Energy Losses	998,040
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	24,474,403
12	Received	87			
13	Delivered	1,634			
14	Net Exchanges (Line 12 minus line 13)	-1,547			
15	Transmission For Other (Wheeling)				
16	Received	371,532			
17	Delivered	360,822			
18	Net Transmission for Other (Line 16 minus line 17)	10,710			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	24,474,403			

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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,298,577	52	4,853	7	800
30	February	1,793,528	2,396	3,994	12	900
31	March	1,921,766	94	3,738	4	800
32	April	1,714,660		3,362	28	1700
33	May	2,004,463		4,023	23	1700
34	June	2,258,514	419	4,361	19	1700
35	July	2,380,035		4,536	28	1600
36	August	2,375,570		4,594	22	1700
37	September	2,045,794		4,399	2	1600
38	October	1,848,881		3,480	11	1700
39	November	1,878,351		4,184	19	800
40	December	1,954,264		4,064	12	800
41	TOTAL	24,474,403	2,961			

Schedule Page: 401 Line No.: 16 Column: b

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from SCE&G's system. The MWH supporting these transactions are included in SCE&G's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,271,070	1,234,188
Page 401a	371,532	360,822
Difference	899,538	873,366

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 1	3,191	3,126
Page 329 line 2	209	204
Page 329 line 15	896,138	870,036
Total	899,538	873,366

Schedule Page: 401 Line No.: 17 Column: b

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from SCE&G's system. The MWH supporting these transactions are included in SCE&G's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,271,070	1,234,188
Page 401a	371,532	360,822
Difference	899,538	873,366

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 1	3,191	3,126
Page 329 line 2	209	204
Page 329 line 15	896,138	870,036
Total	899,538	873,366

Schedule Page: 401 Line No.: 29 Column: f

All times are shown in Hour Ending (HE) format.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *V.C. Summer (2/3rds)* (b)	Plant Name: *Urquhart* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	PWR	Conventional
3	Year Originally Constructed	1984	1953
4	Year Last Unit was Installed	1984	1955
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	686.40	100.00
6	Net Peak Demand on Plant - MW (60 minutes)	662	93
7	Plant Hours Connected to Load	7078	1626
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	661	96
10	When Limited by Condenser Water	647	95
11	Average Number of Employees	658	61
12	Net Generation, Exclusive of Plant Use - KWh	4610749000	105893000
13	Cost of Plant: Land and Land Rights	880611	2605060
14	Structures and Improvements	277811939	16814488
15	Equipment Costs	780584789	79455346
16	Asset Retirement Costs	43803621	19806924
17	Total Cost	1103080960	118681818
18	Cost per KW of Installed Capacity (line 17/5) Including	1607.0527	1186.8182
19	Production Expenses: Oper, Supv, & Engr	9291240	60482
20	Fuel	46626853	5595473
21	Coolants and Water (Nuclear Plants Only)	2790759	0
22	Steam Expenses	8079790	259108
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2759022	191190
26	Misc Steam (or Nuclear) Power Expenses	37745367	1312988
27	Rents	0	0
28	Allowances	0	9
29	Maintenance Supervision and Engineering	-6444574	14906
30	Maintenance of Structures	3944397	4517
31	Maintenance of Boiler (or reactor) Plant	17174412	275782
32	Maintenance of Electric Plant	3572623	136616
33	Maintenance of Misc Steam (or Nuclear) Plant	17763934	597190
34	Total Production Expenses	143303823	8448261
35	Expenses per Net KWh	0.0311	0.0798

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear			Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Grams			Barrels	MCF	
38	Quantity (Units) of Fuel Burned	728417	0	0	0	1137875	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	64	0	0	0	1024	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	142.734	4.914	0.000
41	Average Cost of Fuel per Unit Burned	64.010	0.000	0.000	0.000	4.914	0.000
42	Average Cost of Fuel Burned per Million BTU	1.007	0.000	0.000	0.000	4.800	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.053	0.000
44	Average BTU per KWh Net Generation	10038.000	0.000	0.000	0.000	11001.000	0.000

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Wateree* (d)	Plant Name: *McMeekin* (e)	Plant Name: *Canadys* (f)	Line No.
Steam	Steam	Steam	1
Outdoor-Boiler	Semi-Outdoor	Outdoor-Boiler	2
1970	1958	1962	3
1971	1958	1967	4
771.80	293.60	0.00	5
691	259	0	6
8760	7841	0	7
0	0	0	8
684	250	0	9
684	250	0	10
97	65	14	11
3669562000	1377733000	0	12
2119622	15668	5602944	13
124882196	24226486	0	14
743979854	189035576	0	15
11227439	11816170	0	16
882209111	225093900	5602944	17
1143.0540	766.6686	0	18
1441993	380281	0	19
148806950	55555723	0	20
0	0	0	21
748406	1859584	0	22
0	0	0	23
0	0	0	24
2911689	805879	0	25
1775032	844528	0	26
0	12450	0	27
123818	121338	0	28
31435	15918	0	29
698310	221225	0	30
8682982	1429192	0	31
1328667	592479	0	32
812879	697900	0	33
167362161	62536497	0	34
0.0456	0.0454	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Coal	Gas	Oil				36
Tons	Barrels		Tons	MCF	Barrels				37
1506486	22258	0	522395	283634	1509	0	0	0	38
12495	137636	0	12696	1027	138961	0	0	0	39
93.076	129.821	0.000	97.567	4.856	149.654	0.000	0.000	0.000	40
94.669	136.039	0.000	99.868	4.856	135.335	0.000	0.000	0.000	41
3.802	23.533	0.000	4.073	4.730	23.188	0.000	0.000	0.000	42
0.040	0.000	0.000	0.040	0.000	0.000	0.000	0.000	0.000	43
10294.000	0.000	0.000	9846.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Cope* (b)			Plant Name: *Parr #1 & 2* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Package		
3	Year Originally Constructed	1996			1970		
4	Year Last Unit was Installed	1996			1970		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	417.36			39.10		
6	Net Peak Demand on Plant - MW (60 minutes)	423			36		
7	Plant Hours Connected to Load	8313			134		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	415			34		
10	When Limited by Condenser Water	415			27		
11	Average Number of Employees	68			0		
12	Net Generation, Exclusive of Plant Use - KWh	2973345000			1976000		
13	Cost of Plant: Land and Land Rights	3218006			9199		
14	Structures and Improvements	81914631			358157		
15	Equipment Costs	451567163			5166262		
16	Asset Retirement Costs	8291252			-4405		
17	Total Cost	544991052			5529213		
18	Cost per KW of Installed Capacity (line 17/5) Including	1305.8057			141.4121		
19	Production Expenses: Oper, Supv, & Engr	115712			0		
20	Fuel	115093855			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	160520			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1645095			0		
26	Misc Steam (or Nuclear) Power Expenses	1671913			0		
27	Rents	0			0		
28	Allowances	33608			0		
29	Maintenance Supervision and Engineering	15992			0		
30	Maintenance of Structures	225624			0		
31	Maintenance of Boiler (or reactor) Plant	2673666			0		
32	Maintenance of Electric Plant	198951			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	2696633			0		
34	Total Production Expenses	124531569			0		
35	Expenses per Net KWh	0.0419			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	1131820	3190	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12233	136124	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	94.559	132.758	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	94.594	134.659	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.910	23.553	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.037	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9319.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Parr #3 & 4* (d)	Plant Name: *Parr Combined* (e)	Plant Name: *Hagood #4* (f)	Line No.
Gas Turbine		Gas Turbine	1
Package		Package	2
1971		1991	3
1971		1991	4
44.54	83.64	121.89	5
44	80	94	6
129	263	261	7
0	0	0	8
39	0	99	9
33	0	88	10
0	2	0	11
3327000	5303000	17309000	12
6651	15850	96048	13
519260	877417	3534937	14
3474869	8641131	33926255	15
-3185	-7590	9401366	16
3997595	9526808	46958606	17
89.7529	113.9025	385.2540	18
0	48616	0	19
0	787157	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	129178	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	351	0	29
0	2406	0	30
0	0	0	31
0	664060	0	32
0	0	0	33
0	1631768	0	34
0.0000	0.3077	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	41183	5198	0	0	0	0	38
0	0	0	1025	138000	0	0	0	0	39
0.000	0.000	0.000	6.006	135.464	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	6.006	103.988	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	5.857	17.941	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.086	0.222	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Hagood #5* (b)			Plant Name: *Hagood #6* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	2000			1981		
4	Year Last Unit was Installed	2000			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	27.40			27.94		
6	Net Peak Demand on Plant - MW (60 minutes)	23			24		
7	Plant Hours Connected to Load	358			323		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	23			23		
10	When Limited by Condenser Water	20			20		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	5728000			5685000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	350422			687165		
15	Equipment Costs	7461186			9234450		
16	Asset Retirement Costs	0			0		
17	Total Cost	7811608			9921615		
18	Cost per KW of Installed Capacity (line 17/5) Including	285.0952			355.1043		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Hagood Combined* (d)	Plant Name: *Hardeeville Peaking* (e)	Plant Name: *Urquhart #1 Peaking* (f)	Line No.
	Gas Turbine	Gas Turbine	1
	Package	Package	2
	1968	1969	3
	1968	1969	4
177.23	16.32	19.63	5
141	2	14	6
942	3	63	7
0	0	0	8
0	9	16	9
0	9	13	10
9	0	0	11
28722000	4000	550000	12
96048	5261	0	13
4572524	57556	496731	14
50621891	3553212	2260384	15
9401366	-7252	0	16
64691829	3608777	2757115	17
365.0162	221.1260	140.4542	18
12769	359	0	19
3582137	4827	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
299710	125602	0	25
0	0	0	26
0	0	0	27
5	0	0	28
80668	0	0	29
170662	0	0	30
0	0	0	31
113169	22654	0	32
0	0	0	33
4259120	153442	0	34
0.1483	38.3605	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Oil		Oil						36
MCF	Barrels		Barrels						37
248838	16943	0	41	0	0	0	0	0	38
1024	138000	0	138000	0	0	0	0	0	39
5.392	132.184	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
5.392	132.419	0.000	118.667	0.000	0.000	0.000	0.000	0.000	41
5.266	22.847	0.000	20.474	0.000	0.000	0.000	0.000	0.000	42
0.067	0.259	0.000	1.208	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Urquhart #2 Peaking* (b)			Plant Name: *Urquhart #3 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	16.32			16.32		
6	Net Peak Demand on Plant - MW (60 minutes)	10			13		
7	Plant Hours Connected to Load	14			11		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	17			15		
10	When Limited by Condenser Water	14			12		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	80000			97000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	394853			370285		
15	Equipment Costs	1976449			1930506		
16	Asset Retirement Costs	0			0		
17	Total Cost	2371302			2300791		
18	Cost per KW of Installed Capacity (line 17/5) Including	145.3004			140.9798		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Urquhart #4 Peaking* (d)			Plant Name: *Urquhart Comb 1-4* (e)			Plant Name: *Urquhart Comb Cycle* (f)			Line No.
Gas Turbine						Combined Cycle			1
Package						Package			2
1999						2002			3
1999						2002			4
58.90			111.17			547.80			5
49			86			485			6
558			646			10140			7
0			0			0			8
49			0			484			9
48			0			458			10
0			3			0			11
21519000			22246000			1800581000			12
0			0			0			13
497927			1759796			4617640			14
23892533			30059872			260464168			15
0			0			0			16
24390460			31819668			265081808			17
414.0995			286.2253			483.9025			18
0			54369			459057			19
0			1332121			80179257			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			93626			2604098			25
0			0			0			26
0			0			0			27
0			20			203			28
0			63			15785			29
0			676			354460			30
0			0			1423			31
0			243115			2323959			32
0			0			435			33
0			1723990			85938677			34
0.0000			0.0775			0.0477			35
			Gas	Oil		Gas	Oil		36
			MCF	Barrels		MCF	Barrels		37
0	0	0	233108	1970	0	13694174	35655	0	38
0	0	0	1023	137463	0	1023	136587	0	39
0.000	0.000	0.000	4.926	0.000	0.000	5.590	0.000	0.000	40
0.000	0.000	0.000	4.926	93.932	0.000	5.590	103.593	0.000	41
0.000	0.000	0.000	4.816	16.270	0.000	5.467	18.058	0.000	42
0.000	0.000	0.000	0.054	0.175	0.000	0.045	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coit #1 Peaking* (b)			Plant Name: *Coit #2 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.64			19.64		
6	Net Peak Demand on Plant - MW (60 minutes)	19			18		
7	Plant Hours Connected to Load	91			75		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	18			18		
10	When Limited by Condenser Water	14			14		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	1068000			799000		
13	Cost of Plant: Land and Land Rights	36550			27209		
14	Structures and Improvements	98579			83292		
15	Equipment Costs	3427647			2541702		
16	Asset Retirement Costs	-17144			-12763		
17	Total Cost	3545632			2639440		
18	Cost per KW of Installed Capacity (line 17/5) Including	180.5312			134.3910		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Coit Combined* (d)			Plant Name: *Williams #1 Peaking* (e)			Plant Name: *Williams #2 Peaking* (f)			Line No.
			Gas Turbine			Gas Turbine			1
			Package			Package			2
			1972			1972			3
			1972			1972			4
39.27			23.80			23.80			5
37			28			95			6
166			59			67			7
0			0			0			8
0			26			26			9
0			20			20			10
0			0			0			11
1867000			1308000			1439000			12
63759			0			0			13
181871			564588			31825			14
5969349			3264516			3728509			15
-29907			0			0			16
6185072			3829104			3760334			17
157.5012			160.8867			157.9972			18
0			0			0			19
396116			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
38191			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
1197			0			0			29
0			0			0			30
0			0			0			31
140211			0			0			32
0			0			0			33
575715			0			0			34
0.3084			0.0000			0.0000			35
Gas	Oil								36
MCF	Barrels								37
18003	2456	0	0	0	0	0	0	0	38
1026	138000	0	0	0	0	0	0	0	39
6.602	140.536	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
6.602	113.041	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
6.437	19.503	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.116	0.330	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Williams Combined* (b)			Plant Name: *Boeing* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Solar Photovoltaic		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)				Full-Outdoor		
3	Year Originally Constructed				2011		
4	Year Last Unit was Installed				2011		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	47.60			2.60		
6	Net Peak Demand on Plant - MW (60 minutes)	123			0		
7	Plant Hours Connected to Load	126			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	2747000			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	596413			117179		
15	Equipment Costs	6993025			9245463		
16	Asset Retirement Costs	0			0		
17	Total Cost	7589438			9362642		
18	Cost per KW of Installed Capacity (line 17/5) Including	159.4420			3601.0162		
19	Production Expenses: Oper, Supv, & Engr	359			0		
20	Fuel	784223			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	156965			54		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	4			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	13137			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	35495			141338		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	990183			141392		
35	Expenses per Net KWh	0.3605			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Barrels				
38	Quantity (Units) of Fuel Burned	12373	5355	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1026	136796	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.920	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.920	135.159	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.797	23.535	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.074	0.376	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Kapstone Generator* (d)	Plant Name: *Jasper* (e)	Plant Name: *Major Maint. Accrual* (f)	Line No.
Steam	Combined Cycle		1
Outdoor - Boiler	Package		2
1999	2004		3
1999	2004		4
99.31	1001.70	0.00	5
93	948	0	6
8680	6904	0	7
0	0	0	8
85	924	0	9
85	852	0	10
0	35	0	11
573302001	4243528000	0	12
0	2737068	0	13
0	28138017	0	14
11144060	472773273	0	15
0	127011	0	16
11144060	503775369	0	17
112.2149	502.9204	0	18
0	628948	0	19
29567692	160378423	0	20
0	0	0	21
13088946	0	0	22
0	0	0	23
0	0	0	24
0	2634267	-18652	25
0	5823	0	26
0	0	0	27
0	1935	0	28
0	371309	0	29
0	11392	0	30
188	496	-13018	31
0	18267917	382436	32
0	0	-80927	33
42656826	182300510	269839	34
0.0744	0.0430	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	30317946	28241	0	0	0	0	38
0	0	0	1024	140339	0	0	0	0	39
0.000	0.000	0.000	5.145	137.573	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	5.145	107.100	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	5.066	18.170	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.038	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: f

In December 2012, the Company retired the 90MW Unit 1 at Canadys Station. In November 2013, the Company retired the remaining units, Unit 2 (115MW) and Unit 3 (180MW).

Schedule Page: 402 Line No.: 1 Column: b

SCE&G's portion (two-thirds) of jointly owned plant.

Instruction No. 12 - V. C. Summer Nuclear Station

(a) Nuclear fuel amortization, which is included in Production Expenses, is recorded using the units-of-production method and, as applicable, through May 15, 2014, includes amounts necessary to satisfy obligations to the United States Department of Energy under a contract for disposal of spent nuclear fuel. Normal operation and maintenance costs are charged to expenses as incurred with appropriate application of the accrual method of accounting. Pursuant to an order issued by the South Carolina Public Service Commission, estimated refueling outage operation and maintenance costs for the five outages scheduled Spring 2014 through Spring 2020 are being accrued over the 90 month period (January 2013 through June 2020) covered by these outages.

(b) Cost is recorded for nuclear fuel on the batch basis. At reload, the number of new assemblies required to complete the core requirement of 157 assemblies is designated as the new batch. All costs for this new batch are reported according to classification of component by batch number. Each batch consists of costs for U308, conversion, enrichment, fabrication, and allowance for funds used during construction.

(c) The V. C. Summer Nuclear Station is a Westinghouse PWR Nuclear Power Plant. Fuel material is U02 contained in Zircaloy tube cladding. The equilibrium cycle has approximately 65.5 metric tons of Uranium metal with a nominal U-235 enrichment of 4.6% to 4.8%. The reactor is licensed to allow operation of 2900 MWt.

Schedule Page: 403 Line No.: 5 Column: f

As of December 2013, no remaining units were in service. Therefore, no installed capacity is being reported for this plant.

Schedule Page: 403 Line No.: 18 Column: f

As of December 2013, no remaining units were in service and the only remaining cost (asset value) is land. Therefore, no "cost per KW installed capacity" is being reported for this plant.

Schedule Page: 403.1 Line No.: 2 Column: e

Parr Steam Plant functions in a combined cycle operation with four gas turbine peaking units and two heat recovery boilers. Production expenses and fuel data are for the entire operation. See column (e), lines 19-44 for combined data on Parr units.

Schedule Page: 402.1 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: d

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: e

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: f

Employees not specifically assigned to individual units.

Name of Respondent South Carolina Electric & Gas Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2014/Q4

FOOTNOTE DATA

Schedule Page: 402.2 Line No.: 11 Column: b
Employees not specifically assigned to individual units.

Schedule Page: 402.2 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: e
Unattended-automatic.

Schedule Page: 403.2 Line No.: 11 Column: f
Employees not specifically assigned to individual units.

Schedule Page: 402.3 Line No.: 11 Column: b
Employees not specifically assigned to individual units.

Schedule Page: 402.3 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: e
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: f
Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: b
Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: e
Unattended-automatic

Schedule Page: 403.4 Line No.: 11 Column: f
Unattended-automatic.

Schedule Page: 402.5 Line No.: -1 Column: c
This is a rooftop mounted solar electric generator that provides electricity exclusively for use by a large commercial customer. None of the output flows onto the grid.

Schedule Page: 403.5 Line No.: -1 Column: f
The major maintenance accrual represents an SCPSC approved (SCPSC Docket No. 2009-489-E) annual accrual of $18.4 million through 2017. The Company is allowed to collect $18.4 million through retail electric rates to offset expenditures relating to certain turbine maintenance. Under this mechanism, the Company records an annual expense accrual of $18.4 million and records any difference between actual expenses incurred and this accrual as a regulatory asset or liability as appropriate. Prior to July, 2010, the Company had an annual accrual of $8.5 million per approved SCPSC Docket No. 2004-178-E.

For the year ended December 31, 2014, the Company incurred actual expenses in the amount of $19.4 million for major maintenance that is subject to this accrual. Cumulative costs for turbine maintenance in excess of cumulative collections are classified as a regulatory asset on the balance sheet.

Schedule Page: 402.5 Line No.: 11 Column: b
Unattended-automatic

Schedule Page: 403.5 Line No.: 11 Column: d
SCE&G receives shaft horsepower from Kapstone Charleston Kraft LLC, a biomass/coal cogeneration facility, to operate SCE&G's generator.

Schedule Page: 402 Line No.: 43 Column: c2
All fuels.

Schedule Page: 402 Line No.: 43 Column: d1
All fuels.

Schedule Page: 402 Line No.: 43 Column: e1

All fuels.

Schedule Page: 402 Line No.: 44 Column: c2

All fuels.

Schedule Page: 402 Line No.: 44 Column: d1

All fuels.

Schedule Page: 402 Line No.: 44 Column: e1

All fuels.

Schedule Page: 402.1 Line No.: 43 Column: b1

All fuels.

Schedule Page: 402.1 Line No.: 44 Column: b1

All fuels.

Schedule Page: 402.3 Line No.: 43 Column: f1

All fuels.

Schedule Page: 402.5 Line No.: 43 Column: e1

All fuels.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1894 Plant Name: Parr (b)	FERC Licensed Project No. 516 Plant Name: Saluda (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1914	1930
4	Year Last Unit was Installed	1921	1971
5	Total installed cap (Gen name plate Rating in MW)	14.88	207.30
6	Net Peak Demand on Plant-Megawatts (60 minutes)	28	202
7	Plant Hours Connect to Load	8,721	7,224
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	12	200
10	(b) Under the Most Adverse Oper Conditions	7	200
11	Average Number of Employees	4	5
12	Net Generation, Exclusive of Plant Use - Kwh	50,306,000	110,245,000
13	Cost of Plant		
14	Land and Land Rights	603,147	6,162,180
15	Structures and Improvements	1,902,522	7,665,418
16	Reservoirs, Dams, and Waterways	4,272,776	354,621,406
17	Equipment Costs	5,135,101	13,278,164
18	Roads, Railroads, and Bridges	124,198	233,526
19	Asset Retirement Costs	0	-8,520
20	TOTAL cost (Total of 14 thru 19)	12,037,744	381,952,174
21	Cost per KW of Installed Capacity (line 20 / 5)	808.9882	1,842.5093
22	Production Expenses		
23	Operation Supervision and Engineering	80,738	296,793
24	Water for Power	0	0
25	Hydraulic Expenses	40,009	1,002,704
26	Electric Expenses	73,533	12,262
27	Misc Hydraulic Power Generation Expenses	51,536	204,429
28	Rents	0	0
29	Maintenance Supervision and Engineering	879	11,013
30	Maintenance of Structures	44	16
31	Maintenance of Reservoirs, Dams, and Waterways	72,802	291,115
32	Maintenance of Electric Plant	122,799	251,904
33	Maintenance of Misc Hydraulic Plant	8,862	13,724
34	Total Production Expenses (total 23 thru 33)	451,202	2,083,960
35	Expenses per net KWh	0.0090	0.0189

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2535 Plant Name: Stevens Creek (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1914			3
1926			4
17.28	0.00	0.00	5
20	0	0	6
8,743	0	0	7
			8
10	0	0	9
8	0	0	10
4	0	0	11
80,471,000	0	0	12
			13
410,559	0	0	14
2,880,962	0	0	15
6,432,284	0	0	16
5,085,651	0	0	17
128,812	0	0	18
-1,935	0	0	19
14,936,333	0	0	20
864.3711	0.0000	0.0000	21
			22
100,105	0	0	23
0	0	0	24
135,828	0	0	25
12,158	0	0	26
32,237	0	0	27
0	0	0	28
1,509	0	0	29
162,333	0	0	30
19,097	0	0	31
352,344	0	0	32
13,869	0	0	33
829,480	0	0	34
0.0103	0.0000	0.0000	35

Schedule Page: 406 Line No.: 1 Column: b

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: c

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: d

Operated under license from the Federal Energy Regulatory Commission.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 1984 Plant Name: Fairfield (b)
1	Type of Plant Construction (Conventional or Outdoor)	Outdoor
2	Year Originally Constructed	1978
3	Year Last Unit was Installed	1978
4	Total installed cap (Gen name plate Rating in MW)	511
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	515
6	Plant Hours Connect to Load While Generating	3,503
7	Net Plant Capability (in megawatts)	576
8	Average Number of Employees	28
9	Generation, Exclusive of Plant Use - Kwh	372,498,000
10	Energy Used for Pumping	524,880,000
11	Net Output for Load (line 9 - line 10) - Kwh	-152,382,000
12	Cost of Plant	
13	Land and Land Rights	22,147,163
14	Structures and Improvements	36,207,392
15	Reservoirs, Dams, and Waterways	74,478,309
16	Water Wheels, Turbines, and Generators	67,430,661
17	Accessory Electric Equipment	15,215,534
18	Miscellaneous Powerplant Equipment	6,190,216
19	Roads, Railroads, and Bridges	1,328,336
20	Asset Retirement Costs	-500
21	Total cost (total 13 thru 20)	222,997,111
22	Cost per KW of installed cap (line 21 / 4)	436.2228
23	Production Expenses	
24	Operation Supervision and Engineering	247,044
25	Water for Power	
26	Pumped Storage Expenses	158,318
27	Electric Expenses	19,898
28	Misc Pumped Storage Power generation Expenses	305,503
29	Rents	
30	Maintenance Supervision and Engineering	122,236
31	Maintenance of Structures	122
32	Maintenance of Reservoirs, Dams, and Waterways	432,429
33	Maintenance of Electric Plant	1,629,022
34	Maintenance of Misc Pumped Storage Plant	87,007
35	Production Exp Before Pumping Exp (24 thru 34)	3,001,579
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	3,001,579
38	Expenses per KWh (line 37 / 9)	0.0081

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
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			36
			37
			38

Schedule Page: 408 Line No.: 38 Column: b

Required information per FERC Order No. 784, Docket No. AI14-1-000

Expenses per KWH of Generation and Pumping (Line 37/(Line 9 + Line 10)) = .0033

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro-Neal Shoals					
2	Hydro License					
3	Project # 2315	1905	4.42	5.0	20,306,000	7,953,780
4						
5						
6						
7						
8						
9						
10						
11						
12						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
391	232,057		262,382			3
						4
						5
						6
						7
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						10
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						12
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						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	115 KV System	Various	115.00	230.00	Various	102.54	7.37	
2	115 KV System	Various	115.00	115.00	Various	1,508.35	100.80	
3	46 KV System	Various	46.00	115.00	Various	42.73		
4	46 KV System	Various	46.00	46.00	Various	604.30	25.77	
5	33 KV System	Various	33.00	33.00	Various	66.88	3.29	
6	13.8 KV System	SPA	13.80	46.00	Various	0.34		1
7	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP	11.10		1
8	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP	2.90	2.90	2
9	230 KV System							
10	CEC Cola Energy	Fold-in	230.00	230.00	Steel-SP	5.88		1
11	Canadys	Sumter	230.00	230.00	Wood-H	32.00		1
12	Canadys	Faber Place #1	230.00	230.00	Wood-H	40.34		1
13	Canadys	Faber Place #2	230.00	230.00	Wood-H	42.80		1
14	Canadys	Yemassee	230.00	230.00	Wood-H	30.30		1
15	Canadys	Urquhart	230.00	230.00	Wood-H	79.47		1
16	Canadys	Graniteville-SRP	230.00	230.00	Wood-H	0.08		1
17	Canadys	Williams	230.00	230.00	Steel-SP	0.96		1
18	Church Creek	Yemassee	230.00	230.00	Various	52.10		1
19	Cope	Orangeburg	230.00	230.00	Steel-SP	22.05		2
20	Cope	Canadys	230.00	230.00	Steel-SP	40.53		2
21	Edenwood	Denny Terrace	230.00	230.00	Wood-H	12.16		1
22	Edenwood	McMeekin	230.00	230.00	Various	11.48		1
23	Edenwood	Tie	230.00	230.00	Wood-H	1.45		1
24	Edenwood	Owens Steel	230.00	230.00	Steel-SP	0.41		1
25	Fairfield	Summer	230.00	230.00	Wood-H	2.79		1
26	Goose Creek	Ashley Phos.	230.00	230.00	Wood-H	3.10		1
27	Graniteville Sub	Graniteville Sub	230.00	230.00	Steel	0.06		1
28	Graniteville	Urquhart	230.00	230.00	Wood-H	11.23		1
29	Hanahan	Bushy Park	230.00	230.00	Wood-H	10.50		1
30	Hopkins	Tap	230.00	230.00	Steel-SP	2.84		1
31	Huron	Tap	230.00	230.00	Wood-H	0.11		1
32	Jasper	Yemassee#1	230.00	230.00	Steel-SP	39.49		2
33	Jasper	Yemassee#2	230.00	230.00	Steel-SP	39.27		2
34	Jasper	Purrysburg (Santee)	230.00	230.00	Steel-SP	1.24		2
35	Ladson	Ashley Phos.	230.00	230.00	Wood-H	4.60		1
36					TOTAL	3,411.18	182.00	84

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
Various	1,307,722	12,970,562	14,278,284					1
Various	31,058,763	266,668,386	297,727,149					2
Various	393,946	2,262,492	2,656,438					3
Various	2,157,896	43,446,504	45,604,400					4
Various	62,375	4,369,911	4,432,286					5
336mcm								6
336mcm								7
336mcm	4,929	228,413	233,342					8
	14,023,510	184,251,610	198,275,120					9
1272mcm								10
795mcm								11
795mcm								12
795mcm								13
Various								14
1272mcm								15
795mcm								16
1272mcm								17
1272mcm								18
795mcm								19
795mcm								20
1272mcm								21
Various								22
1272mcm								23
1272mcm								24
1272mcm								25
1272mcm								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
1272mcm								32
1272mcm								33
1272mcm								34
795mcm								35
	67,944,230	590,522,051	658,466,281	380,296	5,807,021		6,187,317	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	McMeekin	Parr	230.00	230.00	Wood-H	16.66		1
2	Parr	Denny Terrace	230.00	230.00	Wood-H	21.96		1
3	Parr	Duke	230.00	230.00	Tower	10.90	10.90	1
4	Pepperhill	Mateeba	230.00	230.00	Wood-H	7.10		1
5	Pineland	Denny Terrace	230.00	230.00	Steel-SP	8.46		2
6	St. George	Ladson	230.00	230.00	Wood-H	33.00		1
7	St. George	Williams	230.00	230.00	Steel-SP	0.97		1
8	Summer	Denny Terrace	230.00	230.00	Wood-H	4.53		1
9	Summer	Parr #1	230.00	230.00	Wood-H	2.38		1
10	Summer	Parr #2	230.00	230.00	Wood-H	2.26		1
11	Summer	Graniteville	230.00	230.00	Wood-H	63.26		1
12	Summer	Pineland	230.00	230.00	Wood-H	26.83		1
13	Summer	Denny Terrace	230.00	230.00	Wood-H	26.26		1
14	Summerville	Tap	230.00	230.00	Wood-H		0.08	1
15	Timberlake	Tap	230.00	230.00	Wood-SP	8.41		1
16	Urquhart	Fold-in	230.00	230.00	Steel-H	9.55		1
17	VCS1	Killian	230.00	230.00	Steel-SP	3.36		1
18	VCS1	Killian	230.00	230.00	Steel-SP	38.66		2
19	VCS2	Lake Murray	230.00	230.00		20.53	20.53	2
20	Vogtle	SRP	230.00	230.00	Steel-H	17.10		1
21	Ward	Tie	230.00	230.00	Wood-H	0.07		1
22	Wateree	Denny Terrace	230.00	230.00	Wood-H	29.94		1
23	Wateree	Edenwood	230.00	230.00	Wood-H	27.80		1
24	Wateree	Sumter	230.00	230.00	Wood-H	0.86		1
25	Wateree	St. George	230.00	230.00	Wood-H	45.60		1
26	Wateree	Pineland	230.00	230.00	Wood-H	38.18		1
27	Wateree	Hercules	230.00	230.00	Wood-H	0.45		1
28	Wateree	Orangeburg	230.00	230.00	Wood-H	27.10		1
29	Wateree-Edenwood	Columbia	230.00	230.00	Steel-H	2.95	2.95	2
30	Williams	Wateree	230.00	230.00	Wood-H	10.30		1
31	Williams	Canadys	230.00	230.00	Wood-H	9.60	0.70	1
32	Williams	Faber Place #1	230.00	230.00	Steel-SP	0.53		2
33	Williams	Faber Place #2	230.00	230.00	Tower-H	17.31	6.71	2
34	Williams	Tie	230.00	230.00	Concrete	0.08		1
35	Williams	DuPont	230.00	230.00	Wood-H	6.60		1
36					TOTAL	3,411.18	182.00	84

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795mcm								1
795mcm								2
954mcm								3
795mcm								4
1272mcm								5
795mcm								6
1272mcm								7
1272mcm								8
1272mcm								9
1272mcm								10
1272mcm								11
1272mcm								12
1272mcm								13
1272mcm								14
1272mcm								15
1272mcm								16
1272mcm								17
1272mcm								18
1272mcm								19
795mcm								20
1272mcm								21
Various								22
1272mcm								23
1272mcm								24
1272mcm								25
1272mcm								26
1272mcm								27
795mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
1272mcm								32
1272mcm								33
1272mcm								34
1272mcm								35
	67,944,230	590,522,051	658,466,281	380,296	5,807,021		6,187,317	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Yemassee	Burton	230.00	230.00	Steel-SP	21.31		2
2	Yemassee	Santee	230.00	230.00	Wood-H	2.93		2
3	Underground							
4	33 KV System					0.23		2
5	46 KV System					0.90		1
6	115 KV System					19.88		1
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,411.18	182.00	84

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272mcm								1
1272mcm								2
								3
250mcm		16,443	16,443					4
750mcm		1,623,433	1,623,433					5
2250kcm	18,935,089	74,684,297	93,619,386					6
				380,296	5,807,021		6,187,317	7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	67,944,230	590,522,051	658,466,281	380,296	5,807,021		6,187,317	36

Schedule Page: 422 Line No.: 1 Column: h

Various

Schedule Page: 422 Line No.: 2 Column: h

Various

Schedule Page: 422 Line No.: 3 Column: h

Various

Schedule Page: 422 Line No.: 4 Column: h

Various

Schedule Page: 422 Line No.: 5 Column: h

Various

Schedule Page: 422 Line No.: 9 Column: l

Total Capitalized Cost of 230 KV System

Schedule Page: 422.2 Line No.: 7 Column: a

Reported costs in Column L reflect total costs including balances recorded in Account 106-Completed Construction Not Classified. Columns A through I include statistical data related to the unitized plant only.

Schedule Page: 422.2 Line No.: 7 Column: m

Operation expense includes Accounts 563 and 564.

Schedule Page: 422.2 Line No.: 7 Column: n

Maintenance expense includes Accounts 571 and 572.

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TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OVERHEAD:						
2	Hamlin	Isle of Palms	1.82	Steel	27.00	1	1
3	Blythewood	Winnsboro	4.28	N/A		2	2
4	Blythewood	Winnsboro	0.20	Steel	24.00	1	1
5							
6	Blythewood PMSS	Killian	7.37	N/A		2	2
7							
8	VCS2	Lake Murray	20.53	N/A		2	2
9	VCS1	Killian	3.36	Steel	5.00	1	1
10	VCS1	Killian	38.66	Steel	41.00	2	2
11	Williams	Faber Place #1	0.53	Steel	15.00	2	2
12	Eutawville Tap		6.47	Steel	12.00	1	1
13	Devro Teepak Tap		0.13	Steel	35.00	1	1
14							
15	Parr	Winnsboro #2	1.14	Steel	2.00	2	2
16	Parr	Winnsboro #2	-2.25	N/A		1	1
17							
18	UNDERGROUND:						
19	Hamlin	Isle of Palms	5.00	N/A		1	1
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		87.24		161.00	19	19

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
795	ACSR		115		2,142,900	470,843		2,613,743	2
1272	ACSR		115			1,009,748		1,009,748	3
795	ACSR		115		98,772	20,966		119,738	4
									5
795	ACSR		115			829,879		829,879	6
									7
1272	ACSR		230			1,224,757		1,224,757	8
1272	ACSR		230		137,373	207,457		344,830	9
1272	ACSR		230		6,196,011	4,662,870		10,858,881	10
1272	ACSR		230		642,549	118,040		760,589	11
795	ACSR		115		4,497,280			4,497,280	12
477	ACSR		115		109,556			109,556	13
									14
1272	ACSR		115		310,920	252,506		563,426	15
477	ACSR								16
									17
									18
2250	KCM		115		5,412,123	26,134,873		31,546,996	19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					19,547,484	34,931,939		54,479,423	44

Schedule Page: 424 Line No.: 6 Column: k

Design Voltage 230

Schedule Page: 424 Line No.: 16 Column: a

The Parr-Winnsboro line #2 length was reduced in 2014.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Aiken, Aiken County	Trans-U	115.00	46.00	
2	Aiken, Aiken County	Trans-U	115.00	12.00	
3	Barnwell, Barnwell County	Trans-U	115.00	46.00	
4	Batesburg, City of Batesburg	Trans-U	115.00	33.00	
5	Bayview, Mt. Pleasant City	Trans-U	115.00	24.94	
6	Blackville 115-46KV, Barnwell County	Trans-U	115.00	46.00	
7	Burton Transmission, Beaufort County	Trans-U	230.00	115.00	
8	Burton Transmission, Beaufort County	Trans-U	115.00	46.00	
9	Calhoun County, Calhoun County	Trans-U	115.00	46.00	
10	Calhoun Falls, Calhoun Falls City	Trans-U	115.00	46.20	
11	Calhoun Falls, Calhoun Falls City	Trans-U	43.80	13.09	
12	Callawassie, Jasper County	Trans-U	115.00	46.20	
13	Canadys Sub, Colleton County	Trans-U	115.00	4.16	
14	Canadys Sub, Colleton County	Trans-U	230.00	115.00	
15	Charleston, Charleston County	Trans-U	115.00	24.90	
16	Church Creek, Charleston County	Trans-U	230.00	115.00	
17	Coit Gas Turbine, Richland County	Trans-U	13.80	34.50	
18	Coit, Richland County	Trans-U	115.00	24.94	
19	Coit, Richland County	Trans-U	115.00	34.64	
20	Columbia Industrial Park, Richland County	Trans-U	230.00	115.00	
21	Cope, Orangeburg County	Trans-U	230.00	115.00	
22	Cope, Orangeburg County	Trans-U	115.00	230.00	
23	Denmark, City of Denmark	Trans-U	115.00	46.20	
24	Denny Terrace, Richland County	Trans-U	230.00	115.00	
25	Eastman Chemical, Calhoun County	Trans-U	115.00	13.80	
26	Edenwood, City of Cayce	Trans-U	230.00	115.00	
27	Faber Place, City of North Charleston	Trans-U	115.00	24.94	
28	Faber Place, City of North Charleston	Trans-U	230.00	115.00	
29	Fairfax, Allendale County	Trans-U	115.00	46.20	
30	Fairfield Pumped Storage, Fairfield County	Trans-U	13.80	230.00	
31	Goose Creek, Hanahan City	Trans-U	230.00	115.00	
32	Graniteville #1, Aiken County	Trans-U	115.00	46.00	
33	Graniteville #1, Aiken County	Trans-U	230.00	115.00	
34	Graniteville #2, Aiken County	Trans-U	230.00	115.00	
35	Hagood, Charleston County	Trans-U	115.00	13.80	
36	Hagood, Charleston County	Trans-U	13.20	115.00	
37	Hamlin, Charleston County	Trans-U	115.00	25.00	
38	Hampton, Hampton County	Trans-U	115.00	46.00	
39	Hanahan, Hanahan City	Trans-U	115.00	25.00	
40	Hanahan, Hanahan City	Trans-U	115.00	46.00	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
28	1					1
22	1					2
56	2					3
28	1					4
65	2					5
28	1					6
224	1					7
84	3	1				8
28	1					9
50	2	1				10
7	1					11
25	1					12
11	1					13
224	1					14
67	2					15
560	2					16
56	2					17
22	1					18
56	1					19
336	1					20
224	1					21
548	1					22
56	2					23
672	2					24
90	4					25
448	2					26
67	3					27
672	2	1				28
56	2					29
538	3	1				30
336	1					31
56	2					32
448	2					33
336	1					34
60	1					35
148	1					36
140	4					37
84	3	2				38
79	3					39
56	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hardeeville Gas Turbine, Jasper County	Trans-U	13.20	43.80	
2	Hardeeville, Jasper County	Trans-U	115.00	46.00	
3	Hobcaw, Charleston County	Trans-U	115.00	24.94	
4	Hopkins, Richland County	Trans-U	230.00	115.00	
5	Jasper Gas Turbine, Jasper County	Trans-U	18.00	230.00	
6	Jasper Gas Turbine, Jasper County	Trans-U	21.00	230.00	
7	Kendrick, Richland County	Trans-U	115.00	24.90	
8	Kendrick, Richland County	Trans-U	115.00	35.00	
9	Killian, Richland County	Trans-U	230.00	115.00	
10	Lake Murray, Lexington County	Trans-U	230.00	115.00	
11	Lyles, Richland County	Trans-U	230.00	115.00	
12	Lyles, RIchland County	Trans-U	115.00	23.00	
13	Lyles, Richland County	Trans-U	115.00	35.00	
14	McCormick, McCormick County	Trans-U	115.00	46.00	
15	McCormick, McCormick County	Trans-U	115.00	46.00	
16	McMeekin, Lexington County	Trans-U	13.80	114.00	
17	Orangeburg #1, Orangeburg County	Trans-U	115.00	46.00	
18	Orangeburg #1, Orangeburg County	Trans-U	115.00	46.00	
19	Orangebury 230KV, Orangeburg County	Trans-U	230.00	115.00	
20	Parr Gas Turbine, Fairfield County	Trans-U	13.20	115.00	
21	Parr Hydro, Fairfield County	Trans-U	2.30	13.80	
22	Parr Steam, Fairfield County	Trans-U	115.00	13.20	
23	Pepperhill, Charleston County	Trans-U	230.00	115.00	
24	Pineland, Richland County	Trans-U	230.00	115.00	
25	Rader, Richland County	Trans-U	115.00	24.90	
26	Ridgeville, City of Ridgeville	Trans-U	115.00	46.00	
27	Ritter, Colleton County	Trans-U	230.00	115.00	
28	Saluda Hydro, Lexington County	Trans-U	13.20	115.00	
29	Saluda Hydro, Lexington County	Trans-U	115.00	23.00	
30	Saluda Hydro, Lexington County	Trans-U	115.00	13.20	
31	Santee, Orangeburg County	Trans-U	230.00	46.20	
32	Santee, Orangeburg County	Trans-U	115.00	46.00	
33	Santee, Orangeburg County	Trans-U	230.00	115.00	
34	Savannah River, Government Land	Trans-U	230.00	115.00	
35	St. Andrews, Charleston City	Trans-U	115.00	24.90	
36	St. George, Dorchester County	Trans-U	115.00	46.00	
37	Stevens Creek Hydro, Columbia County, Ga.	Trans-U	2.30	46.00	
38	Stevens Creek Hydro, Columbia County, Ga.	Trans-U	46.00	2.30	
39	Stevens Creek Sub, Columbia County, Ga.	Trans-U	115.00	46.20	
40	Summerville, Berkeley County	Trans-U	230.00	115.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
36	2					1
28	1					2
28	1					3
336	1					4
700	3					5
500	1					6
56	2	1				7
56	1					8
336	1					9
672	2	1				10
336	1	1				11
56	2					12
56	1					13
28	1	2				14
30	1					15
350	2					16
25	1					17
56	2					18
672	2					19
98	2	1				20
25	3					21
34	1					22
336	1					23
672	2	1				24
45	2					25
28	1					26
336	1					27
133	3					28
65	2					29
133	2					30
28	1					31
28	1					32
140	1					33
336	1					34
23	1					35
28	1					36
14	2					37
14	2					38
28	1	1				39
560	2					40

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Thomas Island, Charleston County	Trans-U	115.00	24.94	
2	Trenton, Edgefield County	Trans-U	115.00	24.90	
3	Trenton, Edgefield County	Trans-U	115.00	34.60	
4	Trenton, Edgefield County	Trans-U	115.00	34.60	
5	Urquhart 115-46KV, Aiken County	Trans-U	115.00	46.00	
6	Urquhart Gas Turbine, Aiken County	Trans-U	13.20	115.00	
7	Urquhart Plant, Aiken County	Trans-U	13.80	115.00	
8	V. C. Summer Substation, Fairfield County	Trans-U	22.00	242.00	
9	Ward, Saluda County	Trans-U	230.00	115.00	
10	Ward, Saluda County	Trans-U	115.00	33.00	
11	Ward, Saluda County	Trans-U	115.00	33.00	
12	Wateree Plant, Richland County	Trans-U	21.00	230.00	
13	Wateree Plant, Richland County	Trans-U	230.00	13.80	
14	Williams Gas Turbine, Berkeley County	Trans-U	13.20	115.00	
15	Williams St., Columbia City	Trans-U	115.00	33.00	
16	Williams St., Columbia City	Trans-U	115.00	24.90	
17	Williams Station, Berkeley County	Trans-U	20.00	242.00	
18	Williams Station, Berkeley County	Trans-U	230.00	115.00	
19	Williams Station, Berkeley County	Trans-U	230.00	4.16	
20	Williams Station, Berkeley County	Trans-U	230.00	25.00	
21	Williston Industrial Park, Barnwell County	Trans-U	115.00	46.00	
22	Yemassee, City of Yemassee	Trans-U	230.00	115.00	
23					
24					
25	Distribution Substations:				
26	Adams Run, Charleston County	Dist-U	115.00	24.94	
27	Adams Run, Charleston County	Dist-U	115.00	46.00	
28	Aiken #2, Aiken County	Dist-U	115.00	13.09	
29	Aiken #3, Aiken County	Dist-U	115.00	13.09	
30	Aiken Hampton Avenue, Aiken City	Dist-U	115.00	13.09	
31	Aiken Industrial Park, Aiken City	Dist-U	46.00	24.90	
32	Aiken, Steifeltown, Aiken County	Dist-U	115.00	13.09	
33	Allendale, Allendale City	Dist-U	115.00	13.09	
34	Arrowwood Road, Richland County	Dist-U	115.00	24.90	
35	Ashley Phosphate, North Charleston City	Dist-U	115.00	24.90	
36	Bacon's Bridge, Summerville City	Dist-U	115.00	24.90	
37	Baldock, Allendale County	Dist-U	115.00	13.09	
38	Bamberg Central, Bamberg City	Dist-U	43.80	13.80	
39	Barnwell City, Barnwell City	Dist-U	46.00	13.09	
40	Barnwell Heights, Barnwell City	Dist-U	46.00	13.09	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
76	2					1
22	1	2				2
23	3					3
28	1					4
48	2					5
64	2					6
645	8					7
1232	1	1				8
140	1					9
22	1					10
28	1					11
1008	2					12
80	2					13
70	1					14
106	4					15
59	2					16
785	1	1				17
560	2					18
93	2					19
101	2					20
32	6					21
784	3					22
						23
						24
						25
50	2					26
112	2					27
50	2					28
50	2					29
28	1					30
11	1					31
22	1					32
22	1					33
22	1					34
82	3					35
37	1					36
22	1					37
14	2					38
11	1					39
11	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Barnwell Industrial Park, Barnwell County	Dist-U	43.80	13.90	
2	Batesburg, Batesburg City	Dist-U	33.00	8.32	
3	Bayfront, Charleston CIty	Dist-U	115.00	24.90	
4	Beaufort Central, Beaufort City	Dist-U	115.00	13.09	
5	Beaufort Industrial Park, Beaufort County	Dist-U	115.00	13.09	
6	Bee Street, Charleston County	Dist-U	115.00	14.40	
7	Beech Island, Aiken County	Dist-U	46.00	15.00	
8	Bell Wright, Berkeley County	Dist-U	115.00	25.00	
9	Belmont, Richland County	Dist-U	115.00	24.90	
10	Belvedere, North Augusta City	Dist-U	115.00	13.09	
11	Blackville 46-12KV, Barnwell County	Dist-U	46.00	13.09	
12	Bluffton, Beaufort County	Dist-U	115.00	25.00	
13	Blythewood, Richland County	Dist-U	115.00	24.90	
14	Boney Rd., Fairfield County	Dist-U	115.00	23.00	
15	Boney Rd., Fairfield County	Dist-U	115.00	24.90	
16	Boone Hill, Dorchester County	Dist-U	115.00	24.90	
17	Bowman, Orangeburg County	Dist-U	115.00	8.73	
18	Brookwood, West Columbia City	Dist-U	115.00	24.90	
19	Burton Central, Beaufort County	Dist-U	115.00	13.09	
20	CAE Ind Park, Lexington County	Dist-U	115.00	24.90	
21	Cainhoy Temp., Charleston County	Dist-U	115.00	24.90	
22	Calhoun Street, Columbia City	Dist-U	115.00	8.32	
23	Callawassie Island, Jasper County	Dist-U	115.00	23.00	
24	Carlisle, Carlisle City	Dist-U	115.00	23.00	
25	Center Sub, Aiken County	Dist-U	43.80	24.90	
26	Charleston Airport, North Charleston City	Dist-U	115.00	24.90	
27	Charlotte Street, Charleston City	Dist-U	115.00	14.40	
28	Church Creek, Charleston City	Dist-U	115.00	24.90	
29	Circle Drive, Richland County	Dist-U	115.00	8.72	
30	Clearwater, Aiken County	Dist-U	115.00	13.09	
31	Cloverleaf, Aiken County	Dist-U	115.00	13.09	
32	Colonial Heights, Richland County	Dist-U	115.00	24.90	
33	Columbia Airport, Springdale City	Dist-U	115.00	24.90	
34	Columbia Industrial Park, Richland County	Dist-U	115.00	24.90	
35	Congaree Creek, Cayce City	Dist-U	115.00	23.00	
36	Congaree Vista, Richland County	Dist-U	115.00	24.90	
37	Coosaw, Charleston County	Dist-U	115.00	25.00	
38	Cromer Rd., Lexington County	Dist-U	115.00	23.00	
39	Deer Park, Charleston County	Dist-U	115.00	24.94	
40	Denmark Industrial Park, Denmark City	Dist-U	46.00	13.09	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
11	1					2
40	1					3
28	1					4
22	1					5
202	4					6
11	1					7
28	1					8
50	2					9
22	1					10
11	1					11
56	2					12
77	2					13
23	1					14
22	1					15
60	2					16
21	2					17
28	1					18
56	2					19
28	1					20
56	2					21
22	1					22
28	1	1				23
13	4	1				24
11	1					25
40	1					26
101	4					27
75	2					28
22	1					29
28	1					30
22	1					31
22	1					32
22	1					33
40	1					34
28	1					35
37	1					36
37	1					37
37	1					38
22	1					39
11	1	1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Dentsville, Richland County	Dist-U	115.00	24.90	
2	Dixiana, Lexington County	Dist-U	115.00	24.90	
3	East Columbia, Richland County	Dist-U	115.00	24.90	
4	Edmund, Lexington County	Dist-U	115.00	24.90	
5	Estill Southside, Estill City	Dist-U	46.00	12.00	
6	Estill, Estill City	Dist-U	46.00	13.00	
7	Eutawville, Orangeburg County	Dist-U	115.00	24.90	
8	Fairfax Central, Fairfax City	Dist-U	46.00	13.09	
9	Five Points, Columbia City	Dist-U	115.00	8.75	
10	Fort Johnston Road, Charleston County	Dist-U	115.00	24.00	
11	Frogmore, Beaufort County	Dist-U	115.00	25.00	
12	Gardens Corner, Beaufort County	Dist-U	115.00	24.90	
13	Gaston, Lexington County	Dist-U	115.00	24.94	
14	Gilbert, Lexington County	Dist-U	115.00	24.94	
15	Grays Hill, Beaufort County	Dist-U	115.00	13.00	
16	Greengate, Richland County	Dist-U	115.00	24.94	
17	Grove Street, Charleston City	Dist-U	115.00	14.40	
18	Hampton, Hampton City	Dist-U	46.00	13.09	
19	Hanahan Switching, Berkeley County	Dist-U	46.00	4.16	
20	Harbison, Lexington County	Dist-U	115.00	24.94	
21	Hardeeville, Hardeeville City	Dist-U	115.00	24.90	
22	Hardeeville, Hardeeville City	Dist-U	43.80	13.09	
23	Herrin, Allendale County	Dist-U	46.00	13.09	
24	Holly Hill, Holly Hill City	Dist-U	115.00	24.94	
25	Houndslake, Aiken County	Dist-U	115.00	13.09	
26	Howard Street, Richland County	Dist-U	33.00	8.72	
27	Irmo Town, Irmo City	Dist-U	115.00	24.90	
28	Isle of Palms, Isle of Palms City	Dist-U	115.00	24.90	
29	Jackson 46-12KV, Aiken County	Dist-U	46.00	12.00	
30	Jackson Street, Columbia City	Dist-U	115.00	8.72	
31	James Island, Charleston County	Dist-U	115.00	24.90	
32	James Prioleau, Charleston County	Dist-U	115.00	25.00	
33	Jasper Construction, Jasper County	Dist-U	115.00	33.00	
34	Johnston 115-23KV, Edgefield County	Dist-U	115.00	24.90	
35	Kilbourne Park, Richland County	Dist-U	115.00	24.90	
36	Killian, Richland County	Dist-U	115.00	23.00	
37	Kingswood, Richland County	Dist-U	115.00	24.90	
38	Kronotex, Barnwell County	Dist-U	115.00	12.00	
39	Ladies Island, Beaufort County	Dist-U	115.00	24.90	
40	Lake Carolina, Richland County	Dist-U	115.00	25.00	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
45	2					1
65	2	1				2
28	1					3
22	1					4
14	1	1				5
14	1					6
50	2					7
18	2					8
22	1					9
50	2					10
28	1					11
22	1					12
50	2					13
22	1					14
22	1					15
37	1					16
22	1					17
18	2					18
14	2	1				19
50	2					20
28	1					21
21	2					22
11	1					23
60	5					24
28	1	1				25
11	1					26
28	1					27
50	2					28
11	1					29
22	1					30
45	2					31
28	1					32
11	1					33
22	1					34
60	2					35
37	1					36
45	2					37
28	1					38
50	2					39
65	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lake Murray Training, Lexington County	Dist-U	115.00	24.90	
2	Langley, Aiken County	Dist-U	115.00	13.09	
3	Leesville 115-23KV, Lexington County	Dist-U	115.00	24.90	
4	Lexington East Side, Lexington County	Dist-U	115.00	24.90	
5	Lexington Industrial Park, Lexington County	Dist-U	115.00	24.90	
6	Lexington West Side, Lexington County	Dist-U	115.00	23.90	
7	Lexington, Lexington County	Dist-U	115.00	23.00	
8	Lower Richland, Richland County	Dist-U	115.00	24.90	
9	Maryville, Charleston County	Dist-U	115.00	24.90	
10	McCormick City 115-13KV, McCormick County	Dist-U	115.00	13.09	
11	Meadowbook, Beaufort County	Dist-U	115.00	24.90	
12	Meeting Street, Charleston County	Dist-U	115.00	14.40	
13	Middleburg Mall, Richland County	Dist-U	115.00	8.72	
14	Midway, Union County	Dist-U	115.00	13.20	
15	Mt. Pleasant, Charleston County	Dist-U	115.00	24.90	
16	Muller Avenue, Richland County	Dist-U	115.00	8.70	
17	Muller Avenue, Richland County	Dist-U	115.00	24.90	
18	Naval Shipyard, Federal Property, SC	Dist-U	115.00	24.90	
19	Naval Shipyard, Federal Property, SC	Dist-U	115.00	13.80	
20	Neeses, Orangeburg County	Dist-U	46.00	8.70	
21	Network, Richland County	Dist-U	115.00	13.80	
22	North 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
23	North Augusta, Aiken City	Dist-U	115.00	13.09	
24	North Bridge Terrace, Charleston County	Dist-U	115.00	24.94	
25	North Naval Weapons, Federal Property	Dist-U	115.00	13.80	
26	North Rhett, North Charleston City	Dist-U	115.00	24.90	
27	Northpointe Business Park, Charleston County	Dist-U	115.00	23.00	
28	Northwoods Mall , North Charleston City	Dist-U	230.00	24.94	
29	Okatie, Jasper County	Dist-U	115.00	24.90	
30	Old Fort, Dorchester County	Dist-U	115.00	24.90	
31	Osceola Park, Charleston County	Dist-U	115.00	24.94	
32	Palmetto Commerce Park, Charleston City	Dist-U	115.00	24.90	
33	Park Street, Columbia City	Dist-U	33.00	13.20	
34	Parr 13.2-23KV, Fairfield County	Dist-U	24.90	13.80	
35	Pelion, Lexington County	Dist-U	115.00	24.90	
36	Pendleton Street, Columbia City	Dist-U	115.00	8.32	
37	Piney Woods Rd., Richland County	Dist-U	115.00	24.94	
38	Platts Springs Rd., Lexington County	Dist-U	115.00	24.90	
39	Platts Springs Rd., Lexington County	Dist-U	115.00	24.90	
40	Pontiac, Richland County	Dist-U	230.00	24.94	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
22	1					2
28	1					3
37	1					4
60	2	1				5
75	2	1				6
65	2	1				7
60	2					8
37	1					9
11	1	1				10
22	1	1				11
22	1					12
22	1					13
21	1					14
77	2					15
22	1					16
28	1					17
28	1					18
22	1					19
11	1					20
67	3					21
11	1					22
28	1					23
45	2					24
11	1					25
28	1					26
37	1					27
75	2	1				28
28	1					29
60	2					30
37	1					31
65	2					32
45	5					33
22	1					34
22	1	1				35
45	2					36
22	1					37
28	1					38
22	1					39
75	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Port Park, Hanahan City	Dist-U	115.00	24.94	
2	Port Royal, Port Royal City	Dist-U	115.00	13.09	
3	Pritchardville, Beaufort County	Dist-U	115.00	24.90	
4	Quail Hollow, Lexington County	Dist-U	115.00	24.94	
5	Raborn Pointe, North Augusta City	Dist-U	115.00	13.09	
6	Rantowles, Charleston County	Dist-U	115.00	24.90	
7	Red House Rd., Charleston County	Dist-U	43.80	24.90	
8	Richland Mall, Forest Acres City	Dist-U	115.00	8.32	
9	Ridgeland, Jasper County	Dist-U	115.00	24.90	
10	Riverland Terrace, Charleston County	Dist-U	115.00	24.90	
11	Riverland Terrace, Charleston County	Dist-U	24.90	4.16	
12	Rosewood, Columbia City	Dist-U	33.00	8.30	
13	S.C. Research Assoc., Richland County	Dist-U	115.00	24.90	
14	Sage Mill Industrial Park, Aiken County	Dist-U	115.00	13.09	
15	Saluda County, Saluda County	Dist-U	115.00	24.94	
16	Sandhill, Richland County	Dist-U	115.00	24.94	
17	Santee, Orangeburg County	Dist-U	46.00	8.70	
18	Savage Road, Charleston County	Dist-U	115.00	24.90	
19	Saxe Gotha Industrial Park, Lexington County	Dist-U	115.00	23.00	
20	Seven Mile, North Charleston City	Dist-U	115.00	24.90	
21	Shell Point, Beaufort County	Dist-U	43.80	13.09	
22	Silver Bluff Rd., Aiken County	Dist-U	115.00	13.09	
23	S-Lubeca, Richland County	Dist-U	115.00	12.00	
24	South Main, Columbia City	Dist-U	115.00	8.72	
25	Sparkleberry, Richland County	Dist-U	115.00	24.94	
26	Sparkleberry, Richland County	Dist-U	115.00	37.30	
27	Springdale, Lexington County	Dist-U	115.00	24.94	
28	St. George, Dorchester County	Dist-U	115.00	13.09	
29	St. Helena Island, Beaufort County	Dist-U	115.00	24.94	
30	St. Matthews, Calhoun County	Dist-U	43.80	24.94	
31	Stono Park, Charleston City	Dist-U	115.00	24.94	
32	Summer Construction, Fairfield County	Dist-U	115.00	24.94	
33	Summerville Central, Berkeley County	Dist-U	115.00	24.94	
34	Summerville Industrial Park, Dorchester County	Dist-U	115.00	24.94	
35	Summerville Plaza, City of Summerville	Dist-U	115.00	24.94	
36	Summerville-Ladson, Charleston County	Dist-U	115.00	24.94	
37	Swansea, Lexington County	Dist-U	46.00	23.00	
38	Sweetwater, Aiken County	Dist-U	115.00	13.09	
39	Ten Mile, Charleston County	Dist-U	115.00	24.90	
40	Terminal, Richland County	Dist-U	33.00	8.72	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
22	1					1
28	1					2
28	1					3
37	1	2				4
22	1					5
28	1					6
45	2	1				7
45	2					8
22	1	1				9
22	1					10
4	1					11
21	2					12
22	1					13
28	1					14
22	1					15
75	2					16
11	1					17
45	2					18
37	1					19
22	1					20
25	2					21
22	1					22
22	1					23
22	1					24
38	1					25
37	1					26
45	2	1				27
28	1					28
50	2					29
23	2	1				30
37	1					31
22	1					32
40	1					33
50	2					34
37	1					35
60	2					36
11	1	1				37
22	1					38
22	1					39
11	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Timberlake, Lexington County	Dist-U	230.00	24.94	
2	Uptown, Columbia City	Dist-U	115.00	24.90	
3	Uptown, Columbia City	Dist-U	115.00	8.72	
4	Varnville, Varnville City	Dist-U	46.00	13.09	
5	Victory Gardens, Columbia City	Dist-U	115.00	8.32	
6	Wagener, Wagener City	Dist-U	46.00	8.32	
7	Walterboro 115-23KV, Walterboro City	Dist-U	115.00	24.90	
8	Walterboro-Forest Hill, Walterboro City	Dist-U	115.00	24.94	
9	Walterboro Industrial Park, Walterboro City	Dist-U	115.00	24.94	
10	Walterboro Southside, Walterboro City	Dist-U	115.00	24.94	
11	West Columbia, West Columbia City	Dist-U	33.00	8.32	
12	White Gables, Dorchester County	Dist-U	115.00	25.00	
13	White Rock, Richland County	Dist-U	115.00	24.90	
14	Whitehall, Lexington County	Dist-U	115.00	24.90	
15	Williston, Williston City	Dist-U	115.00	13.09	
16	Winnsboro, Winnsboro City	Dist-U	115.00	24.90	
17	Woodfield Park, Richland County	Dist-U	115.00	24.94	
18	Yemassee Central, Yemassee City	Dist-U	115.00	24.90	
19					
20	Distribution Substations				
21	Under 10,000 KVA (38)	Dist-U			
22					
23	Functional Summary of Capacity				
24	Transmission Substations				
25	Distribution Substations				
26					
27					
28					
29					
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32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
37	1	1				1
37	1	1				2
23	1					3
11	1					4
22	1					5
11	1					6
22	1					7
40	1					8
28	1					9
22	1					10
18	2					11
37	1					12
50	2	1				13
22	1					14
22	1					15
45	2					16
45	2					17
22	1					18
						19
6488						20
212						21
						22
						23
20558						24
6700						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.7 Line No.: 21 Column: c

Various

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Natural Gas Transportation and Demand	CGT	803/547	29,971,709
3	Natural Gas Commodity and Demand	SEMI	803/547	195,720,596
4	Coal Purchases	Canadys Refined Coal, LLC	419	120,419,896
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6				
7				
8				
9				
10				
11				
12				
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14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Rental Fee for Use of Assets	SCANA Services	454/493	5,624,583
22	Rental Fee for Use of Facilities	CGT	454/493	1,071,056
23	Fleet Vehicle Services	CGT	Various	594,726
24	Coal Sales	Canadys Refined Coal, LLC	419	119,782,895
25				
26				
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42				

Schedule Page: 429 Line No.: 2 Column: b

See page 102 for definition of abbreviations used for Affiliated Companies.

Schedule Page: 429 Line No.: 4 Column: b

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and selling of refined coal to reduce emissions.

Schedule Page: 429 Line No.: 8 Column: a

The transactions below represent activities billed by SCANA Services, Inc. to SCE&G during the reporting period.

REPORTING BUSINESS UNIT	Category	FERC Account	Direct Billed	Allocated	Total Billed
SCEG	Corporate Security	1070	408,275	14,851	423,126
SCEG	Corporate Security	1080	483,525	0	483,525
SCEG	Corporate Security	1180	112,549	1,599	114,148
SCEG	Corporate Security	1190	1,011	0	1,011
SCEG	Corporate Security	1210	7,027	0	7,027
SCEG	Corporate Security	1823	59,563	0	59,563
SCEG	Corporate Security	1840	42	0	42
SCEG	Corporate Security	1860	0	15,513	15,513
SCEG	Corporate Security	4081	207,632	17,175	224,807
SCEG	Corporate Security	4210	0	2,975	2,975
SCEG	Corporate Security	4265	67,186	8,781	75,967
SCEG	Corporate Security	5660	299	0	299
SCEG	Corporate Security	5700	556	0	556
SCEG	Corporate Security	5710	33,881	0	33,881
SCEG	Corporate Security	5930	100,671	0	100,671
SCEG	Corporate Security	9030	94	0	94
SCEG	Corporate Security	9040	(2,663)	0	(2,663)
SCEG	Corporate Security	9050	1,385	0	1,385
SCEG	Corporate Security	9120	533	0	533
SCEG	Corporate Security	9200	2,822,165	239,773	3,061,938
SCEG	Corporate Security	9210	679,289	77,278	756,567
SCEG	Corporate Security	9230	4,214,627	223,465	4,438,092
SCEG	Corporate Security	9250	11,072	383	11,455
SCEG	Corporate Security	9260	714,487	112,445	826,932
SCEG	Corporate Security	9310	36,303	4,722	41,025
SCEG	Corporate Security	9350	8,326	2,674	11,000
SCEG	Customer Services & Operational Support	1070	1,322,483	69,639	1,392,122
SCEG	Customer Services & Operational Support	1180	1,028,672	7,502	1,036,174
SCEG	Customer Services & Operational Support	1630	9,667	0	9,667
SCEG	Customer Services & Operational Support	1823	33,363	0	33,363
SCEG	Customer Services & Operational Support	1840	325,144	0	325,144
SCEG	Customer Services & Operational Support	1860	3,346	72,493	75,839
SCEG	Customer Services & Operational Support	4081	894,658	74,222	968,880
SCEG	Customer Services & Operational Support	4082	2,928	1,359	4,287
SCEG	Customer Services & Operational Support	4160	59,603	14,438	74,041

SCEG	Customer Services & Operational Support	4171	15,234	5,001	20,235
SCEG	Customer Services & Operational Support	4210	0	13,904	13,904
SCEG	Customer Services & Operational Support	4261	4,402	195	4,597
SCEG	Customer Services & Operational Support	4265	10,873	3,726	14,599
SCEG	Customer Services & Operational Support	5370	2,579	0	2,579
SCEG	Customer Services & Operational Support	5710	3,012	0	3,012
SCEG	Customer Services & Operational Support	5800	34,893	0	34,893
SCEG	Customer Services & Operational Support	5880	347,402	0	347,402
SCEG	Customer Services & Operational Support	5930	9,341	0	9,341
SCEG	Customer Services & Operational Support	8630	0	351	351
SCEG	Customer Services & Operational Support	8700	282	0	282
SCEG	Customer Services & Operational Support	8740	193,102	705	193,807
SCEG	Customer Services & Operational Support	8780	0	0	0
SCEG	Customer Services & Operational Support	8790	0	0	0
SCEG	Customer Services & Operational Support	9010	1,169,996	0	1,169,996
SCEG	Customer Services & Operational Support	9020	31,236	0	31,236
SCEG	Customer Services & Operational Support	9030	14,760,448	1,070,914	15,831,362
SCEG	Customer Services & Operational Support	9050	1,924,032	(13,258)	1,910,774
SCEG	Customer Services & Operational Support	9070	151	0	151
SCEG	Customer Services & Operational Support	9080	77,029	0	77,029
SCEG	Customer Services & Operational Support	9200	1,026,448	58,744	1,085,192
SCEG	Customer Services & Operational Support	9210	1,244,795	3,653	1,248,448
SCEG	Customer Services & Operational Support	9230	67,669	596	68,265
SCEG	Customer Services & Operational Support	9260	3,014,685	504,717	3,519,402
SCEG	Customer Services & Operational Support	9300	0	0	0
SCEG	Customer Services & Operational Support	9301	53,500	0	53,500
SCEG	Customer Services & Operational Support	9302	2,871	0	2,871
SCEG	Customer Services & Operational Support	9310	2,757	38,648	41,405
SCEG	Customer Services & Operational Support	9350	19,244	642	19,886
SCEG	Employee Services	1070	2,337,624	1,038,851	3,376,475
SCEG	Employee Services	1080	1,905	0	1,905
SCEG	Employee Services	1180	4,731,958	119,123	4,851,081
SCEG	Employee Services	1540	5,982	0	5,982
SCEG	Employee Services	1630	2,200	0	2,200
SCEG	Employee Services	1823	22,758	0	22,758
SCEG	Employee Services	1840	59,307	0	59,307
SCEG	Employee Services	1860	618	31,675	32,293
SCEG	Employee Services	4081	875,543	249,626	1,125,169
SCEG	Employee Services	4082	1,126	17,475	18,601
SCEG	Employee Services	4160	2,315	2,689	5,004
SCEG	Employee Services	4171	4,308	59,218	63,526
SCEG	Employee Services	4210	0	6,075	6,075
SCEG	Employee Services	4261	0	3,986	3,986
SCEG	Employee Services	4264	4,420	0	4,420
SCEG	Employee Services	4265	37,330	894,853	932,183

SCEG	Employee Services	5000	50	0	50
SCEG	Employee Services	5010	126	0	126
SCEG	Employee Services	5020	50	0	50
SCEG	Employee Services	5060	362	0	362
SCEG	Employee Services	5110	188	0	188
SCEG	Employee Services	5240	185,147	0	185,147
SCEG	Employee Services	5350	4	0	4
SCEG	Employee Services	5370	3,451	0	3,451
SCEG	Employee Services	5390	75	0	75
SCEG	Employee Services	5440	376	0	376
SCEG	Employee Services	5480	188	0	188
SCEG	Employee Services	5490	87	0	87
SCEG	Employee Services	5530	1,073	0	1,073
SCEG	Employee Services	5540	188	0	188
SCEG	Employee Services	5550	0	0	0
SCEG	Employee Services	5560	485	0	485
SCEG	Employee Services	5660	995	0	995
SCEG	Employee Services	5700	291	0	291
SCEG	Employee Services	5710	434	0	434
SCEG	Employee Services	5830	193	0	193
SCEG	Employee Services	5850	405	0	405
SCEG	Employee Services	5880	44,605	0	44,605
SCEG	Employee Services	5920	763	0	763
SCEG	Employee Services	5930	1,848	0	1,848
SCEG	Employee Services	5970	604	0	604
SCEG	Employee Services	8410	212	0	212
SCEG	Employee Services	8700	61,827	4,999	66,826
SCEG	Employee Services	8740	64,279	50,628	114,907
SCEG	Employee Services	8780	15	0	15
SCEG	Employee Services	8790	394	0	394
SCEG	Employee Services	8800	13,443	644	14,087
SCEG	Employee Services	8850	15	0	15
SCEG	Employee Services	8870	99,927	1,266	101,193
SCEG	Employee Services	9010	0	1,603	1,603
SCEG	Employee Services	9020	70	0	70
SCEG	Employee Services	9030	341,401	20,456	361,857
SCEG	Employee Services	9050	13,593	0	13,593
SCEG	Employee Services	9080	12,676	0	12,676
SCEG	Employee Services	9100	95,366	188,702	284,068
SCEG	Employee Services	9120	3,046	0	3,046
SCEG	Employee Services	9160	142	0	142
SCEG	Employee Services	9200	20,285,289	2,524,653	22,809,942
SCEG	Employee Services	9210	347,459	572,791	920,250
SCEG	Employee Services	9230	23,653	432,133	455,786
SCEG	Employee Services	9250	851,059	38,428	889,487

SCEG	Employee Services	9260	887,522	856,190	1,743,712
SCEG	Employee Services	9302	1,655	95,154	96,809
SCEG	Employee Services	9310	11,789	18,960	30,749
SCEG	Employee Services	9350	9,830	3,064	12,894
SCEG	Environmental Services	1070	384,690	11,886	396,576
SCEG	Environmental Services	1080	1,160,097	0	1,160,097
SCEG	Environmental Services	1180	88,881	1,280	90,161
SCEG	Environmental Services	1190	117,553	0	117,553
SCEG	Environmental Services	1830	6,125	0	6,125
SCEG	Environmental Services	1840	94,364	0	94,364
SCEG	Environmental Services	1860	61,729	12,416	74,145
SCEG	Environmental Services	4081	135,683	15,325	151,008
SCEG	Environmental Services	4082	9,234	634	9,868
SCEG	Environmental Services	4171	33,818	2,046	35,864
SCEG	Environmental Services	4210	0	2,381	2,381
SCEG	Environmental Services	4261	26,778	0	26,778
SCEG	Environmental Services	4265	22,653	24,164	46,817
SCEG	Environmental Services	5060	3,456	0	3,456
SCEG	Environmental Services	5100	40	0	40
SCEG	Environmental Services	5240	1,728	0	1,728
SCEG	Environmental Services	5390	3,456	0	3,456
SCEG	Environmental Services	5490	576	0	576
SCEG	Environmental Services	5660	28,222	0	28,222
SCEG	Environmental Services	5880	16,703	0	16,703
SCEG	Environmental Services	5920	58,392	0	58,392
SCEG	Environmental Services	7350	1,185,966	0	1,185,966
SCEG	Environmental Services	8400	0	1,557	1,557
SCEG	Environmental Services	9110	68	0	68
SCEG	Environmental Services	9200	1,367,230	208,184	1,575,414
SCEG	Environmental Services	9210	291,361	76,784	368,145
SCEG	Environmental Services	9230	614,206	141,906	756,112
SCEG	Environmental Services	9260	481,536	94,655	576,191
SCEG	Environmental Services	9302	61,292	0	61,292
SCEG	Environmental Services	9310	2,672	0	2,672
SCEG	Environmental Services	9350	402,015	19	402,034
SCEG	Executive Services	1070	1,271,637	15,998	1,287,635
SCEG	Executive Services	1180	0	1,723	1,723
SCEG	Executive Services	1823	65,402	0	65,402
SCEG	Executive Services	1840	211,017	0	211,017
SCEG	Executive Services	1860	915	16,711	17,626
SCEG	Executive Services	4081	72,713	104,372	177,085
SCEG	Executive Services	4082	267	19,785	20,052
SCEG	Executive Services	4171	1,081	68,582	69,663
SCEG	Executive Services	4210	0	3,205	3,205
SCEG	Executive Services	4261	0	36,120	36,120

SCEG	Executive Services	4264	147,207	23	147,230
SCEG	Executive Services	4265	70,089	587,269	657,358
SCEG	Executive Services	5170	77,607	0	77,607
SCEG	Executive Services	5240	4,984	0	4,984
SCEG	Executive Services	5280	3,339	0	3,339
SCEG	Executive Services	5660	78,595	0	78,595
SCEG	Executive Services	5710	83,832	0	83,832
SCEG	Executive Services	5880	10,959	0	10,959
SCEG	Executive Services	5930	247,128	0	247,128
SCEG	Executive Services	9010	9,050	0	9,050
SCEG	Executive Services	9050	64	0	64
SCEG	Executive Services	9200	821,445	1,457,734	2,279,179
SCEG	Executive Services	9210	446,892	169,453	616,345
SCEG	Executive Services	9260	258,700	417,389	676,089
SCEG	Executive Services	9280	89	0	89
SCEG	Executive Services	9302	778,500	0	778,500
SCEG	Executive Services	9310	0	3,180	3,180
SCEG	Executive Services	9350	86,728	0	86,728
SCEG	Financial Services	1070	16,663,534	320,319	16,983,853
SCEG	Financial Services	1080	46	0	46
SCEG	Financial Services	1180	4,916,802	35,426	4,952,228
SCEG	Financial Services	1630	(411)	0	(411)
SCEG	Financial Services	1823	929,998	0	929,998
SCEG	Financial Services	1840	83,293	0	83,293
SCEG	Financial Services	1860	119,612	43,972	163,584
SCEG	Financial Services	4081	241,226	4,084,804	4,326,030
SCEG	Financial Services	4082	9,081	220,822	229,903
SCEG	Financial Services	4140	0	11,292,248	11,292,248
SCEG	Financial Services	4160	6,960	178,256	185,216
SCEG	Financial Services	4171	5,989	5,054	11,043
SCEG	Financial Services	4210	0	8,434	8,434
SCEG	Financial Services	4261	320	17,529	17,849
SCEG	Financial Services	4264	(294)	2,433	2,139
SCEG	Financial Services	4265	111,255	153,661	264,916
SCEG	Financial Services	4270	12,804	0	12,804
SCEG	Financial Services	4300	0	6,488,908	6,488,908
SCEG	Financial Services	4320	0	(2,834)	(2,834)
SCEG	Financial Services	5240	(51,983)	0	(51,983)
SCEG	Financial Services	5560	83,437	0	83,437
SCEG	Financial Services	5880	710	0	710
SCEG	Financial Services	5920	(51,783)	0	(51,783)
SCEG	Financial Services	7350	(883,428)	0	(883,428)
SCEG	Financial Services	8740	0	2,034	2,034
SCEG	Financial Services	9030	364,521	51,685	416,206
SCEG	Financial Services	9050	491	0	491

SCEG	Financial Services	9080	378	0	378
SCEG	Financial Services	9200	2,765,286	3,691,631	6,456,917
SCEG	Financial Services	9210	106,564	319,670	426,234
SCEG	Financial Services	9230	2,138,802	2,377,428	4,516,230
SCEG	Financial Services	9240	(362,551)	325,009	(37,542)
SCEG	Financial Services	9250	1,296,631	19,974	1,316,605
SCEG	Financial Services	9260	974,848	1,163,169	2,138,017
SCEG	Financial Services	9280	4,845	0	4,845
SCEG	Financial Services	9302	0	205,499	205,499
SCEG	Financial Services	9310	13,822	6,459	20,281
SCEG	Financial Services	9350	467,182	180,883	648,065
SCEG	Gas Control Coordination & Gas Engineering Services	1070	0	5,989	5,989
SCEG	Gas Control Coordination & Gas Engineering Services	1180	361,767	645	362,412
SCEG	Gas Control Coordination & Gas Engineering Services	1190	138	0	138
SCEG	Gas Control Coordination & Gas Engineering Services	1823	172,185	0	172,185
SCEG	Gas Control Coordination & Gas Engineering Services	1860	13,403	6,256	19,659
SCEG	Gas Control Coordination & Gas Engineering Services	4081	41,865	32,571	74,436
SCEG	Gas Control Coordination & Gas Engineering Services	4210	0	1,200	1,200
SCEG	Gas Control Coordination & Gas Engineering Services	4265	121	39	160
SCEG	Gas Control Coordination & Gas Engineering Services	8400	83,421	2,035	85,456
SCEG	Gas Control Coordination & Gas Engineering Services	8410	3,390	279	3,669
SCEG	Gas Control Coordination & Gas Engineering Services	8610	0	3,328	3,328
SCEG	Gas Control Coordination & Gas Engineering Services	8630	0	844	844
SCEG	Gas Control Coordination & Gas Engineering Services	8700	298,578	136,973	435,551
SCEG	Gas Control Coordination & Gas Engineering Services	8740	76,788	319,735	396,523
SCEG	Gas Control Coordination & Gas Engineering Services	8800	44,007	2,246	46,253
SCEG	Gas Control Coordination & Gas Engineering Services	8850	5,095	308	5,403
SCEG	Gas Control Coordination & Gas Engineering Services	8870	394,304	97	394,401
SCEG	Gas Control Coordination & Gas Engineering Services	9100	216,867	0	216,867

SCEG	Gas Control Coordination & Gas Engineering Services	9120	0	1,825	1,825
SCEG	Gas Control Coordination & Gas Engineering Services	9200	235,971	20,897	256,868
SCEG	Gas Control Coordination & Gas Engineering Services	9210	5,061	16,061	21,122
SCEG	Gas Control Coordination & Gas Engineering Services	9230	1,569	226	1,795
SCEG	Gas Control Coordination & Gas Engineering Services	9260	149,377	142,006	291,383
SCEG	Gas Control Coordination & Gas Engineering Services	9302	112,836	0	112,836
SCEG	Gas Measurement Services	1070	0	2,046	2,046
SCEG	Gas Measurement Services	1180	1,033,819	220	1,034,039
SCEG	Gas Measurement Services	1630	83,646	0	83,646
SCEG	Gas Measurement Services	1860	0	2,137	2,137
SCEG	Gas Measurement Services	4081	9,883	3,638	13,521
SCEG	Gas Measurement Services	4210	0	410	410
SCEG	Gas Measurement Services	8700	23,777	275	24,052
SCEG	Gas Measurement Services	8740	465	35	500
SCEG	Gas Measurement Services	8750	0	1,003	1,003
SCEG	Gas Measurement Services	8800	18,665	2,491	21,156
SCEG	Gas Measurement Services	8850	129	0	129
SCEG	Gas Measurement Services	8900	0	(570)	(570)
SCEG	Gas Measurement Services	8930	94,817	65,411	160,228
SCEG	Gas Measurement Services	9200	3,411	49,538	52,949
SCEG	Gas Measurement Services	9210	3,222	1,447	4,669
SCEG	Gas Measurement Services	9230	636	1,647	2,283
SCEG	Gas Measurement Services	9260	33,262	19,862	53,124
SCEG	Gas Measurement Services	9310	0	127,527	127,527
SCEG	Gas Supply and Fuel Procurement	1070	0	3,222	3,222
SCEG	Gas Supply and Fuel Procurement	1180	0	347	347
SCEG	Gas Supply and Fuel Procurement	1860	0	3,365	3,365
SCEG	Gas Supply and Fuel Procurement	4081	31,167	17,831	48,998
SCEG	Gas Supply and Fuel Procurement	4210	0	645	645
SCEG	Gas Supply and Fuel Procurement	4265	0	4,105	4,105
SCEG	Gas Supply and Fuel Procurement	5170	176	0	176
SCEG	Gas Supply and Fuel Procurement	5240	20,774	0	20,774
SCEG	Gas Supply and Fuel Procurement	9200	422,512	240,060	662,572
SCEG	Gas Supply and Fuel Procurement	9210	31,842	84,515	116,357
SCEG	Gas Supply and Fuel Procurement	9260	114,127	71,259	185,386
SCEG	Information Services	1070	12,278,415	1,126,352	13,404,767
SCEG	Information Services	1080	44,376	0	44,376
SCEG	Information Services	1180	2,394,069	110,224	2,504,293
SCEG	Information Services	1210	(56,598)	0	(56,598)
SCEG	Information Services	1630	189,903	0	189,903

SCEG	Information Services	1822	11,829	0	11,829
SCEG	Information Services	1823	643,768	0	643,768
SCEG	Information Services	1840	365,032	0	365,032
SCEG	Information Services	1860	1,136	9,847	10,983
SCEG	Information Services	2270	116,278	0	116,278
SCEG	Information Services	2430	(59,680)	0	(59,680)
SCEG	Information Services	4081	93,039	18,576	111,615
SCEG	Information Services	4082	10,711	115	10,826
SCEG	Information Services	4140	0	105,606	105,606
SCEG	Information Services	4160	59,370	8,394	67,764
SCEG	Information Services	4171	309,525	2,053	311,578
SCEG	Information Services	4210	0	1,889	1,889
SCEG	Information Services	4261	0	14,919	14,919
SCEG	Information Services	4264	0	1,802	1,802
SCEG	Information Services	4265	175,305	121,015	296,320
SCEG	Information Services	5000	10,307	0	10,307
SCEG	Information Services	5010	11,638	0	11,638
SCEG	Information Services	5060	542,461	0	542,461
SCEG	Information Services	5140	472	0	472
SCEG	Information Services	5170	12,906	0	12,906
SCEG	Information Services	5190	42,452	0	42,452
SCEG	Information Services	5200	341,183	0	341,183
SCEG	Information Services	5240	4,868,884	0	4,868,884
SCEG	Information Services	5280	1,412	0	1,412
SCEG	Information Services	5290	53,017	0	53,017
SCEG	Information Services	5300	3,186	0	3,186
SCEG	Information Services	5320	1,360,864	0	1,360,864
SCEG	Information Services	5350	13,726	0	13,726
SCEG	Information Services	5370	14,196	0	14,196
SCEG	Information Services	5380	2,158	0	2,158
SCEG	Information Services	5390	135,273	0	135,273
SCEG	Information Services	5440	644	0	644
SCEG	Information Services	5460	6,864	0	6,864
SCEG	Information Services	5480	1,244	0	1,244
SCEG	Information Services	5490	110,934	0	110,934
SCEG	Information Services	5560	197,035	0	197,035
SCEG	Information Services	5600	37,031	0	37,031
SCEG	Information Services	5611	9,115	0	9,115
SCEG	Information Services	5612	38,511	0	38,511
SCEG	Information Services	5620	153,636	0	153,636
SCEG	Information Services	5630	2,447	0	2,447
SCEG	Information Services	5660	556,717	0	556,717
SCEG	Information Services	5680	27,017	0	27,017
SCEG	Information Services	5700	147,047	0	147,047
SCEG	Information Services	5710	7,368	0	7,368

SCEG	Information Services	5730	59,321	0	59,321
SCEG	Information Services	5800	3,366	0	3,366
SCEG	Information Services	5810	4,275	0	4,275
SCEG	Information Services	5820	152,051	0	152,051
SCEG	Information Services	5830	11,637	0	11,637
SCEG	Information Services	5840	108	0	108
SCEG	Information Services	5860	12,252	0	12,252
SCEG	Information Services	5880	1,035,255	0	1,035,255
SCEG	Information Services	5900	696	0	696
SCEG	Information Services	5920	49,224	0	49,224
SCEG	Information Services	5930	86,980	0	86,980
SCEG	Information Services	5940	49,479	0	49,479
SCEG	Information Services	5950	1,369	0	1,369
SCEG	Information Services	5960	7,267	0	7,267
SCEG	Information Services	5970	57,715	0	57,715
SCEG	Information Services	5980	2,282	0	2,282
SCEG	Information Services	7350	339	0	339
SCEG	Information Services	8410	12,148	0	12,148
SCEG	Information Services	8439	199,165	0	199,165
SCEG	Information Services	8700	14,275	0	14,275
SCEG	Information Services	8710	1,947	0	1,947
SCEG	Information Services	8740	126,577	0	126,577
SCEG	Information Services	8750	65,727	0	65,727
SCEG	Information Services	8760	73,312	0	73,312
SCEG	Information Services	8780	30,968	0	30,968
SCEG	Information Services	8790	31,529	0	31,529
SCEG	Information Services	8800	336,827	0	336,827
SCEG	Information Services	8870	6,997	0	6,997
SCEG	Information Services	8900	988	0	988
SCEG	Information Services	8920	6,516	0	6,516
SCEG	Information Services	8930	9,045	0	9,045
SCEG	Information Services	8940	716	0	716
SCEG	Information Services	9010	25,263	0	25,263
SCEG	Information Services	9020	337,833	208,448	546,281
SCEG	Information Services	9030	15,125,991	172,195	15,298,186
SCEG	Information Services	9050	657,530	7,035	664,565
SCEG	Information Services	9070	2,688	0	2,688
SCEG	Information Services	9080	161,010	0	161,010
SCEG	Information Services	9100	26,516	0	26,516
SCEG	Information Services	9110	4,527	0	4,527
SCEG	Information Services	9120	181,970	(256)	181,714
SCEG	Information Services	9160	79,310	286,037	365,347
SCEG	Information Services	9200	549,619	249,479	799,098
SCEG	Information Services	9210	9,615,798	4,761,011	14,376,809
SCEG	Information Services	9230	0	0	0

SCEG	Information Services	9260	303,129	96,790	399,919
SCEG	Information Services	9301	265	0	265
SCEG	Information Services	9302	400,533	12,558	413,091
SCEG	Information Services	9310	384,652	58,113	442,765
SCEG	Information Services	9350	1,318,387	217,019	1,535,406
SCEG	Land & Facilities Management	1070	4,430,194	66,498	4,496,692
SCEG	Land & Facilities Management	1080	2,142,402	0	2,142,402
SCEG	Land & Facilities Management	1180	1,016,118	7,576	1,023,694
SCEG	Land & Facilities Management	1190	219,393	0	219,393
SCEG	Land & Facilities Management	1210	4,932,823	0	4,932,823
SCEG	Land & Facilities Management	1630	14,481	0	14,481
SCEG	Land & Facilities Management	1823	9,283	0	9,283
SCEG	Land & Facilities Management	1840	127,907	0	127,907
SCEG	Land & Facilities Management	1860	(1,984,528)	9,238	(1,975,290)
SCEG	Land & Facilities Management	4081	49,248	33,304	82,552
SCEG	Land & Facilities Management	4082	14,038	1,636	15,674
SCEG	Land & Facilities Management	4160	4,936	0	4,936
SCEG	Land & Facilities Management	4171	43,567	5,968	49,535
SCEG	Land & Facilities Management	4210	0	1,772	1,772
SCEG	Land & Facilities Management	4261	40,046	0	40,046
SCEG	Land & Facilities Management	4265	442,709	32,948	475,657
SCEG	Land & Facilities Management	5000	630	0	630
SCEG	Land & Facilities Management	5010	1,151,659	0	1,151,659
SCEG	Land & Facilities Management	5060	48,752	0	48,752
SCEG	Land & Facilities Management	5110	68,729	0	68,729
SCEG	Land & Facilities Management	5120	101,672	0	101,672
SCEG	Land & Facilities Management	5140	3,349	0	3,349
SCEG	Land & Facilities Management	5170	19,868	0	19,868
SCEG	Land & Facilities Management	5200	11,387	0	11,387
SCEG	Land & Facilities Management	5240	53,672	0	53,672
SCEG	Land & Facilities Management	5290	606,683	0	606,683
SCEG	Land & Facilities Management	5300	5,135	0	5,135
SCEG	Land & Facilities Management	5320	27,005	0	27,005
SCEG	Land & Facilities Management	5370	82,588	0	82,588
SCEG	Land & Facilities Management	5390	41,024	0	41,024
SCEG	Land & Facilities Management	5430	2,136	0	2,136
SCEG	Land & Facilities Management	5440	2,981	0	2,981
SCEG	Land & Facilities Management	5450	8,306	0	8,306
SCEG	Land & Facilities Management	5460	2,191	0	2,191
SCEG	Land & Facilities Management	5490	77,433	0	77,433
SCEG	Land & Facilities Management	5510	5,743	0	5,743
SCEG	Land & Facilities Management	5520	8,181	0	8,181
SCEG	Land & Facilities Management	5530	11,549	0	11,549
SCEG	Land & Facilities Management	5560	38,600	0	38,600
SCEG	Land & Facilities Management	5600	8,726	0	8,726

SCEG	Land & Facilities Management	5660	240,125	0	240,125
SCEG	Land & Facilities Management	5690	21,827	0	21,827
SCEG	Land & Facilities Management	5700	25,203	0	25,203
SCEG	Land & Facilities Management	5710	1,564	0	1,564
SCEG	Land & Facilities Management	5720	355	0	355
SCEG	Land & Facilities Management	5800	9,250	0	9,250
SCEG	Land & Facilities Management	5820	116	0	116
SCEG	Land & Facilities Management	5830	436	0	436
SCEG	Land & Facilities Management	5860	2,642	0	2,642
SCEG	Land & Facilities Management	5880	44,809	0	44,809
SCEG	Land & Facilities Management	5890	275,281	0	275,281
SCEG	Land & Facilities Management	5900	1,854	0	1,854
SCEG	Land & Facilities Management	5910	1,200	0	1,200
SCEG	Land & Facilities Management	5920	144,210	0	144,210
SCEG	Land & Facilities Management	5930	4,528	0	4,528
SCEG	Land & Facilities Management	5940	34	0	34
SCEG	Land & Facilities Management	5970	5,991	0	5,991
SCEG	Land & Facilities Management	5980	8,674	0	8,674
SCEG	Land & Facilities Management	7350	0	0	0
SCEG	Land & Facilities Management	8410	1,953	0	1,953
SCEG	Land & Facilities Management	8432	19,043	0	19,043
SCEG	Land & Facilities Management	8439	65,683	0	65,683
SCEG	Land & Facilities Management	8700	845	0	845
SCEG	Land & Facilities Management	8740	1,043	0	1,043
SCEG	Land & Facilities Management	8750	242	0	242
SCEG	Land & Facilities Management	8810	173,642	0	173,642
SCEG	Land & Facilities Management	8870	7,333	0	7,333
SCEG	Land & Facilities Management	8890	2,760	0	2,760
SCEG	Land & Facilities Management	8900	1,047	0	1,047
SCEG	Land & Facilities Management	8920	987	0	987
SCEG	Land & Facilities Management	8940	1,347	0	1,347
SCEG	Land & Facilities Management	9020	8,039	0	8,039
SCEG	Land & Facilities Management	9030	6,192	0	6,192
SCEG	Land & Facilities Management	9050	2,028	0	2,028
SCEG	Land & Facilities Management	9080	4,491	0	4,491
SCEG	Land & Facilities Management	9100	1,714	0	1,714
SCEG	Land & Facilities Management	9120	8,410	0	8,410
SCEG	Land & Facilities Management	9160	60	0	60
SCEG	Land & Facilities Management	9200	126,525	78,076	204,601
SCEG	Land & Facilities Management	9210	238,462	26,447	264,909
SCEG	Land & Facilities Management	9230	0	0	0
SCEG	Land & Facilities Management	9260	111,356	138,965	250,321
SCEG	Land & Facilities Management	9302	2,751	0	2,751
SCEG	Land & Facilities Management	9310	3,707,255	668,777	4,376,032
SCEG	Land & Facilities Management	9350	2,919,732	1,954,832	4,874,564

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2014/Q4

FOOTNOTE DATA

SCEG	Legal	1070	1,350,844	19,765	1,370,609
SCEG	Legal	1180	51,030	2,129	53,159
SCEG	Legal	1210	34,167	0	34,167
SCEG	Legal	1823	(82,572)	0	(82,572)
SCEG	Legal	1830	17,224	0	17,224
SCEG	Legal	1860	118,312	20,646	138,958
SCEG	Legal	4081	124,641	146,379	271,020
SCEG	Legal	4082	1,817	131	1,948
SCEG	Legal	4160	43,508	0	43,508
SCEG	Legal	4171	6,233	541	6,774
SCEG	Legal	4210	0	3,960	3,960
SCEG	Legal	4261	112	0	112
SCEG	Legal	4265	21,398	131,065	152,463
SCEG	Legal	5710	19,574	0	19,574
SCEG	Legal	5930	57,703	0	57,703
SCEG	Legal	7350	18,257	0	18,257
SCEG	Legal	8740	4,892	0	4,892
SCEG	Legal	9040	(100)	0	(100)
SCEG	Legal	9120	2,338	0	2,338
SCEG	Legal	9200	1,348,258	1,978,236	3,326,494
SCEG	Legal	9210	(44,045)	176,989	132,944
SCEG	Legal	9230	3,810,878	1,299,004	5,109,882
SCEG	Legal	9250	1,058,717	12,577	1,071,294
SCEG	Legal	9260	441,792	575,509	1,017,301
SCEG	Legal	9280	253,558	0	253,558
SCEG	Legal	9302	0	1,465,128	1,465,128
SCEG	Legal	9310	3,622	0	3,622
SCEG	Legal	9350	1,296	0	1,296
SCEG	Marketing & Sales	1070	21,067	9,411	30,478
SCEG	Marketing & Sales	1180	919	1,014	1,933
SCEG	Marketing & Sales	1823	304,966	0	304,966
SCEG	Marketing & Sales	1840	282	0	282
SCEG	Marketing & Sales	1860	0	9,830	9,830
SCEG	Marketing & Sales	4081	63,357	35,609	98,966
SCEG	Marketing & Sales	4082	54,381	2,105	56,486
SCEG	Marketing & Sales	4160	2,561,099	70,561	2,631,660
SCEG	Marketing & Sales	4171	198,457	7,917	206,374
SCEG	Marketing & Sales	4210	0	1,885	1,885
SCEG	Marketing & Sales	4261	10,084	0	10,084
SCEG	Marketing & Sales	4265	1,591,187	42,440	1,633,627
SCEG	Marketing & Sales	5560	212	0	212
SCEG	Marketing & Sales	5660	924	0	924
SCEG	Marketing & Sales	9050	0	(1,416)	(1,416)
SCEG	Marketing & Sales	9090	348	2,558	2,906
SCEG	Marketing & Sales	9110	2,814	0	2,814

SCEG	Marketing & Sales	9120	137,925	2,183	140,108
SCEG	Marketing & Sales	9130	0	(98)	(98)
SCEG	Marketing & Sales	9160	161,324	0	161,324
SCEG	Marketing & Sales	9200	352,606	498,465	851,071
SCEG	Marketing & Sales	9210	207,404	117,884	325,288
SCEG	Marketing & Sales	9230	0	14,592	14,592
SCEG	Marketing & Sales	9260	233,762	158,231	391,993
SCEG	Marketing & Sales	9280	801	0	801
SCEG	Marketing & Sales	9301	0	0	0
SCEG	Marketing & Sales	9302	83,352	34,606	117,958
SCEG	Marketing & Sales	9310	1,309	783	2,092
SCEG	Marketing & Sales	9350	0	77	77
SCEG	Procurement	1070	704,352	11,416	715,768
SCEG	Procurement	1080	40,799	0	40,799
SCEG	Procurement	1180	328,375	1,230	329,605
SCEG	Procurement	1630	348,986	0	348,986
SCEG	Procurement	1860	0	11,925	11,925
SCEG	Procurement	4081	32,349	64,415	96,764
SCEG	Procurement	4082	0	123	123
SCEG	Procurement	4171	0	470	470
SCEG	Procurement	4210	0	2,287	2,287
SCEG	Procurement	4265	1	23,120	23,121
SCEG	Procurement	5490	169	0	169
SCEG	Procurement	5880	0	0	0
SCEG	Procurement	8790	298	0	298
SCEG	Procurement	9130	0	47	47
SCEG	Procurement	9200	456,679	881,058	1,337,737
SCEG	Procurement	9210	8,513	128,540	137,053
SCEG	Procurement	9230	0	33,302	33,302
SCEG	Procurement	9260	115,459	262,889	378,348
SCEG	Procurement	9302	0	60,673	60,673
SCEG	Procurement	9310	5,506	0	5,506
SCEG	Public Affairs	1070	308,739	13,783	322,522
SCEG	Public Affairs	1180	12	1,502	1,514
SCEG	Public Affairs	1823	608	0	608
SCEG	Public Affairs	1860	0	11,904	11,904
SCEG	Public Affairs	4081	58,983	31,102	90,085
SCEG	Public Affairs	4082	50,056	30,258	80,314
SCEG	Public Affairs	4171	177,571	108,078	285,649
SCEG	Public Affairs	4210	0	2,283	2,283
SCEG	Public Affairs	4261	5,368,525	134,157	5,502,682
SCEG	Public Affairs	4262	0	59	59
SCEG	Public Affairs	4264	874,172	480,920	1,355,092
SCEG	Public Affairs	4265	1,370,679	477,952	1,848,631
SCEG	Public Affairs	9080	233	0	233

SCEG	Public Affairs	9120	0	28	28
SCEG	Public Affairs	9200	822,841	425,806	1,248,647
SCEG	Public Affairs	9210	1,039,437	487,069	1,526,506
SCEG	Public Affairs	9260	207,486	133,719	341,205
SCEG	Public Affairs	9280	973	0	973
SCEG	Public Affairs	9302	24,638	0	24,638
SCEG	Public Affairs	9310	2,162	12,307	14,469
SCEG	Public Affairs	9350	0	421	421
SCEG	Regulatory	1070	345,540	6,352	351,892
SCEG	Regulatory	1180	0	684	684
SCEG	Regulatory	1823	46,859	0	46,859
SCEG	Regulatory	1860	0	6,635	6,635
SCEG	Regulatory	4081	92,303	1,027	93,330
SCEG	Regulatory	4082	0	598	598
SCEG	Regulatory	4171	0	2,209	2,209
SCEG	Regulatory	4210	0	1,273	1,273
SCEG	Regulatory	4264	931	0	931
SCEG	Regulatory	4265	2,504	9,962	12,466
SCEG	Regulatory	9200	905,390	21,239	926,629
SCEG	Regulatory	9210	39,754	1,266	41,020
SCEG	Regulatory	9230	170	0	170
SCEG	Regulatory	9260	329,636	25,249	354,885
SCEG	Regulatory	9280	444,618	0	444,618
SCEG	Regulatory	9310	4,740	0	4,740
SCEG	Strategic Planning	1070	219,638	10,178	229,816
SCEG	Strategic Planning	1180	298	1,090	1,388
SCEG	Strategic Planning	1860	0	10,323	10,323
SCEG	Strategic Planning	4081	103,469	34,026	137,495
SCEG	Strategic Planning	4082	0	1,557	1,557
SCEG	Strategic Planning	4171	0	6,093	6,093
SCEG	Strategic Planning	4210	0	1,980	1,980
SCEG	Strategic Planning	4265	2,688	34,547	37,235
SCEG	Strategic Planning	9200	1,447,060	472,410	1,919,470
SCEG	Strategic Planning	9210	218,723	82,593	301,316
SCEG	Strategic Planning	9260	365,412	152,963	518,375
SCEG	Strategic Planning	9280	567	0	567
SCEG	Strategic Planning	9302	1,555,865	1,005	1,556,870
SCEG	Strategic Planning	9310	7,701	0	7,701
	Grand Total		226,775,301	68,140,403	294,915,704

Incentive compensation costs are included in the Employee Services category.

The Financial Services category includes depreciation, property taxes, accrued payroll and other costs recorded at a corporate level by SCANA Services, Inc.

Allocated costs billed from SCANA Services, Inc. are billed using one of the accepted methodologies described below.

1. Information Systems Charge-back Rates - Rates for services, including but not limited to Software, Consulting, Mainframe, Midtier and Network Connectivity Services, are based on the costs of labor, materials and Information Services overheads related to the provision of each service. Such rates are applied based on the specific equipment employed and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

2. Margin Revenue Ratio - "Margin" is equal to the excess of sales revenues over the applicable cost of sales, i.e., cost of fuel for generation and gas for resale. The numerator is equal to margin revenues for a specific Client Entity and the denominator is equal to the combined margin revenues of all the applicable Client Entities. This ratio is evaluated annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, based on results of operations for a subsequent twelve-month period, as may be required due to significant changes.

3. Number of Customers Ratio - A ratio based on the number of customers served by each subsidiary or operating unit. This ratio is determined annually based on actual number of customers and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

4. Number of Employees Ratio - A ratio based on the number of employees benefiting from the performance of a service. This ratio is determined annually based on actual counts of applicable employees and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

5. Three-Factor Formula - This formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

6. Modified Three-Factor Method - A ratio for the allocation of non-directly assigned corporate governance costs. The Modified Three-Factor Method provides for an allocation of costs to the principal holding company; the Three-Factor Method does not. The formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues. For the purpose of the Modified Three-Factor Method, the dividends resulting from operations of the subsidiaries are used as a proxy for revenues for the principal holding company.

7. Telecommunications Charge-back Rates - Rates for use of telecommunications services other than those encompassed by Information Systems Charge-back Rates are based on the costs of labor, materials, outside services and Telecommunications overheads. Such rates are applied based on the specific equipment employment and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

8. Gas Sales Ratio - A ratio based on the actual number of dekatherms of natural gas sold by the applicable gas distribution or marketing operations. This ratio is determined annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, as may be required due to significant changes.

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Amount based on measured usage of assets to include computer resource usage, margin revenues, three factor formula and number of employees.

Schedule	Page No.

Allocators:		**September, 2017**			1-8 Attachment
CODE	DESCRIPTION	ALLOCATES:	UPDATED:	% TOTAL	% RETAIL
E10	Energy Sales @ Generation Level	Interchange Delivered to Retail, Fuel Costs	Monthly		95.930%
P10	Allocated Production Plant	Production Plant to Retail, Prod. O&M	@ 8/17 Peak		96.830%
P20	Allocated Transmission Plant	Transmission Plant to Retail, Trans. O&M	@ 8/17 Peak		96.665%
P20L	Allocated Transmission Plant Excl. Land	"	@ 8/17 Peak		96.670%
P30	Allocated Distribution Plant	Distribution Plant to Retail, Dist. O&M	@ 8/17 Peak		99.989%
P30L	Allocated Distribution Plant Excl. Land	"	@ 8/17 Peak		99.989%
ECOM	Electric Common Plant Ratio	Common Plant	Annually (March)	90.24%	
POO	Allocated Plant in Service Sum	General, Intangible, Common Plt., M&S, & Prepay. to Retail	Automatically		97.920%
POOL	POO Less Land	General, Intangible, Common Plt., M&S, & Prepay. to Retail	Automatically		97.715%
LABOR		A & G Exp. To Retail, OPEB Rate Base	Per C.O.S. (2011)		97.300%
CCUSTA	Average Annual Electric Customers	Customer Expenses, Customer Growth	Monthly	802,543	
CCUSTYE	Year End Electric Customers	Customer Expenses, Customer Growth	Monthly	806,428	
CCUSTRE	Retail Average Electric Customers	Customer Expenses, Customer Growth	Monthly		802,540
NETPLT	Net Plant Ratios	TD2 (Interest Exp.)	Automatically		98.054%
SPECIAL	Refund Allocator	Allocates Refund Adjustments to Retail	Per C.O.S.		93.990%
TOTREV	Revenue Inside Munis.	Allocates Fed. Muni. Lic. Tax Deduction to Retail	Per C.O.S.		100.000%
PTD	Prod, Trans. & Dist. Allocator	Allocates Environmental to Retail	Per C.O.S. (2011)		97.198%
ECD	Electric Customer Deposits Factor	Allocates CDs and Interest on CDs to E&G	Annually (3/17)	0.8685178	
OTX	Other Taxes Allocator	Taxes Other Than Income to Retail	Automatically	16,015,127,402	
From Resource Planning Dept for **SEPTEMBER 2017**					
	Average Annual Custome	AVGCUST Column Totals		3	WHOLESALE
	Class 1	612,850		802,540	RETAIL
	Class 2	89,512		802,543	TOTAL
	Class 3	97,101			
	Class 4	2,709			
	Class 5	368			
	Class 7	3			
	Year End Customers	CUST Column Totals		3	WHOLESALE
	Class 1	616,186		806,425	RETAIL
	Class 2	89,583		806,428	TOTAL
	Class 3	97,577			
	Class 4	2,711			
	Class 5	368			
	Class 7	3			

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

Response No. 1-13

RATE	SEPT. 30, 2017 RATES REVENUE	PROPOSED REVENUE	$ CHANGE	% CHANGE
	COL. 1	COL. 2	COL. 3	COL. 4
RESIDENTIAL				
Rate 1 - Good Cents	$ 43,824,847	$ 42,309,308	$ (1,515,539)	
Rate 2 - Low Use	$ 4,477,937	$ 4,372,680	$ (105,257)	
Rate 5 - Time-of-Use (KWH Only)	$ 143,896	$ 139,108	$ (4,788)	
Rate 6 - Energy Saver / Conservation	$ 63,118,698	$ 60,938,753	$ (2,179,945)	
Rate 7 - Time-of-Use Demand	$ 33,401	$ 32,454	$ (947)	
Rate 8 - Residential	$ 1,002,758,129	$ 967,561,693	$ (35,196,436)	
Total Residential Class	**$ 1,114,356,908**	**$ 1,075,353,996**	**$ (39,002,912)**	**-3.5%**
SMALL GENERAL SERVICE				
Rate 3 - Municipal Power	$ 19,058,748	$ 18,405,378	$ (653,370)	
Rate 9 - Small General (Includes Unmetered Svc.)	$ 364,257,726	$ 351,416,343	$ (12,841,383)	
Rate 29 - Small General (Unmetered)	$ 655,952	$ 634,373	$ (21,579)	
Rate 10 - Small Construction	$ 1,001,421	$ 977,429	$ (23,992)	
Rate 11 - Irrigation	$ 1,322,201	$ 1,280,079	$ (42,122)	
Rate 12 - Church	$ 17,949,011	$ 17,316,567	$ (632,444)	
Rate 13 - Municipal Lighting	$ 509,874	$ 498,212	$ (11,662)	
Rate 14 - Farm	$ 3,083,605	$ 2,977,378	$ (106,227)	
Rate 16 - Time-of-Use	$ 6,039,449	$ 5,840,405	$ (199,044)	
Rate 22 - School	$ 50,361,281	$ 48,645,818	$ (1,715,463)	
Rate 28 - Time-of-Use Demand	$ 303,658	$ 291,845	$ (11,813)	
Total Small General Service Class	**$ 464,542,926**	**$ 448,283,827**	**$ (16,259,099)**	**-3.5%**
MEDIUM GENERAL SERVICE				
Rate 20 - Medium General	$ 202,832,317	$ 195,832,344	$ (6,999,973)	
Rate 21 - Time-of-Use	$ 13,040,192	$ 12,605,619	$ (434,573)	
Rate 21A - Experimental Time-of-Use	$ 22,123,391	$ 21,303,607	$ (819,784)	
Total Medium General Service Class	**$ 237,995,900**	**$ 229,741,570**	**$ (8,254,330)**	**-3.5%**
LARGE GENERAL SERVICE				
Rate 23 - Industrial Power	$ 273,856,448	$ 263,707,271	$ (10,149,177)	
Rate 24 - Time-of-Use	$ 171,271,135	$ 165,275,950	$ (5,995,185)	
Contracts	$ 161,041,131	$ 155,968,194	$ (5,072,937)	
Total Large General Service Class	**$ 606,168,714**	**$ 584,951,415**	**$ (21,217,299)**	**-3.5%**
RETAIL TOTAL EXCLUDING LIGHTING	**$ 2,423,064,448**	**$ 2,338,330,808**	**$ (84,733,640)**	**-3.5%**

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
1	Oct-16	200	67,123	668	67,123	668
1	Oct-16	400	469,345	1,497	536,468	2,165
1	Oct-16	800	3,514,938	5,728	4,051,406	7,893
1	Oct-16	1000	3,029,395	3,386	7,080,801	11,279
1	Oct-16	2000	11,789,120	8,609	18,869,921	19,888
1	Oct-16	3000	2,956,722	1,253	21,826,643	21,141
1	Oct-16	4000	691,319	206	22,517,962	21,347
1	Oct-16	5000	149,286	34	22,667,248	21,381
1	Oct-16	10000	60,406	11	22,727,654	21,392
1	Nov-16	200	97,601	1,041	97,601	1,041
1	Nov-16	400	688,354	2,243	785,955	3,284
1	Nov-16	800	4,598,937	7,580	5,384,892	10,864
1	Nov-16	1000	3,190,163	3,551	8,575,055	14,415
1	Nov-16	2000	8,333,132	6,273	16,908,187	20,688
1	Nov-16	3000	1,381,643	588	18,289,830	21,276
1	Nov-16	4000	262,787	78	18,552,617	21,354
1	Nov-16	5000	98,819	23	18,651,436	21,377
1	Nov-16	10000	36,215	6	18,687,651	21,383
1	Dec-16	200	77,925	743	77,925	743
1	Dec-16	400	420,236	1,386	498,161	2,129
1	Dec-16	800	2,918,745	4,754	3,416,906	6,883
1	Dec-16	1000	2,657,493	2,955	6,074,399	9,838
1	Dec-16	2000	13,207,297	9,458	19,281,696	19,296
1	Dec-16	3000	4,178,618	1,770	23,460,314	21,066
1	Dec-16	4000	923,086	270	24,383,400	21,336
1	Dec-16	5000	174,328	40	24,557,728	21,376
1	Dec-16	10000	162,535	28	24,720,263	21,404
1	Jan-17	200	58,598	566	58,598	566
1	Jan-17	400	319,628	1,042	378,226	1,608
1	Jan-17	800	2,200,116	3,584	2,578,342	5,192
1	Jan-17	1000	2,077,174	2,302	4,655,516	7,494
1	Jan-17	2000	14,448,187	9,996	19,103,703	17,490
1	Jan-17	3000	7,354,673	3,086	26,458,376	20,576
1	Jan-17	4000	2,090,261	618	28,548,637	21,194
1	Jan-17	5000	571,806	131	29,120,443	21,325
1	Jan-17	10000	317,047	52	29,437,490	21,377
1	Feb-17	200	87,367	830	87,367	830
1	Feb-17	400	517,116	1,657	604,483	2,487
1	Feb-17	800	3,627,908	5,911	4,232,391	8,398
1	Feb-17	1000	3,081,180	3,413	7,313,571	11,811
1	Feb-17	2000	11,440,363	8,424	18,753,934	20,235
1	Feb-17	3000	2,329,977	991	21,083,911	21,226
1	Feb-17	4000	412,238	121	21,496,149	21,347
1	Feb-17	5000	97,476	22	21,593,625	21,369
1	Feb-17	10000	50,101	9	21,643,726	21,378

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
1	Mar-17	200	82,094	803	82,094	803
1	Mar-17	400	499,886	1,608	581,980	2,411
1	Mar-17	800	3,645,142	5,960	4,227,122	8,371
1	Mar-17	1000	3,043,552	3,379	7,270,674	11,750
1	Mar-17	2000	11,529,904	8,503	18,800,578	20,253
1	Mar-17	3000	2,425,389	1,033	21,225,967	21,286
1	Mar-17	4000	392,286	117	21,618,253	21,403
1	Mar-17	5000	92,124	20	21,710,377	21,423
1	Mar-17	10000	64,310	11	21,774,687	21,434
1	Apr-17	200	96,077	960	96,077	960
1	Apr-17	400	638,035	2,074	734,112	3,034
1	Apr-17	800	4,204,245	6,928	4,938,357	9,962
1	Apr-17	1000	3,256,686	3,630	8,195,043	13,592
1	Apr-17	2000	9,396,803	7,024	17,591,846	20,616
1	Apr-17	3000	1,613,357	678	19,205,203	21,294
1	Apr-17	4000	276,092	76	19,481,295	21,370
1	Apr-17	5000	60,268	14	19,541,563	21,384
1	Apr-17	10000	33,169	6	19,574,732	21,390
1	May-17	200	77,828	845	77,828	845
1	May-17	400	453,613	1,447	531,441	2,292
1	May-17	800	3,145,201	5,121	3,676,642	7,413
1	May-17	1000	2,820,848	3,142	6,497,490	10,555
1	May-17	2000	12,433,843	9,000	18,931,333	19,555
1	May-17	3000	3,654,036	1,526	22,585,369	21,081
1	May-17	4000	900,725	258	23,486,094	21,339
1	May-17	5000	227,532	50	23,713,626	21,389
1	May-17	10000	152,173	26	23,865,799	21,415
1	Jun-17	200	53,735	634	53,735	634
1	Jun-17	400	266,517	861	320,252	1,495
1	Jun-17	800	2,094,589	3,392	2,414,841	4,887
1	Jun-17	1000	2,189,553	2,430	4,604,394	7,317
1	Jun-17	2000	14,937,435	10,371	19,541,829	17,688
1	Jun-17	3000	7,164,644	2,996	26,706,473	20,684
1	Jun-17	4000	2,117,692	619	28,824,165	21,303
1	Jun-17	5000	569,951	127	29,394,116	21,430
1	Jun-17	10000	332,275	54	29,726,391	21,484
1	Jul-17	200	40,465	508	40,465	508
1	Jul-17	400	216,795	705	257,260	1,213
1	Jul-17	800	1,744,202	2,820	2,001,462	4,033
1	Jul-17	1000	1,872,215	2,087	3,873,677	6,120
1	Jul-17	2000	15,545,336	10,613	19,419,013	16,733
1	Jul-17	3000	8,681,581	3,602	28,100,594	20,335
1	Jul-17	4000	2,924,503	855	31,025,097	21,190
1	Jul-17	5000	817,245	183	31,842,342	21,373
1	Jul-17	10000	463,483	74	32,305,825	21,447

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
1	Jul-17	25000	10,246	1	32,316,071	21,448
1	Aug-17	200	37,509	469	37,509	469
1	Aug-17	400	186,846	617	224,355	1,086
1	Aug-17	800	1,605,862	2,565	1,830,217	3,651
1	Aug-17	1000	1,679,026	1,876	3,509,243	5,527
1	Aug-17	2000	15,467,413	10,506	18,976,656	16,033
1	Aug-17	3000	9,944,128	4,138	28,920,784	20,171
1	Aug-17	4000	3,385,260	991	32,306,044	21,162
1	Aug-17	5000	1,129,085	253	33,435,129	21,415
1	Aug-17	10000	571,581	92	34,006,710	21,507
1	Aug-17	25000	10,128	1	34,016,838	21,508
1	Sep-17	200	42,836	486	42,836	486
1	Sep-17	400	249,045	813	291,881	1,299
1	Sep-17	800	2,154,025	3,451	2,445,906	4,750
1	Sep-17	1000	2,201,225	2,440	4,647,131	7,190
1	Sep-17	2000	15,192,640	10,620	19,839,771	17,810
1	Sep-17	3000	6,904,005	2,896	26,743,776	20,706
1	Sep-17	4000	1,869,506	547	28,613,282	21,253
1	Sep-17	5000	528,268	113	29,141,550	21,366
1	Sep-17	10000	238,628	39	29,380,178	21,405
2	Oct-16	200	831,098	12,440	831,098	12,440
2	Oct-16	400	610,888	2,343	1,441,986	14,783
2	Oct-16	800	117,561	219	1,559,547	15,002
2	Oct-16	1000	18,021	18	1,577,568	15,020
2	Oct-16	2000	30,233	23	1,607,801	15,043
2	Oct-16	3000	6,646	1	1,614,447	15,044
2	Nov-16	200	818,892	12,802	818,892	12,802
2	Nov-16	400	505,495	1,934	1,324,387	14,736
2	Nov-16	800	114,175	214	1,438,562	14,950
2	Nov-16	1000	17,158	17	1,455,720	14,967
2	Nov-16	2000	31,391	22	1,487,111	14,989
2	Nov-16	3000	6,788	3	1,493,899	14,992
2	Nov-16	4000	3,293	1	1,497,192	14,993
2	Dec-16	200	766,947	12,111	766,947	12,111
2	Dec-16	400	646,237	2,387	1,413,184	14,498
2	Dec-16	800	209,648	390	1,622,832	14,888
2	Dec-16	1000	37,091	44	1,659,923	14,932
2	Dec-16	2000	92,750	64	1,752,673	14,996
2	Dec-16	3000	21,538	7	1,774,211	15,003
2	Dec-16	4000	6,498	2	1,780,709	15,005
2	Jan-17	200	717,786	11,363	717,786	11,363
2	Jan-17	400	761,626	2,768	1,479,412	14,131
2	Jan-17	800	311,280	587	1,790,692	14,718
2	Jan-17	1000	48,581	54	1,839,273	14,772
2	Jan-17	2000	110,950	80	1,950,223	14,852

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
2	Jan-17	3000	25,645	11	1,975,868	14,863
2	Jan-17	4000	7,360	2	1,983,228	14,865
2	Feb-17	200	771,523	12,364	771,523	12,364
2	Feb-17	400	587,270	2,205	1,358,793	14,569
2	Feb-17	800	115,974	212	1,474,767	14,781
2	Feb-17	1000	15,200	17	1,489,967	14,798
2	Feb-17	2000	51,879	37	1,541,846	14,835
2	Feb-17	3000	6,781	3	1,548,627	14,838
2	Feb-17	4000	3,119	1	1,551,746	14,839
2	Mar-17	200	812,644	12,469	812,644	12,469
2	Mar-17	400	701,972	2,633	1,514,616	15,102
2	Mar-17	800	139,140	254	1,653,756	15,356
2	Mar-17	1000	14,276	13	1,668,032	15,369
2	Mar-17	2000	38,676	30	1,706,708	15,399
2	Mar-17	3000	17,027	7	1,723,735	15,406
2	Mar-17	5000	4,037	1	1,727,772	15,407
2	Apr-17	200	883,309	13,199	883,309	13,199
2	Apr-17	400	594,229	2,276	1,477,538	15,475
2	Apr-17	800	95,130	170	1,572,668	15,645
2	Apr-17	1000	21,177	23	1,593,845	15,668
2	Apr-17	2000	16,918	14	1,610,763	15,682
2	Apr-17	3000	7,010	2	1,617,773	15,684
2	May-17	200	852,107	12,391	852,107	12,391
2	May-17	400	782,123	2,937	1,634,230	15,328
2	May-17	800	158,705	295	1,792,935	15,623
2	May-17	1000	25,210	27	1,818,145	15,650
2	May-17	2000	51,410	33	1,869,555	15,683
2	May-17	3000	2,133	1	1,871,688	15,684
2	May-17	10000	5,312	1	1,877,000	15,685
2	Jun-17	200	754,685	11,260	754,685	11,260
2	Jun-17	400	996,857	3,622	1,751,542	14,882
2	Jun-17	800	333,208	611	2,084,750	15,493
2	Jun-17	1000	52,765	56	2,137,515	15,549
2	Jun-17	2000	79,592	60	2,217,107	15,609
2	Jun-17	3000	4,775	2	2,221,882	15,611
2	Jun-17	4000	3,333	1	2,225,215	15,612
2	Jul-17	200	702,163	10,847	702,163	10,847
2	Jul-17	400	1,029,767	3,647	1,731,930	14,494
2	Jul-17	800	451,591	841	2,183,521	15,335
2	Jul-17	1000	86,465	94	2,269,986	15,429
2	Jul-17	2000	111,528	79	2,381,514	15,508
2	Jul-17	3000	21,071	9	2,402,585	15,517
2	Jul-17	4000	7,047	1	2,409,632	15,518
2	Aug-17	200	674,032	10,512	674,032	10,512
2	Aug-17	400	1,117,853	3,924	1,791,885	14,436

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
2	Aug-17	800	484,536	930	2,276,421	15,366
2	Aug-17	1000	66,056	70	2,342,477	15,436
2	Aug-17	2000	116,947	82	2,459,424	15,518
2	Aug-17	3000	20,396	9	2,479,820	15,527
2	Aug-17	4000	6,584	2	2,486,404	15,529
2	Sep-17	200	774,964	11,482	774,964	11,482
2	Sep-17	400	1,153,584	4,177	1,928,548	15,659
2	Sep-17	800	302,189	563	2,230,737	16,222
2	Sep-17	1000	48,667	54	2,279,404	16,276
2	Sep-17	2000	74,203	58	2,353,607	16,334
2	Sep-17	3000	8,603	2	2,362,210	16,336
3	Oct-16	200	80,431	1,377	80,431	1,377
3	Oct-16	400	103,425	364	183,856	1,741
3	Oct-16	800	213,411	372	397,267	2,113
3	Oct-16	1000	109,755	124	507,022	2,237
3	Oct-16	2000	535,632	369	1,042,654	2,606
3	Oct-16	3000	407,560	170	1,450,214	2,776
3	Oct-16	4000	296,881	85	1,747,095	2,861
3	Oct-16	5000	331,838	74	2,078,933	2,935
3	Oct-16	10000	1,450,315	201	3,529,248	3,136
3	Oct-16	25000	2,215,162	147	5,744,410	3,283
3	Oct-16	50000	1,954,400	57	7,698,810	3,340
3	Oct-16	100000	2,479,740	34	10,178,550	3,374
3	Oct-16	250000	1,591,720	12	11,770,270	3,386
3	Oct-16	500000	698,600	2	12,468,870	3,388
3	Oct-16	Over 500k	502,800	1	12,971,670	3,389
3	Nov-16	200	70,470	1,399	70,470	1,399
3	Nov-16	400	106,567	377	177,037	1,776
3	Nov-16	800	227,400	396	404,437	2,172
3	Nov-16	1000	116,185	132	520,622	2,304
3	Nov-16	2000	500,093	358	1,020,715	2,662
3	Nov-16	3000	405,216	165	1,425,931	2,827
3	Nov-16	4000	279,797	81	1,705,728	2,908
3	Nov-16	5000	317,871	71	2,023,599	2,979
3	Nov-16	10000	1,352,726	189	3,376,325	3,168
3	Nov-16	25000	1,968,327	127	5,344,652	3,295
3	Nov-16	50000	1,608,921	47	6,953,573	3,342
3	Nov-16	100000	2,475,660	35	9,429,233	3,377
3	Nov-16	250000	1,387,120	10	10,816,353	3,387
3	Nov-16	500000	418,650	1	11,235,003	3,388
3	Nov-16	Over 500k	515,600	1	11,750,603	3,389
3	Dec-16	200	78,132	1,339	78,132	1,339
3	Dec-16	400	105,779	365	183,911	1,704
3	Dec-16	800	226,706	396	410,617	2,100
3	Dec-16	1000	115,200	131	525,817	2,231

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
3	Dec-16	2000	529,681	370	1,055,498	2,601
3	Dec-16	3000	421,983	172	1,477,481	2,773
3	Dec-16	4000	386,576	112	1,864,057	2,885
3	Dec-16	5000	330,958	74	2,195,015	2,959
3	Dec-16	10000	1,297,654	184	3,492,669	3,143
3	Dec-16	25000	2,188,640	145	5,681,309	3,288
3	Dec-16	50000	1,762,920	51	7,444,229	3,339
3	Dec-16	100000	2,550,200	36	9,994,429	3,375
3	Dec-16	250000	1,354,400	9	11,348,829	3,384
3	Dec-16	500000	858,200	2	12,207,029	3,386
3	Jan-17	200	74,234	1,272	74,234	1,272
3	Jan-17	400	105,743	367	179,977	1,639
3	Jan-17	800	201,983	353	381,960	1,992
3	Jan-17	1000	126,307	142	508,267	2,134
3	Jan-17	2000	506,570	360	1,014,837	2,494
3	Jan-17	3000	525,376	215	1,540,213	2,709
3	Jan-17	4000	429,303	124	1,969,516	2,833
3	Jan-17	5000	340,249	77	2,309,765	2,910
3	Jan-17	10000	1,453,861	205	3,763,626	3,115
3	Jan-17	25000	2,459,716	164	6,223,342	3,279
3	Jan-17	50000	2,053,010	59	8,276,352	3,338
3	Jan-17	100000	2,376,080	35	10,652,432	3,373
3	Jan-17	250000	1,785,420	12	12,437,852	3,385
3	Jan-17	500000	433,350	1	12,871,202	3,386
3	Jan-17	Over 500k	555,600	1	13,426,802	3,387
3	Feb-17	200	77,059	1,388	77,059	1,388
3	Feb-17	400	98,255	347	175,314	1,735
3	Feb-17	800	228,675	396	403,989	2,131
3	Feb-17	1000	115,204	129	519,193	2,260
3	Feb-17	2000	527,662	368	1,046,855	2,628
3	Feb-17	3000	414,117	169	1,460,972	2,797
3	Feb-17	4000	353,023	104	1,813,995	2,901
3	Feb-17	5000	335,162	75	2,149,157	2,976
3	Feb-17	10000	1,442,812	202	3,591,969	3,178
3	Feb-17	25000	1,941,238	129	5,533,207	3,307
3	Feb-17	50000	1,951,760	57	7,484,967	3,364
3	Feb-17	100000	2,018,860	30	9,503,827	3,394
3	Feb-17	250000	1,331,480	10	10,835,307	3,404
3	Feb-17	500000	816,800	2	11,652,107	3,406
3	Mar-17	200	76,949	1,359	76,949	1,359
3	Mar-17	400	105,284	372	182,233	1,731
3	Mar-17	800	231,050	404	413,283	2,135
3	Mar-17	1000	121,072	135	534,355	2,270
3	Mar-17	2000	512,996	362	1,047,351	2,632
3	Mar-17	3000	417,166	172	1,464,517	2,804

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
3	Mar-17	4000	343,918	100	1,808,435	2,904
3	Mar-17	5000	318,556	71	2,126,991	2,975
3	Mar-17	10000	1,427,371	200	3,554,362	3,175
3	Mar-17	25000	2,147,632	139	5,701,994	3,314
3	Mar-17	50000	1,769,530	51	7,471,524	3,365
3	Mar-17	100000	2,196,360	32	9,667,884	3,397
3	Mar-17	250000	1,578,040	11	11,245,924	3,408
3	Mar-17	500000	428,850	1	11,674,774	3,409
3	Mar-17	Over 500k	601,600	1	12,276,374	3,410
3	Apr-17	200	83,732	1,402	83,732	1,402
3	Apr-17	400	109,463	382	193,195	1,784
3	Apr-17	800	233,906	400	427,101	2,184
3	Apr-17	1000	121,059	136	548,160	2,320
3	Apr-17	2000	508,458	354	1,056,618	2,674
3	Apr-17	3000	384,911	158	1,441,529	2,832
3	Apr-17	4000	313,137	91	1,754,666	2,923
3	Apr-17	5000	379,875	85	2,134,541	3,008
3	Apr-17	10000	1,241,286	175	3,375,827	3,183
3	Apr-17	25000	2,006,443	131	5,382,270	3,314
3	Apr-17	50000	1,802,840	51	7,185,110	3,365
3	Apr-17	100000	1,578,120	24	8,763,230	3,389
3	Apr-17	250000	2,038,900	15	10,802,130	3,404
3	Apr-17	500000	436,050	1	11,238,180	3,405
3	Apr-17	Over 500k	740,000	1	11,978,180	3,406
3	May-17	200	79,471	1,381	79,471	1,381
3	May-17	400	111,477	390	190,948	1,771
3	May-17	800	210,995	366	401,943	2,137
3	May-17	1000	117,105	133	519,048	2,270
3	May-17	2000	527,877	367	1,046,925	2,637
3	May-17	3000	452,609	187	1,499,534	2,824
3	May-17	4000	298,138	86	1,797,672	2,910
3	May-17	5000	327,162	71	2,124,834	2,981
3	May-17	10000	1,476,247	206	3,601,081	3,187
3	May-17	25000	2,217,439	142	5,818,520	3,329
3	May-17	50000	1,926,065	56	7,744,585	3,385
3	May-17	100000	2,248,180	32	9,992,765	3,417
3	May-17	250000	2,546,560	18	12,539,325	3,435
3	May-17	500000	746,320	2	13,285,645	3,437
3	May-17	Over 500k	759,200	1	14,044,845	3,438
3	Jun-17	200	77,052	1,366	77,052	1,366
3	Jun-17	400	105,470	376	182,522	1,742
3	Jun-17	800	213,220	371	395,742	2,113
3	Jun-17	1000	107,559	120	503,301	2,233
3	Jun-17	2000	524,940	363	1,028,241	2,596
3	Jun-17	3000	462,116	190	1,490,357	2,786

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
3	Jun-17	4000	372,516	109	1,862,873	2,895
3	Jun-17	5000	298,957	66	2,161,830	2,961
3	Jun-17	10000	1,408,663	199	3,570,493	3,160
3	Jun-17	25000	2,692,441	178	6,262,934	3,338
3	Jun-17	50000	2,031,578	59	8,294,512	3,397
3	Jun-17	100000	1,969,170	29	10,263,682	3,426
3	Jun-17	250000	3,416,840	24	13,680,522	3,450
3	Jun-17	500000	260,960	1	13,941,482	3,451
3	Jun-17	Over 500k	1,220,200	2	15,161,682	3,453
3	Jul-17	200	81,461	1,431	81,461	1,431
3	Jul-17	400	102,405	363	183,866	1,794
3	Jul-17	800	202,092	353	385,958	2,147
3	Jul-17	1000	89,206	99	475,164	2,246
3	Jul-17	2000	531,441	368	1,006,605	2,614
3	Jul-17	3000	464,927	191	1,471,532	2,805
3	Jul-17	4000	352,484	102	1,824,016	2,907
3	Jul-17	5000	329,674	73	2,153,690	2,980
3	Jul-17	10000	1,401,127	195	3,554,817	3,175
3	Jul-17	25000	2,567,992	171	6,122,809	3,346
3	Jul-17	50000	2,106,514	61	8,229,323	3,407
3	Jul-17	100000	2,289,810	33	10,519,133	3,440
3	Jul-17	250000	2,789,080	19	13,308,213	3,459
3	Jul-17	500000	906,300	2	14,214,513	3,461
3	Aug-17	200	77,162	1,389	77,162	1,389
3	Aug-17	400	103,060	360	180,222	1,749
3	Aug-17	800	195,753	345	375,975	2,094
3	Aug-17	1000	112,194	126	488,169	2,220
3	Aug-17	2000	515,424	353	1,003,593	2,573
3	Aug-17	3000	452,591	185	1,456,184	2,758
3	Aug-17	4000	417,953	122	1,874,137	2,880
3	Aug-17	5000	373,961	84	2,248,098	2,964
3	Aug-17	10000	1,419,412	198	3,667,510	3,162
3	Aug-17	25000	2,756,892	185	6,424,402	3,347
3	Aug-17	50000	2,435,040	69	8,859,442	3,416
3	Aug-17	100000	2,428,560	35	11,288,002	3,451
3	Aug-17	250000	2,716,460	19	14,004,462	3,470
3	Aug-17	500000	1,448,880	4	15,453,342	3,474
3	Sep-17	200	78,633	1,396	78,633	1,396
3	Sep-17	400	95,779	342	174,412	1,738
3	Sep-17	800	221,341	383	395,753	2,121
3	Sep-17	1000	104,347	117	500,100	2,238
3	Sep-17	2000	512,917	350	1,013,017	2,588
3	Sep-17	3000	500,689	209	1,513,706	2,797
3	Sep-17	4000	396,113	113	1,909,819	2,910
3	Sep-17	5000	309,166	70	2,218,985	2,980

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
3	Sep-17	10000	1,446,560	206	3,665,545	3,186
3	Sep-17	25000	2,597,049	169	6,262,594	3,355
3	Sep-17	50000	2,058,995	59	8,321,589	3,414
3	Sep-17	100000	2,542,290	37	10,863,879	3,451
3	Sep-17	250000	2,624,860	19	13,488,739	3,470
3	Sep-17	500000	1,122,210	3	14,610,949	3,473
5	Oct-16	200	145	2	145	2
5	Oct-16	400	2,043	6	2,188	8
5	Oct-16	800	10,288	16	12,476	24
5	Oct-16	1000	10,879	12	23,355	36
5	Oct-16	2000	37,518	28	60,873	64
5	Oct-16	3000	8,888	4	69,761	68
5	Nov-16	200	515	5	515	5
5	Nov-16	400	2,960	9	3,475	14
5	Nov-16	800	14,660	25	18,135	39
5	Nov-16	1000	6,332	7	24,467	46
5	Nov-16	2000	29,677	21	54,144	67
5	Nov-16	3000	2,318	1	56,462	68
5	Dec-16	200	250	2	250	2
5	Dec-16	400	1,518	5	1,768	7
5	Dec-16	800	13,206	22	14,974	29
5	Dec-16	1000	6,200	8	21,174	37
5	Dec-16	2000	36,702	25	57,876	62
5	Dec-16	3000	22,965	10	80,841	72
5	Jan-17	200	252	2	252	2
5	Jan-17	400	509	2	761	4
5	Jan-17	800	9,857	16	10,618	20
5	Jan-17	1000	6,579	7	17,197	27
5	Jan-17	2000	47,729	33	64,926	60
5	Jan-17	3000	21,736	9	86,662	69
5	Jan-17	4000	3,746	1	90,408	70
5	Jan-17	5000	4,200	1	94,608	71
5	Feb-17	200	274	2	274	2
5	Feb-17	400	1,955	6	2,229	8
5	Feb-17	800	15,723	26	17,952	34
5	Feb-17	1000	7,296	8	25,248	42
5	Feb-17	2000	35,425	26	60,673	68
5	Feb-17	3000	7,880	3	68,553	71
5	Mar-17	200	260	2	260	2
5	Mar-17	400	2,012	6	2,272	8
5	Mar-17	800	14,884	25	17,156	33
5	Mar-17	1000	7,106	8	24,262	41
5	Mar-17	2000	33,345	26	57,607	67
5	Mar-17	3000	9,616	4	67,223	71
5	Apr-17	200	149	3	149	3

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
5	Apr-17	400	1,686	6	1,835	9
5	Apr-17	800	17,511	31	19,346	40
5	Apr-17	1000	7,922	9	27,268	49
5	Apr-17	2000	27,409	21	54,677	70
5	Apr-17	3000	2,269	1	56,946	71
5	May-17	200	460	4	460	4
5	May-17	400	849	3	1,309	7
5	May-17	800	13,582	21	14,891	28
5	May-17	1000	7,895	9	22,786	37
5	May-17	2000	40,396	30	63,182	67
5	May-17	3000	9,119	4	72,301	71
5	Jun-17	200	145	1	145	1
5	Jun-17	400	1,750	5	1,895	6
5	Jun-17	800	5,629	8	7,524	14
5	Jun-17	1000	7,945	9	15,469	23
5	Jun-17	2000	59,470	39	74,939	62
5	Jun-17	3000	17,346	7	92,285	69
5	Jun-17	4000	6,401	2	98,686	71
5	Jul-17	200	196	1	196	1
5	Jul-17	800	4,576	8	4,772	9
5	Jul-17	1000	7,999	9	12,771	18
5	Jul-17	2000	57,914	37	70,685	55
5	Jul-17	3000	32,339	14	103,024	69
5	Jul-17	4000	9,812	3	112,836	72
5	Aug-17	200	103	1	103	1
5	Aug-17	400	240	1	343	2
5	Aug-17	800	2,941	5	3,284	7
5	Aug-17	1000	8,019	9	11,303	16
5	Aug-17	2000	54,140	35	65,443	51
5	Aug-17	3000	36,208	16	101,651	67
5	Aug-17	4000	13,523	4	115,174	71
5	Sep-17	200	156	1	156	1
5	Sep-17	400	276	1	432	2
5	Sep-17	800	6,325	10	6,757	12
5	Sep-17	1000	9,000	10	15,757	22
5	Sep-17	2000	59,172	39	74,929	61
5	Sep-17	3000	19,283	8	94,212	69
5	Sep-17	4000	3,381	1	97,593	70
6	Oct-16	200	113,981	1,062	113,981	1,062
6	Oct-16	400	753,880	2,409	867,861	3,471
6	Oct-16	800	5,577,784	9,121	6,445,645	12,592
6	Oct-16	1000	4,509,988	5,015	10,955,633	17,607
6	Oct-16	2000	15,863,940	11,714	26,819,573	29,321
6	Oct-16	3000	3,861,491	1,633	30,681,064	30,954
6	Oct-16	4000	983,401	287	31,664,465	31,241

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
6	Oct-16	5000	258,378	59	31,922,843	31,300
6	Oct-16	10000	254,317	41	32,177,160	31,341
6	Oct-16	25000	11,243	1	32,188,403	31,342
6	Nov-16	200	162,936	1,565	162,936	1,565
6	Nov-16	400	1,133,784	3,650	1,296,720	5,215
6	Nov-16	800	6,914,771	11,505	8,211,491	16,720
6	Nov-16	1000	4,523,245	5,055	12,734,736	21,775
6	Nov-16	2000	11,402,417	8,644	24,137,153	30,419
6	Nov-16	3000	1,865,706	789	26,002,859	31,208
6	Nov-16	4000	442,887	128	26,445,746	31,336
6	Nov-16	5000	121,842	27	26,567,588	31,363
6	Nov-16	10000	141,525	23	26,709,113	31,386
6	Dec-16	200	134,464	1,220	134,464	1,220
6	Dec-16	400	737,868	2,369	872,332	3,589
6	Dec-16	800	4,589,320	7,595	5,461,652	11,184
6	Dec-16	1000	3,751,233	4,171	9,212,885	15,355
6	Dec-16	2000	18,502,371	13,218	27,715,256	28,573
6	Dec-16	3000	5,492,748	2,327	33,208,004	30,900
6	Dec-16	4000	1,244,594	369	34,452,598	31,269
6	Dec-16	5000	382,387	88	34,834,985	31,357
6	Dec-16	10000	256,631	42	35,091,616	31,399
6	Dec-16	25000	11,172	1	35,102,788	31,400
6	Jan-17	200	106,601	987	106,601	987
6	Jan-17	400	544,917	1,767	651,518	2,754
6	Jan-17	800	3,629,342	5,959	4,280,860	8,713
6	Jan-17	1000	3,065,523	3,408	7,346,383	12,121
6	Jan-17	2000	19,926,039	13,824	27,272,422	25,945
6	Jan-17	3000	10,199,443	4,273	37,471,865	30,218
6	Jan-17	4000	2,849,072	844	40,320,937	31,062
6	Jan-17	5000	949,834	214	41,270,771	31,276
6	Jan-17	10000	606,219	99	41,876,990	31,375
6	Jan-17	25000	32,741	3	41,909,731	31,378
6	Feb-17	200	146,932	1,367	146,932	1,367
6	Feb-17	400	884,893	2,850	1,031,825	4,217
6	Feb-17	800	5,600,482	9,265	6,632,307	13,482
6	Feb-17	1000	4,307,516	4,786	10,939,823	18,268
6	Feb-17	2000	15,574,220	11,541	26,514,043	29,809
6	Feb-17	3000	3,202,022	1,354	29,716,065	31,163
6	Feb-17	4000	599,430	176	30,315,495	31,339
6	Feb-17	5000	195,192	43	30,510,687	31,382
6	Feb-17	10000	146,602	23	30,657,289	31,405
6	Feb-17	25000	10,527	1	30,667,816	31,406
6	Mar-17	200	128,558	1,338	128,558	1,338
6	Mar-17	400	854,623	2,752	983,181	4,090
6	Mar-17	800	5,509,198	9,126	6,492,379	13,216

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
6	Mar-17	1000	4,327,400	4,811	10,819,779	18,027
6	Mar-17	2000	16,044,976	11,828	26,864,755	29,855
6	Mar-17	3000	3,271,146	1,392	30,135,901	31,247
6	Mar-17	4000	623,934	183	30,759,835	31,430
6	Mar-17	5000	186,180	42	30,946,015	31,472
6	Mar-17	10000	166,021	27	31,112,036	31,499
6	Mar-17	25000	10,400	1	31,122,436	31,500
6	Apr-17	200	155,840	1,570	155,840	1,570
6	Apr-17	400	1,026,752	3,269	1,182,592	4,839
6	Apr-17	800	6,609,318	10,941	7,791,910	15,780
6	Apr-17	1000	4,511,030	5,029	12,302,940	20,809
6	Apr-17	2000	12,598,451	9,481	24,901,391	30,290
6	Apr-17	3000	2,263,146	956	27,164,537	31,246
6	Apr-17	4000	511,816	148	27,676,353	31,394
6	Apr-17	5000	133,297	29	27,809,650	31,423
6	Apr-17	10000	121,082	19	27,930,732	31,442
6	May-17	200	108,979	1,236	108,979	1,236
6	May-17	400	678,871	2,186	787,850	3,422
6	May-17	800	4,965,729	8,115	5,753,579	11,537
6	May-17	1000	4,239,365	4,731	9,992,944	16,268
6	May-17	2000	17,465,788	12,662	27,458,732	28,930
6	May-17	3000	4,945,898	2,094	32,404,630	31,024
6	May-17	4000	1,196,018	350	33,600,648	31,374
6	May-17	5000	368,744	83	33,969,392	31,457
6	May-17	10000	330,661	53	34,300,053	31,510
6	May-17	25000	21,574	2	34,321,627	31,512
6	Jun-17	200	76,581	933	76,581	933
6	Jun-17	400	399,742	1,299	476,323	2,232
6	Jun-17	800	3,138,773	5,046	3,615,096	7,278
6	Jun-17	1000	3,271,680	3,636	6,886,776	10,914
6	Jun-17	2000	21,944,411	15,295	28,831,187	26,209
6	Jun-17	3000	9,913,664	4,149	38,744,851	30,358
6	Jun-17	4000	3,027,488	884	41,772,339	31,242
6	Jun-17	5000	936,886	210	42,709,225	31,452
6	Jun-17	10000	662,575	105	43,371,800	31,557
6	Jun-17	25000	32,511	3	43,404,311	31,560
6	Jul-17	200	65,297	827	65,297	827
6	Jul-17	400	292,294	975	357,591	1,802
6	Jul-17	800	2,522,102	4,099	2,879,693	5,901
6	Jul-17	1000	2,759,819	3,061	5,639,512	8,962
6	Jul-17	2000	22,930,548	15,697	28,570,060	24,659
6	Jul-17	3000	12,537,131	5,231	41,107,191	29,890
6	Jul-17	4000	3,864,446	1,132	44,971,637	31,022
6	Jul-17	5000	1,392,755	310	46,364,392	31,332
6	Jul-17	10000	863,969	137	47,228,361	31,469

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
6	Jul-17	25000	43,295	3	47,271,656	31,472
6	Aug-17	200	63,834	797	63,834	797
6	Aug-17	400	262,815	867	326,649	1,664
6	Aug-17	800	2,288,415	3,679	2,615,064	5,343
6	Aug-17	1000	2,592,211	2,878	5,207,275	8,221
6	Aug-17	2000	22,896,714	15,594	28,103,989	23,815
6	Aug-17	3000	14,009,627	5,843	42,113,616	29,658
6	Aug-17	4000	4,499,374	1,317	46,612,990	30,975
6	Aug-17	5000	1,746,309	392	48,359,299	31,367
6	Aug-17	10000	1,140,324	180	49,499,623	31,547
6	Aug-17	25000	46,695	3	49,546,318	31,550
6	Sep-17	200	72,773	810	72,773	810
6	Sep-17	400	382,385	1,231	455,158	2,041
6	Sep-17	800	3,243,987	5,214	3,699,145	7,255
6	Sep-17	1000	3,403,633	3,780	7,102,778	11,035
6	Sep-17	2000	22,141,476	15,534	29,244,254	26,569
6	Sep-17	3000	9,180,457	3,869	38,424,711	30,438
6	Sep-17	4000	2,616,451	770	41,041,162	31,208
6	Sep-17	5000	765,294	173	41,806,456	31,381
6	Sep-17	10000	672,253	108	42,478,709	31,489
6	Sep-17	25000	12,270	1	42,490,979	31,490
7	Oct-16	200	160	1	160	1
7	Oct-16	400	378	1	538	2
7	Oct-16	1000	927	1	1,465	3
7	Oct-16	2000	3,372	2	4,837	5
7	Oct-16	3000	2,498	1	7,335	6
7	Oct-16	4000	6,527	2	13,862	8
7	Oct-16	10000	6,979	1	20,841	9
7	Nov-16	200	167	1	167	1
7	Nov-16	800	765	1	932	2
7	Nov-16	1000	1,650	2	2,582	4
7	Nov-16	2000	2,978	2	5,560	6
7	Nov-16	3000	4,993	2	10,553	8
7	Nov-16	5000	4,962	1	15,515	9
7	Dec-16	200	113	1	113	1
7	Dec-16	1000	973	1	1,086	2
7	Dec-16	2000	4,099	3	5,185	5
7	Dec-16	3000	4,140	2	9,325	7
7	Dec-16	4000	3,070	1	12,395	8
7	Dec-16	5000	4,020	1	16,415	9
7	Dec-16	10000	5,502	1	21,917	10
7	Jan-17	400	277	1	277	1
7	Jan-17	1000	1,853	2	2,130	3
7	Jan-17	2000	1,815	1	3,945	4
7	Jan-17	3000	7,728	3	11,673	7

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
7	Jan-17	5000	8,760	2	20,433	9
7	Jan-17	10000	7,740	1	28,173	10
7	Feb-17	400	278	1	278	1
7	Feb-17	800	1,387	2	1,665	3
7	Feb-17	2000	6,872	4	8,537	7
7	Feb-17	3000	2,460	1	10,997	8
7	Feb-17	4000	3,480	1	14,477	9
7	Feb-17	10000	5,340	1	19,817	10
7	Mar-17	400	268	1	268	1
7	Mar-17	800	738	1	1,006	2
7	Mar-17	1000	900	1	1,906	3
7	Mar-17	2000	4,179	3	6,085	6
7	Mar-17	3000	4,440	2	10,525	8
7	Mar-17	5000	4,020	1	14,545	9
7	Mar-17	10000	5,100	1	19,645	10
7	Apr-17	200	143	1	143	1
7	Apr-17	400	349	1	492	2
7	Apr-17	1000	840	1	1,332	3
7	Apr-17	2000	3,841	3	5,173	6
7	Apr-17	3000	7,440	3	12,613	9
7	Apr-17	5000	4,980	1	17,593	10
7	May-17	200	183	1	183	1
7	May-17	800	534	1	717	2
7	May-17	1000	885	1	1,602	3
7	May-17	2000	2,580	2	4,182	5
7	May-17	3000	4,599	2	8,781	7
7	May-17	4000	6,600	2	15,381	9
7	May-17	10000	5,820	1	21,201	10
7	Jun-17	400	337	1	337	1
7	Jun-17	800	737	1	1,074	2
7	Jun-17	2000	4,808	3	5,882	5
7	Jun-17	3000	7,217	3	13,099	8
7	Jun-17	4000	3,060	1	16,159	9
7	Jun-17	10000	7,020	1	23,179	10
7	Jul-17	200	49	1	49	1
7	Jul-17	400	238	1	287	2
7	Jul-17	800	610	1	897	3
7	Jul-17	2000	4,919	3	5,816	6
7	Jul-17	3000	8,142	3	13,958	9
7	Jul-17	4000	3,120	1	17,078	10
7	Jul-17	10000	8,100	1	25,178	11
7	Aug-17	200	2	1	2	1
7	Aug-17	800	537	1	539	2
7	Aug-17	1000	858	1	1,397	3
7	Aug-17	2000	1,583	1	2,980	4

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
7	Aug-17	3000	9,943	4	12,923	8
7	Aug-17	4000	6,480	2	19,403	10
7	Aug-17	10000	7,800	1	27,203	11
7	Sep-17	800	1,715	3	1,715	3
7	Sep-17	2000	5,109	3	6,824	6
7	Sep-17	3000	4,480	2	11,304	8
7	Sep-17	4000	6,480	2	17,784	10
7	Sep-17	10000	7,560	1	25,344	11
8	Oct-16	200	2,582,107	26,765	2,582,107	26,765
8	Oct-16	400	16,841,532	53,998	19,423,639	80,763
8	Oct-16	800	108,650,048	179,579	128,073,687	260,342
8	Oct-16	1000	75,045,736	83,714	203,119,423	344,056
8	Oct-16	2000	232,282,748	172,714	435,402,171	516,770
8	Oct-16	3000	44,274,770	18,724	479,676,941	535,494
8	Oct-16	4000	9,161,132	2,671	488,838,073	538,165
8	Oct-16	5000	2,747,596	604	491,585,669	538,769
8	Oct-16	10000	2,304,979	367	493,890,648	539,136
8	Oct-16	25000	293,720	21	494,184,368	539,157
8	Oct-16	50000	54,171	2	494,238,539	539,159
8	Nov-16	200	3,946,624	40,996	3,946,624	40,996
8	Nov-16	400	26,301,778	85,537	30,248,402	126,533
8	Nov-16	800	126,602,868	214,207	156,851,270	340,740
8	Nov-16	1000	66,649,513	74,605	223,500,783	415,345
8	Nov-16	2000	150,768,508	114,272	374,269,291	529,617
8	Nov-16	3000	21,759,363	9,097	396,028,654	538,714
8	Nov-16	4000	4,735,465	1,365	400,764,119	540,079
8	Nov-16	5000	1,723,346	376	402,487,465	540,455
8	Nov-16	10000	1,482,111	231	403,969,576	540,686
8	Nov-16	25000	265,510	18	404,235,086	540,704
8	Nov-16	50000	48,212	2	404,283,298	540,706
8	Dec-16	200	3,220,231	32,613	3,220,231	32,613
8	Dec-16	400	18,521,192	59,676	21,741,423	92,289
8	Dec-16	800	99,285,605	166,286	121,027,028	258,575
8	Dec-16	1000	61,906,406	68,971	182,933,434	327,546
8	Dec-16	2000	243,388,304	175,096	426,321,738	502,642
8	Dec-16	3000	77,425,838	32,502	503,747,576	535,144
8	Dec-16	4000	17,417,717	5,055	521,165,293	540,199
8	Dec-16	5000	4,832,639	1,052	525,997,932	541,251
8	Dec-16	10000	3,135,523	497	529,133,455	541,748
8	Dec-16	25000	288,104	23	529,421,559	541,771
8	Dec-16	50000	98,420	2	529,519,979	541,773
8	Jan-17	200	2,711,396	27,989	2,711,396	27,989
8	Jan-17	400	14,737,524	47,453	17,448,920	75,442
8	Jan-17	800	85,708,231	142,651	103,157,151	218,093

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
8	Jan-17	1000	57,386,936	63,958	160,544,087	282,051
8	Jan-17	2000	275,447,494	194,082	435,991,581	476,133
8	Jan-17	3000	125,632,641	52,617	561,624,222	528,750
8	Jan-17	4000	35,420,158	10,380	597,044,380	539,130
8	Jan-17	5000	10,048,904	2,244	607,093,284	541,374
8	Jan-17	10000	6,158,591	992	613,251,875	542,366
8	Jan-17	25000	486,586	37	613,738,461	542,403
8	Jan-17	50000	34,740	1	613,773,201	542,404
8	Feb-17	200	3,680,923	37,058	3,680,923	37,058
8	Feb-17	400	22,489,355	72,402	26,170,278	109,460
8	Feb-17	800	109,722,771	185,083	135,893,049	294,543
8	Feb-17	1000	64,044,251	71,496	199,937,300	366,039
8	Feb-17	2000	209,390,028	153,969	409,327,328	520,008
8	Feb-17	3000	45,942,982	19,428	455,270,310	539,436
8	Feb-17	4000	8,720,421	2,536	463,990,731	541,972
8	Feb-17	5000	2,311,382	504	466,302,113	542,476
8	Feb-17	10000	1,616,902	253	467,919,015	542,729
8	Feb-17	25000	173,500	14	468,092,515	542,743
8	Feb-17	50000	30,720	1	468,123,235	542,744
8	Mar-17	200	3,616,855	37,202	3,616,855	37,202
8	Mar-17	400	21,364,737	68,620	24,981,592	105,822
8	Mar-17	800	110,729,398	186,134	135,710,990	291,956
8	Mar-17	1000	66,709,117	74,400	202,420,107	366,356
8	Mar-17	2000	213,128,448	157,059	415,548,555	523,415
8	Mar-17	3000	43,237,460	18,298	458,786,015	541,713
8	Mar-17	4000	7,749,713	2,238	466,535,728	543,951
8	Mar-17	5000	2,207,752	482	468,743,480	544,433
8	Mar-17	10000	1,706,176	268	470,449,656	544,701
8	Mar-17	25000	206,818	17	470,656,474	544,718
8	Mar-17	50000	34,140	1	470,690,614	544,719
8	Apr-17	200	3,956,937	40,251	3,956,937	40,251
8	Apr-17	400	25,093,965	80,824	29,050,902	121,075
8	Apr-17	800	123,687,919	208,369	152,738,821	329,444
8	Apr-17	1000	68,994,940	76,981	221,733,761	406,425
8	Apr-17	2000	165,738,596	125,450	387,472,357	531,875
8	Apr-17	3000	23,553,927	9,861	411,026,284	541,736
8	Apr-17	4000	4,356,941	1,238	415,383,225	542,974
8	Apr-17	5000	1,633,550	362	417,016,775	543,336
8	Apr-17	10000	1,243,504	198	418,260,279	543,534
8	Apr-17	25000	240,731	17	418,501,010	543,551
8	Apr-17	50000	32,520	1	418,533,530	543,552
8	May-17	200	2,877,019	31,847	2,877,019	31,847
8	May-17	400	16,393,993	53,010	19,271,012	84,857
8	May-17	800	101,151,029	167,408	120,422,041	252,265

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
8	May-17	1000	72,811,159	81,235	193,233,200	333,500
8	May-17	2000	251,514,012	184,567	444,747,212	518,067
8	May-17	3000	56,558,130	23,574	501,305,342	541,641
8	May-17	4000	12,217,659	3,491	513,523,001	545,132
8	May-17	5000	3,781,720	824	517,304,721	545,956
8	May-17	10000	3,233,731	513	520,538,452	546,469
8	May-17	25000	528,947	40	521,067,399	546,509
8	May-17	50000	45,300	1	521,112,699	546,510
8	Jun-17	200	2,009,352	24,266	2,009,352	24,266
8	Jun-17	400	9,888,827	32,173	11,898,179	56,439
8	Jun-17	800	70,539,359	115,163	82,437,538	171,602
8	Jun-17	1000	63,034,380	70,218	145,471,918	241,820
8	Jun-17	2000	339,273,067	239,682	484,744,985	481,502
8	Jun-17	3000	129,835,680	54,258	614,580,665	535,760
8	Jun-17	4000	32,781,120	9,472	647,361,785	545,232
8	Jun-17	5000	9,315,526	2,055	656,677,311	547,287
8	Jun-17	10000	6,813,319	1,071	663,490,630	548,358
8	Jun-17	25000	709,402	53	664,200,032	548,411
8	Jun-17	50000	52,720	2	664,252,752	548,413
8	Jun-17	100000	51,300	2	664,304,052	548,415
8	Jul-17	200	1,613,283	20,686	1,613,283	20,686
8	Jul-17	400	7,561,063	24,810	9,174,346	45,496
8	Jul-17	800	58,210,652	94,974	67,384,998	140,470
8	Jul-17	1000	55,926,108	62,337	123,311,106	202,807
8	Jul-17	2000	365,802,788	253,736	489,113,894	456,543
8	Jul-17	3000	176,651,279	73,427	665,765,173	529,970
8	Jul-17	4000	46,856,719	13,511	712,621,892	543,481
8	Jul-17	5000	13,649,008	3,010	726,270,900	546,491
8	Jul-17	10000	9,302,374	1,473	735,573,274	547,964
8	Jul-17	25000	796,598	61	736,369,872	548,025
8	Jul-17	50000	100,800	3	736,470,672	548,028
8	Aug-17	200	1,488,512	18,952	1,488,512	18,952
8	Aug-17	400	6,741,097	22,028	8,229,609	40,980
8	Aug-17	800	53,383,185	86,631	61,612,794	127,611
8	Aug-17	1000	53,175,363	59,164	114,788,157	186,775
8	Aug-17	2000	373,969,769	257,996	488,757,926	444,771
8	Aug-17	3000	199,069,922	82,906	687,827,848	527,677
8	Aug-17	4000	55,815,151	16,221	743,642,999	543,898
8	Aug-17	5000	16,468,283	3,647	760,111,282	547,545
8	Aug-17	10000	10,996,458	1,740	771,107,740	549,285
8	Aug-17	25000	939,493	73	772,047,233	549,358
8	Aug-17	50000	133,220	4	772,180,453	549,362
8	Sep-17	200	1,627,573	19,247	1,627,573	19,247
8	Sep-17	400	8,923,766	28,702	10,551,339	47,949

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
8	Sep-17	800	73,340,679	119,290	83,892,018	167,239
8	Sep-17	1000	66,293,733	73,730	150,185,751	240,969
8	Sep-17	2000	343,611,959	244,045	493,797,710	485,014
8	Sep-17	3000	120,829,416	50,830	614,627,126	535,844
8	Sep-17	4000	28,441,330	8,260	643,068,456	544,104
8	Sep-17	5000	8,178,301	1,818	651,246,757	545,922
8	Sep-17	10000	5,771,977	920	657,018,734	546,842
8	Sep-17	25000	537,026	40	657,555,760	546,882
8	Sep-17	50000	99,440	3	657,655,200	546,885
9	Oct-16	200	1,289,209	24,622	1,289,209	24,622
9	Oct-16	400	2,421,048	8,315	3,710,257	32,937
9	Oct-16	800	5,914,598	10,170	9,624,855	43,107
9	Oct-16	1000	3,226,400	3,595	12,851,255	46,702
9	Oct-16	2000	16,250,992	11,339	29,102,247	58,041
9	Oct-16	3000	13,774,624	5,618	42,876,871	63,659
9	Oct-16	4000	11,511,104	3,334	54,387,975	66,993
9	Oct-16	5000	9,784,272	2,194	64,172,247	69,187
9	Oct-16	10000	38,455,349	5,433	102,627,596	74,620
9	Oct-16	25000	56,137,174	3,752	158,764,770	78,372
9	Oct-16	50000	25,923,881	772	184,688,651	79,144
9	Oct-16	100000	16,188,638	241	200,877,289	79,385
9	Oct-16	250000	9,751,912	72	210,629,201	79,457
9	Oct-16	500000	2,185,576	8	212,814,777	79,465
9	Nov-16	200	1,478,070	26,197	1,478,070	26,197
9	Nov-16	400	2,719,740	9,374	4,197,810	35,571
9	Nov-16	800	6,484,258	11,263	10,682,068	46,834
9	Nov-16	1000	3,345,364	3,739	14,027,432	50,573
9	Nov-16	2000	14,847,452	10,456	28,874,884	61,029
9	Nov-16	3000	12,141,472	4,954	41,016,356	65,983
9	Nov-16	4000	10,036,478	2,903	51,052,834	68,886
9	Nov-16	5000	8,745,660	1,957	59,798,494	70,843
9	Nov-16	10000	34,511,653	4,884	94,310,147	75,727
9	Nov-16	25000	44,099,688	2,972	138,409,835	78,699
9	Nov-16	50000	19,263,219	567	157,673,054	79,266
9	Nov-16	100000	13,085,225	192	170,758,279	79,458
9	Nov-16	250000	7,083,449	54	177,841,728	79,512
9	Nov-16	500000	3,204,077	10	181,045,805	79,522
9	Dec-16	200	1,511,156	24,647	1,511,156	24,647
9	Dec-16	400	2,506,697	8,614	4,017,853	33,261
9	Dec-16	800	6,368,822	10,946	10,386,675	44,207
9	Dec-16	1000	3,635,044	4,048	14,021,719	48,255
9	Dec-16	2000	16,415,048	11,513	30,436,767	59,768
9	Dec-16	3000	13,493,892	5,503	43,930,659	65,271
9	Dec-16	4000	10,914,301	3,143	54,844,960	68,414
9	Dec-16	5000	9,228,046	2,068	64,073,006	70,482

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
9	Dec-16	10000	36,176,938	5,146	100,249,944	75,628
9	Dec-16	25000	46,309,919	3,106	146,559,863	78,734
9	Dec-16	50000	20,991,208	621	167,551,071	79,355
9	Dec-16	100000	13,056,545	195	180,607,616	79,550
9	Dec-16	250000	8,554,076	64	189,161,692	79,614
9	Dec-16	500000	2,843,894	9	192,005,586	79,623
9	Jan-17	200	1,054,649	23,826	1,054,649	23,826
9	Jan-17	400	2,323,895	8,002	3,378,544	31,828
9	Jan-17	800	6,098,091	10,452	9,476,635	42,280
9	Jan-17	1000	3,329,927	3,725	12,806,562	46,005
9	Jan-17	2000	17,172,756	11,992	29,979,318	57,997
9	Jan-17	3000	14,764,656	6,008	44,743,974	64,005
9	Jan-17	4000	12,047,857	3,482	56,791,831	67,487
9	Jan-17	5000	9,970,875	2,226	66,762,706	69,713
9	Jan-17	10000	39,223,869	5,565	105,986,575	75,278
9	Jan-17	25000	51,357,074	3,430	157,343,649	78,708
9	Jan-17	50000	23,457,184	691	180,800,833	79,399
9	Jan-17	100000	14,540,689	218	195,341,522	79,617
9	Jan-17	250000	9,301,700	68	204,643,222	79,685
9	Jan-17	500000	1,572,294	5	206,215,516	79,690
9	Jan-17	Over 500k	678,629	1	206,894,145	79,691
9	Feb-17	200	1,533,218	25,727	1,533,218	25,727
9	Feb-17	400	2,491,506	8,547	4,024,724	34,274
9	Feb-17	800	6,483,543	11,155	10,508,267	45,429
9	Feb-17	1000	3,481,253	3,871	13,989,520	49,300
9	Feb-17	2000	16,151,175	11,342	30,140,695	60,642
9	Feb-17	3000	13,031,898	5,333	43,172,593	65,975
9	Feb-17	4000	10,524,562	3,039	53,697,155	69,014
9	Feb-17	5000	9,180,283	2,040	62,877,438	71,054
9	Feb-17	10000	34,512,211	4,925	97,389,649	75,979
9	Feb-17	25000	42,309,950	2,855	139,699,599	78,834
9	Feb-17	50000	18,963,866	558	158,663,465	79,392
9	Feb-17	100000	12,093,979	175	170,757,444	79,567
9	Feb-17	250000	6,964,620	54	177,722,064	79,621
9	Feb-17	500000	1,784,677	6	179,506,741	79,627
9	Mar-17	200	1,414,150	25,161	1,414,150	25,161
9	Mar-17	400	2,546,515	8,730	3,960,665	33,891
9	Mar-17	800	6,462,645	11,123	10,423,310	45,014
9	Mar-17	1000	3,426,522	3,820	13,849,832	48,834
9	Mar-17	2000	16,139,926	11,274	29,989,758	60,108
9	Mar-17	3000	13,040,660	5,330	43,030,418	65,438
9	Mar-17	4000	10,792,956	3,138	53,823,374	68,576
9	Mar-17	5000	9,311,281	2,081	63,134,655	70,657
9	Mar-17	10000	35,760,537	5,067	98,895,192	75,724
9	Mar-17	25000	47,044,125	3,162	145,939,317	78,886

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
9	Mar-17	50000	21,351,278	627	167,290,595	79,513
9	Mar-17	100000	13,406,916	198	180,697,511	79,711
9	Mar-17	250000	8,659,760	68	189,357,271	79,779
9	Mar-17	500000	2,377,370	7	191,734,641	79,786
9	Apr-17	200	1,614,316	26,154	1,614,316	26,154
9	Apr-17	400	2,643,484	9,048	4,257,800	35,202
9	Apr-17	800	6,407,906	11,048	10,665,706	46,250
9	Apr-17	1000	3,292,730	3,697	13,958,436	49,947
9	Apr-17	2000	15,705,259	10,977	29,663,695	60,924
9	Apr-17	3000	12,499,620	5,117	42,163,315	66,041
9	Apr-17	4000	10,362,520	3,001	52,525,835	69,042
9	Apr-17	5000	8,923,588	2,002	61,449,423	71,044
9	Apr-17	10000	34,271,119	4,868	95,720,542	75,912
9	Apr-17	25000	45,858,191	3,107	141,578,733	79,019
9	Apr-17	50000	19,904,746	597	161,483,479	79,616
9	Apr-17	100000	13,288,054	195	174,771,533	79,811
9	Apr-17	250000	7,694,427	55	182,465,960	79,866
9	Apr-17	500000	1,203,267	4	183,669,227	79,870
9	Apr-17	Over 500k	799,200	1	184,468,427	79,871
9	May-17	200	1,322,307	24,735	1,322,307	24,735
9	May-17	400	2,447,643	8,415	3,769,950	33,150
9	May-17	800	5,932,833	10,187	9,702,783	43,337
9	May-17	1000	3,154,039	3,528	12,856,822	46,865
9	May-17	2000	16,032,829	11,184	28,889,651	58,049
9	May-17	3000	13,957,628	5,687	42,847,279	63,736
9	May-17	4000	11,543,958	3,335	54,391,237	67,071
9	May-17	5000	10,495,486	2,343	64,886,723	69,414
9	May-17	10000	38,811,785	5,505	103,698,508	74,919
9	May-17	25000	60,079,216	3,970	163,777,724	78,889
9	May-17	50000	28,066,789	835	191,844,513	79,724
9	May-17	100000	16,714,177	247	208,558,690	79,971
9	May-17	250000	10,628,411	80	219,187,101	80,051
9	May-17	500000	4,084,443	14	223,271,544	80,065
9	Jun-17	200	1,448,688	23,659	1,448,688	23,659
9	Jun-17	400	2,212,605	7,629	3,661,293	31,288
9	Jun-17	800	5,485,897	9,373	9,147,190	40,661
9	Jun-17	1000	3,074,809	3,434	12,221,999	44,095
9	Jun-17	2000	16,656,835	11,506	28,878,834	55,601
9	Jun-17	3000	15,278,138	6,237	44,156,972	61,838
9	Jun-17	4000	12,904,975	3,737	57,061,947	65,575
9	Jun-17	5000	11,793,666	2,626	68,855,613	68,201
9	Jun-17	10000	42,366,502	5,988	111,222,115	74,189
9	Jun-17	25000	69,147,957	4,554	180,370,072	78,743
9	Jun-17	50000	34,661,829	1,025	215,031,901	79,768
9	Jun-17	100000	21,310,941	313	236,342,842	80,081

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
9	Jun-17	250000	13,217,420	96	249,560,262	80,177
9	Jun-17	500000	4,966,143	15	254,526,405	80,192
9	Jul-17	200	745,728	23,866	745,728	23,866
9	Jul-17	400	2,079,646	7,180	2,825,374	31,046
9	Jul-17	800	5,168,084	8,828	7,993,458	39,874
9	Jul-17	1000	3,002,078	3,345	10,995,536	43,219
9	Jul-17	2000	16,973,226	11,723	27,968,762	54,942
9	Jul-17	3000	15,870,684	6,462	43,839,446	61,404
9	Jul-17	4000	13,779,007	3,961	57,618,453	65,365
9	Jul-17	5000	11,663,470	2,604	69,281,923	67,969
9	Jul-17	10000	43,762,601	6,220	113,044,524	74,189
9	Jul-17	25000	68,946,942	4,541	181,991,466	78,730
9	Jul-17	50000	33,869,035	1,010	215,860,501	79,740
9	Jul-17	100000	22,003,931	333	237,864,432	80,073
9	Jul-17	250000	12,788,854	93	250,653,286	80,166
9	Jul-17	500000	3,438,841	10	254,092,127	80,176
9	Jul-17	Over 500k	585,000	1	254,677,127	80,177
9	Aug-17	200	919,825	23,228	919,825	23,228
9	Aug-17	400	2,068,506	7,140	2,988,331	30,368
9	Aug-17	800	4,935,355	8,441	7,923,686	38,809
9	Aug-17	1000	3,006,628	3,365	10,930,314	42,174
9	Aug-17	2000	16,782,017	11,572	27,712,331	53,746
9	Aug-17	3000	16,590,637	6,746	44,302,968	60,492
9	Aug-17	4000	14,028,919	4,052	58,331,887	64,544
9	Aug-17	5000	12,494,591	2,798	70,826,478	67,342
9	Aug-17	10000	45,385,216	6,430	116,211,694	73,772
9	Aug-17	25000	74,512,329	4,892	190,724,023	78,664
9	Aug-17	50000	38,276,168	1,138	229,000,191	79,802
9	Aug-17	100000	24,552,475	367	253,552,666	80,169
9	Aug-17	250000	15,687,879	112	269,240,545	80,281
9	Aug-17	500000	2,929,949	9	272,170,494	80,290
9	Aug-17	Over 500k	1,648,685	2	273,819,179	80,292
9	Sep-17	200	1,338,720	23,690	1,338,720	23,690
9	Sep-17	400	2,230,726	7,679	3,569,446	31,369
9	Sep-17	800	5,419,702	9,270	8,989,148	40,639
9	Sep-17	1000	3,132,975	3,495	12,122,123	44,134
9	Sep-17	2000	16,935,446	11,709	29,057,569	55,843
9	Sep-17	3000	15,564,989	6,337	44,622,558	62,180
9	Sep-17	4000	12,999,230	3,755	57,621,788	65,935
9	Sep-17	5000	11,332,073	2,528	68,953,861	68,463
9	Sep-17	10000	42,355,569	6,006	111,309,430	74,469
9	Sep-17	25000	66,963,101	4,410	178,272,531	78,879
9	Sep-17	50000	32,033,084	953	210,305,615	79,832
9	Sep-17	100000	22,129,403	331	232,435,018	80,163
9	Sep-17	250000	11,730,368	87	244,165,386	80,250

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
9	Sep-17	500000	3,656,112	10	247,821,498	80,260
10	Oct-16	200	57,011	1,911	57,011	1,911
10	Oct-16	400	19,154	69	76,165	1,980
10	Oct-16	800	45,913	78	122,078	2,058
10	Oct-16	1000	17,628	20	139,706	2,078
10	Oct-16	2000	42,483	31	182,189	2,109
10	Oct-16	3000	38,096	15	220,285	2,124
10	Oct-16	4000	21,331	6	241,616	2,130
10	Oct-16	5000	35,229	8	276,845	2,138
10	Oct-16	10000	29,199	4	306,044	2,142
10	Oct-16	25000	10,271	1	316,315	2,143
10	Nov-16	200	60,555	1,976	60,555	1,976
10	Nov-16	400	20,909	73	81,464	2,049
10	Nov-16	800	37,755	65	119,219	2,114
10	Nov-16	1000	16,079	20	135,298	2,134
10	Nov-16	2000	55,204	41	190,502	2,175
10	Nov-16	3000	38,595	14	229,097	2,189
10	Nov-16	4000	17,459	6	246,556	2,195
10	Nov-16	5000	29,775	7	276,331	2,202
10	Nov-16	10000	55,256	8	331,587	2,210
10	Dec-16	200	52,323	1,974	52,323	1,974
10	Dec-16	400	18,803	64	71,126	2,038
10	Dec-16	800	42,637	73	113,763	2,111
10	Dec-16	1000	11,259	13	125,022	2,124
10	Dec-16	2000	73,140	47	198,162	2,171
10	Dec-16	3000	58,453	22	256,615	2,193
10	Dec-16	4000	41,051	14	297,666	2,207
10	Dec-16	5000	36,186	9	333,852	2,216
10	Dec-16	10000	53,337	7	387,189	2,223
10	Dec-16	25000	12,575	1	399,764	2,224
10	Jan-17	200	65,155	1,939	65,155	1,939
10	Jan-17	400	17,202	60	82,357	1,999
10	Jan-17	800	45,222	75	127,579	2,074
10	Jan-17	1000	15,564	17	143,143	2,091
10	Jan-17	2000	70,816	50	213,959	2,141
10	Jan-17	3000	64,112	26	278,071	2,167
10	Jan-17	4000	48,542	13	326,613	2,180
10	Jan-17	5000	18,391	4	345,004	2,184
10	Jan-17	10000	106,832	15	451,836	2,199
10	Jan-17	25000	14,824	1	466,660	2,200
10	Feb-17	200	62,257	2,054	62,257	2,054
10	Feb-17	400	17,366	62	79,623	2,116
10	Feb-17	800	34,911	60	114,534	2,176
10	Feb-17	1000	17,820	20	132,354	2,196
10	Feb-17	2000	55,469	40	187,823	2,236

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
10	Feb-17	3000	49,741	19	237,564	2,255
10	Feb-17	4000	28,039	8	265,603	2,263
10	Feb-17	5000	8,822	2	274,425	2,265
10	Feb-17	10000	50,108	7	324,533	2,272
10	Feb-17	25000	14,137	1	338,670	2,273
10	Mar-17	200	70,403	2,169	70,403	2,169
10	Mar-17	400	20,310	72	90,713	2,241
10	Mar-17	800	32,736	59	123,449	2,300
10	Mar-17	1000	15,007	18	138,456	2,318
10	Mar-17	2000	68,658	45	207,114	2,363
10	Mar-17	3000	61,595	25	268,709	2,388
10	Mar-17	4000	13,268	3	281,977	2,391
10	Mar-17	5000	4,043	1	286,020	2,392
10	Mar-17	10000	49,844	8	335,864	2,400
10	Mar-17	25000	25,171	2	361,035	2,402
10	Apr-17	200	65,680	2,219	65,680	2,219
10	Apr-17	400	25,560	93	91,240	2,312
10	Apr-17	800	28,526	47	119,766	2,359
10	Apr-17	1000	11,584	13	131,350	2,372
10	Apr-17	2000	45,901	35	177,251	2,407
10	Apr-17	3000	26,958	11	204,209	2,418
10	Apr-17	4000	21,107	6	225,316	2,424
10	Apr-17	5000	4,370	1	229,686	2,425
10	Apr-17	10000	57,470	8	287,156	2,433
10	Apr-17	25000	10,095	1	297,251	2,434
10	May-17	200	68,016	2,185	68,016	2,185
10	May-17	400	25,245	87	93,261	2,272
10	May-17	800	38,960	67	132,221	2,339
10	May-17	1000	14,474	15	146,695	2,354
10	May-17	2000	67,046	50	213,741	2,404
10	May-17	3000	29,947	12	243,688	2,416
10	May-17	4000	31,455	7	275,143	2,423
10	May-17	5000	17,092	5	292,235	2,428
10	May-17	10000	42,268	6	334,503	2,434
10	May-17	25000	22,470	2	356,973	2,436
10	Jun-17	200	64,671	2,169	64,671	2,169
10	Jun-17	400	18,567	64	83,238	2,233
10	Jun-17	800	37,605	64	120,843	2,297
10	Jun-17	1000	16,117	16	136,960	2,313
10	Jun-17	2000	93,046	64	230,006	2,377
10	Jun-17	3000	53,749	23	283,755	2,400
10	Jun-17	4000	33,483	8	317,238	2,408
10	Jun-17	5000	9,347	2	326,585	2,410
10	Jun-17	10000	64,302	10	390,887	2,420
10	Jun-17	25000	35,544	3	426,431	2,423

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
10	Jul-17	200	58,375	2,099	58,375	2,099
10	Jul-17	400	21,762	73	80,137	2,172
10	Jul-17	800	36,290	61	116,427	2,233
10	Jul-17	1000	15,983	18	132,410	2,251
10	Jul-17	2000	103,143	71	235,553	2,322
10	Jul-17	3000	66,958	27	302,511	2,349
10	Jul-17	4000	26,684	9	329,195	2,358
10	Jul-17	5000	27,314	5	356,509	2,363
10	Jul-17	10000	41,993	6	398,502	2,369
10	Jul-17	25000	33,893	3	432,395	2,372
10	Jul-17	50000	27,940	1	460,335	2,373
10	Aug-17	200	63,719	2,080	63,719	2,080
10	Aug-17	400	20,624	75	84,343	2,155
10	Aug-17	800	43,088	75	127,431	2,230
10	Aug-17	1000	21,748	24	149,179	2,254
10	Aug-17	2000	101,334	69	250,513	2,323
10	Aug-17	3000	71,576	30	322,089	2,353
10	Aug-17	4000	27,300	7	349,389	2,360
10	Aug-17	5000	21,939	5	371,328	2,365
10	Aug-17	10000	59,545	9	430,873	2,374
10	Aug-17	25000	38,477	3	469,350	2,377
10	Aug-17	50000	31,102	1	500,452	2,378
10	Sep-17	200	55,418	2,045	55,418	2,045
10	Sep-17	400	22,238	75	77,656	2,120
10	Sep-17	800	45,876	78	123,532	2,198
10	Sep-17	1000	22,120	25	145,652	2,223
10	Sep-17	2000	77,084	54	222,736	2,277
10	Sep-17	3000	67,169	28	289,905	2,305
10	Sep-17	4000	6,302	3	296,207	2,308
10	Sep-17	5000	26,193	5	322,400	2,313
10	Sep-17	10000	34,611	5	357,011	2,318
10	Sep-17	25000	11,925	1	368,936	2,319
10	Sep-17	50000	34,292	1	403,228	2,320
11	Oct-16	200	4,392	185	4,392	185
11	Oct-16	400	3,239	12	7,631	197
11	Oct-16	800	3,426	6	11,057	203
11	Oct-16	1000	2,767	3	13,824	206
11	Oct-16	2000	24,769	18	38,593	224
11	Oct-16	3000	32,434	12	71,027	236
11	Oct-16	4000	34,218	11	105,245	247
11	Oct-16	5000	36,247	8	141,492	255
11	Oct-16	10000	267,087	35	408,579	290
11	Oct-16	25000	353,775	24	762,354	314
11	Oct-16	50000	153,000	5	915,354	319
11	Nov-16	200	3,837	188	3,837	188

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
11	Nov-16	400	2,892	11	6,729	199
11	Nov-16	800	6,105	11	12,834	210
11	Nov-16	1000	5,470	6	18,304	216
11	Nov-16	2000	15,763	10	34,067	226
11	Nov-16	3000	33,378	14	67,445	240
11	Nov-16	4000	25,910	8	93,355	248
11	Nov-16	5000	40,399	9	133,754	257
11	Nov-16	10000	258,455	35	392,209	292
11	Nov-16	25000	374,699	26	766,908	318
11	Nov-16	50000	137,760	5	904,668	323
11	Dec-16	200	4,361	190	4,361	190
11	Dec-16	400	3,307	12	7,668	202
11	Dec-16	800	4,435	8	12,103	210
11	Dec-16	1000	6,088	7	18,191	217
11	Dec-16	2000	32,361	22	50,552	239
11	Dec-16	3000	47,971	20	98,523	259
11	Dec-16	4000	28,139	8	126,662	267
11	Dec-16	5000	29,501	7	156,163	274
11	Dec-16	10000	198,298	28	354,461	302
11	Dec-16	25000	203,882	14	558,343	316
11	Dec-16	50000	30,440	1	588,783	317
11	Jan-17	200	6,478	229	6,478	229
11	Jan-17	400	4,751	18	11,229	247
11	Jan-17	800	7,928	12	19,157	259
11	Jan-17	1000	5,433	6	24,590	265
11	Jan-17	2000	27,497	19	52,087	284
11	Jan-17	3000	18,263	8	70,350	292
11	Jan-17	4000	31,955	9	102,305	301
11	Jan-17	5000	4,480	1	106,785	302
11	Jan-17	10000	64,051	9	170,836	311
11	Jan-17	25000	69,460	5	240,296	316
11	Feb-17	200	5,706	231	5,706	231
11	Feb-17	400	3,425	14	9,131	245
11	Feb-17	800	6,551	11	15,682	256
11	Feb-17	1000	4,615	5	20,297	261
11	Feb-17	2000	31,695	23	51,992	284
11	Feb-17	3000	31,623	13	83,615	297
11	Feb-17	4000	13,301	4	96,916	301
11	Feb-17	5000	13,220	3	110,136	304
11	Feb-17	10000	49,259	7	159,395	311
11	Feb-17	25000	64,240	5	223,635	316
11	Feb-17	50000	25,000	1	248,635	317
11	Mar-17	200	5,210	204	5,210	204
11	Mar-17	400	3,909	15	9,119	219
11	Mar-17	800	6,650	11	15,769	230

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
11	Mar-17	1000	7,639	9	23,408	239
11	Mar-17	2000	18,434	13	41,842	252
11	Mar-17	3000	42,018	18	83,860	270
11	Mar-17	4000	48,491	14	132,351	284
11	Mar-17	5000	22,441	5	154,792	289
11	Mar-17	10000	100,952	15	255,744	304
11	Mar-17	25000	184,210	12	439,954	316
11	Apr-17	200	4,632	163	4,632	163
11	Apr-17	400	3,342	13	7,974	176
11	Apr-17	800	9,471	17	17,445	193
11	Apr-17	1000	3,400	4	20,845	197
11	Apr-17	2000	46,322	31	67,167	228
11	Apr-17	3000	48,026	20	115,193	248
11	Apr-17	4000	65,823	19	181,016	267
11	Apr-17	5000	40,596	9	221,612	276
11	Apr-17	10000	193,480	29	415,092	305
11	Apr-17	25000	188,470	12	603,562	317
11	Apr-17	50000	53,960	2	657,522	319
11	May-17	200	3,343	106	3,343	106
11	May-17	400	4,953	17	8,296	123
11	May-17	800	10,659	19	18,955	142
11	May-17	1000	5,562	6	24,517	148
11	May-17	2000	48,326	32	72,843	180
11	May-17	3000	57,619	23	130,462	203
11	May-17	4000	80,334	23	210,796	226
11	May-17	5000	80,461	18	291,257	244
11	May-17	10000	305,167	42	596,424	286
11	May-17	25000	537,797	34	1,134,221	320
11	May-17	50000	162,880	5	1,297,101	325
11	Jun-17	200	1,782	66	1,782	66
11	Jun-17	400	3,060	11	4,842	77
11	Jun-17	800	8,608	15	13,450	92
11	Jun-17	1000	4,583	5	18,033	97
11	Jun-17	2000	45,722	30	63,755	127
11	Jun-17	3000	44,670	19	108,425	146
11	Jun-17	4000	57,416	16	165,841	162
11	Jun-17	5000	72,305	17	238,146	179
11	Jun-17	10000	495,590	66	733,736	245
11	Jun-17	25000	993,389	65	1,727,125	310
11	Jun-17	50000	347,017	10	2,074,142	320
11	Jul-17	200	2,488	67	2,488	67
11	Jul-17	400	2,720	10	5,208	77
11	Jul-17	800	6,005	11	11,213	88
11	Jul-17	1000	2,633	3	13,846	91
11	Jul-17	2000	35,161	23	49,007	114

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
11	Jul-17	3000	60,522	25	109,529	139
11	Jul-17	4000	97,892	28	207,421	167
11	Jul-17	5000	72,542	16	279,963	183
11	Jul-17	10000	492,100	71	772,063	254
11	Jul-17	25000	938,915	58	1,710,978	312
11	Jul-17	50000	229,552	8	1,940,530	320
11	Aug-17	200	2,584	72	2,584	72
11	Aug-17	400	4,304	15	6,888	87
11	Aug-17	800	4,562	8	11,450	95
11	Aug-17	1000	5,291	6	16,741	101
11	Aug-17	2000	40,500	27	57,241	128
11	Aug-17	3000	60,916	25	118,157	153
11	Aug-17	4000	92,118	27	210,275	180
11	Aug-17	5000	68,908	16	279,183	196
11	Aug-17	10000	446,529	62	725,712	258
11	Aug-17	25000	918,049	61	1,643,761	319
11	Aug-17	50000	89,550	2	1,733,311	321
11	Sep-17	200	2,335	92	2,335	92
11	Sep-17	400	3,085	13	5,420	105
11	Sep-17	800	12,911	21	18,331	126
11	Sep-17	1000	6,246	7	24,577	133
11	Sep-17	2000	35,812	23	60,389	156
11	Sep-17	3000	85,018	34	145,407	190
11	Sep-17	4000	48,018	14	193,425	204
11	Sep-17	5000	87,653	20	281,078	224
11	Sep-17	10000	386,408	55	667,486	279
11	Sep-17	25000	604,866	37	1,272,352	316
11	Sep-17	50000	151,888	5	1,424,240	321
12	Oct-16	200	43,823	520	43,823	520
12	Oct-16	400	118,604	400	162,427	920
12	Oct-16	800	381,397	652	543,824	1,572
12	Oct-16	1000	195,608	219	739,432	1,791
12	Oct-16	2000	917,661	637	1,657,093	2,428
12	Oct-16	3000	807,266	329	2,464,359	2,757
12	Oct-16	4000	677,062	196	3,141,421	2,953
12	Oct-16	5000	632,732	142	3,774,153	3,095
12	Oct-16	10000	2,316,736	333	6,090,889	3,428
12	Oct-16	25000	3,054,528	199	9,145,417	3,627
12	Oct-16	50000	2,086,584	62	11,232,001	3,689
12	Oct-16	100000	817,240	12	12,049,241	3,701
12	Oct-16	250000	616,500	5	12,665,741	3,706
12	Nov-16	200	14,009	681	14,009	681
12	Nov-16	400	162,952	563	176,961	1,244
12	Nov-16	800	399,607	706	576,568	1,950
12	Nov-16	1000	208,144	247	784,712	2,197

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
12	Nov-16	2000	771,637	566	1,556,349	2,763
12	Nov-16	3000	667,784	277	2,224,133	3,040
12	Nov-16	4000	545,919	157	2,770,052	3,197
12	Nov-16	5000	482,538	108	3,252,590	3,305
12	Nov-16	10000	1,470,221	211	4,722,811	3,516
12	Nov-16	25000	1,962,789	131	6,685,600	3,647
12	Nov-16	50000	1,203,269	38	7,888,869	3,685
12	Nov-16	100000	624,800	9	8,513,669	3,694
12	Nov-16	250000	250,740	2	8,764,409	3,696
12	Dec-16	200	47,916	549	47,916	549
12	Dec-16	400	134,256	451	182,172	1,000
12	Dec-16	800	371,587	647	553,759	1,647
12	Dec-16	1000	228,444	255	782,203	1,902
12	Dec-16	2000	932,759	661	1,714,962	2,563
12	Dec-16	3000	721,257	295	2,436,219	2,858
12	Dec-16	4000	707,057	204	3,143,276	3,062
12	Dec-16	5000	518,062	117	3,661,338	3,179
12	Dec-16	10000	2,030,496	296	5,691,834	3,475
12	Dec-16	25000	2,570,768	171	8,262,602	3,646
12	Dec-16	50000	1,171,128	37	9,433,730	3,683
12	Dec-16	100000	888,960	13	10,322,690	3,696
12	Dec-16	250000	160,500	1	10,483,190	3,697
12	Jan-17	200	39,484	497	39,484	497
12	Jan-17	400	119,118	409	158,602	906
12	Jan-17	800	333,666	579	492,268	1,485
12	Jan-17	1000	206,118	229	698,386	1,714
12	Jan-17	2000	966,029	681	1,664,415	2,395
12	Jan-17	3000	871,486	355	2,535,901	2,750
12	Jan-17	4000	695,302	199	3,231,203	2,949
12	Jan-17	5000	598,511	133	3,829,714	3,082
12	Jan-17	10000	2,262,373	329	6,092,087	3,411
12	Jan-17	25000	3,242,703	215	9,334,790	3,626
12	Jan-17	50000	1,577,717	49	10,912,507	3,675
12	Jan-17	100000	870,220	14	11,782,727	3,689
12	Jan-17	250000	281,940	2	12,064,667	3,691
12	Feb-17	200	49,781	576	49,781	576
12	Feb-17	400	146,656	498	196,437	1,074
12	Feb-17	800	393,750	670	590,187	1,744
12	Feb-17	1000	197,289	220	787,476	1,964
12	Feb-17	2000	891,896	628	1,679,372	2,592
12	Feb-17	3000	736,267	303	2,415,639	2,895
12	Feb-17	4000	654,148	188	3,069,787	3,083
12	Feb-17	5000	576,764	129	3,646,551	3,212
12	Feb-17	10000	1,771,824	263	5,418,375	3,475
12	Feb-17	25000	2,411,504	164	7,829,879	3,639

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
12	Feb-17	50000	1,128,177	36	8,958,056	3,675
12	Feb-17	100000	782,960	12	9,741,016	3,687
12	Feb-17	250000	153,000	1	9,894,016	3,688
12	Mar-17	200	48,242	561	48,242	561
12	Mar-17	400	149,014	502	197,256	1,063
12	Mar-17	800	405,040	695	602,296	1,758
12	Mar-17	1000	220,715	247	823,011	2,005
12	Mar-17	2000	891,419	635	1,714,430	2,640
12	Mar-17	3000	699,270	289	2,413,700	2,929
12	Mar-17	4000	656,094	189	3,069,794	3,118
12	Mar-17	5000	531,621	120	3,601,415	3,238
12	Mar-17	10000	1,702,946	246	5,304,361	3,484
12	Mar-17	25000	2,238,862	154	7,543,223	3,638
12	Mar-17	50000	1,249,582	38	8,792,805	3,676
12	Mar-17	100000	778,440	11	9,571,245	3,687
12	Mar-17	250000	171,000	1	9,742,245	3,688
12	Apr-17	200	52,856	617	52,856	617
12	Apr-17	400	166,592	568	219,448	1,185
12	Apr-17	800	416,775	722	636,223	1,907
12	Apr-17	1000	222,954	250	859,177	2,157
12	Apr-17	2000	827,017	583	1,686,194	2,740
12	Apr-17	3000	666,317	271	2,352,511	3,011
12	Apr-17	4000	558,051	163	2,910,562	3,174
12	Apr-17	5000	469,397	106	3,379,959	3,280
12	Apr-17	10000	1,611,158	229	4,991,117	3,509
12	Apr-17	25000	2,053,124	136	7,044,241	3,645
12	Apr-17	50000	1,253,824	37	8,298,065	3,682
12	Apr-17	100000	656,800	9	8,954,865	3,691
12	Apr-17	250000	151,500	1	9,106,365	3,692
12	May-17	200	38,785	491	38,785	491
12	May-17	400	133,075	450	171,860	941
12	May-17	800	374,163	642	546,023	1,583
12	May-17	1000	208,273	233	754,296	1,816
12	May-17	2000	954,935	678	1,709,231	2,494
12	May-17	3000	796,089	323	2,505,320	2,817
12	May-17	4000	591,619	171	3,096,939	2,988
12	May-17	5000	651,986	147	3,748,925	3,135
12	May-17	10000	2,043,024	289	5,791,949	3,424
12	May-17	25000	3,002,960	195	8,794,909	3,619
12	May-17	50000	1,905,529	56	10,700,438	3,675
12	May-17	100000	695,360	10	11,395,798	3,685
12	May-17	250000	630,970	5	12,026,768	3,690
12	Jun-17	200	31,206	424	31,206	424
12	Jun-17	400	86,887	289	118,093	713
12	Jun-17	800	305,748	512	423,841	1,225

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
12	Jun-17	1000	196,687	221	620,528	1,446
12	Jun-17	2000	1,015,158	712	1,635,686	2,158
12	Jun-17	3000	940,227	382	2,575,913	2,540
12	Jun-17	4000	773,912	226	3,349,825	2,766
12	Jun-17	5000	643,888	145	3,993,713	2,911
12	Jun-17	10000	2,787,419	402	6,781,132	3,313
12	Jun-17	25000	4,040,562	265	10,821,694	3,578
12	Jun-17	50000	2,934,714	86	13,756,408	3,664
12	Jun-17	100000	1,076,480	16	14,832,888	3,680
12	Jun-17	250000	792,630	6	15,625,518	3,686
12	Jul-17	200	25,393	374	25,393	374
12	Jul-17	400	74,146	247	99,539	621
12	Jul-17	800	249,891	416	349,430	1,037
12	Jul-17	1000	174,595	196	524,025	1,233
12	Jul-17	2000	1,026,906	712	1,550,931	1,945
12	Jul-17	3000	1,019,321	418	2,570,252	2,363
12	Jul-17	4000	847,514	245	3,417,766	2,608
12	Jul-17	5000	811,905	183	4,229,671	2,791
12	Jul-17	10000	3,174,291	457	7,403,962	3,248
12	Jul-17	25000	4,941,667	319	12,345,629	3,567
12	Jul-17	50000	2,949,420	87	15,295,049	3,654
12	Jul-17	100000	1,460,120	22	16,755,169	3,676
12	Jul-17	250000	675,010	5	17,430,179	3,681
12	Aug-17	200	18,282	358	18,282	358
12	Aug-17	400	69,694	236	87,976	594
12	Aug-17	800	227,705	379	315,681	973
12	Aug-17	1000	172,248	193	487,929	1,166
12	Aug-17	2000	1,025,037	712	1,512,966	1,878
12	Aug-17	3000	998,884	407	2,511,850	2,285
12	Aug-17	4000	922,511	267	3,434,361	2,552
12	Aug-17	5000	936,446	210	4,370,807	2,762
12	Aug-17	10000	3,335,240	467	7,706,047	3,229
12	Aug-17	25000	4,850,552	314	12,556,599	3,543
12	Aug-17	50000	3,559,034	104	16,115,633	3,647
12	Aug-17	100000	1,371,060	22	17,486,693	3,669
12	Aug-17	250000	1,161,850	9	18,648,543	3,678
12	Sep-17	200	29,513	406	29,513	406
12	Sep-17	400	82,783	278	112,296	684
12	Sep-17	800	314,471	533	426,767	1,217
12	Sep-17	1000	189,096	213	615,863	1,430
12	Sep-17	2000	989,122	685	1,604,985	2,115
12	Sep-17	3000	987,952	402	2,592,937	2,517
12	Sep-17	4000	719,056	209	3,311,993	2,726
12	Sep-17	5000	797,154	178	4,109,147	2,904
12	Sep-17	10000	2,856,772	408	6,965,919	3,312

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
12	Sep-17	25000	4,137,345	261	11,103,264	3,573
12	Sep-17	50000	2,781,133	79	13,884,397	3,652
12	Sep-17	100000	1,281,900	19	15,166,297	3,671
12	Sep-17	250000	778,230	6	15,944,527	3,677
13	Oct-16	200	14,023	196	14,023	196
13	Oct-16	400	16,706	58	30,729	254
13	Oct-16	800	17,402	29	48,131	283
13	Oct-16	1000	8,813	10	56,944	293
13	Oct-16	2000	54,831	39	111,775	332
13	Oct-16	3000	64,170	27	175,945	359
13	Oct-16	4000	41,088	12	217,033	371
13	Oct-16	5000	22,100	5	239,133	376
13	Oct-16	10000	39,859	5	278,992	381
13	Oct-16	25000	30,600	2	309,592	383
13	Nov-16	200	13,597	195	13,597	195
13	Nov-16	400	16,972	58	30,569	253
13	Nov-16	800	14,557	25	45,126	278
13	Nov-16	1000	13,216	15	58,342	293
13	Nov-16	2000	49,645	36	107,987	329
13	Nov-16	3000	58,815	24	166,802	353
13	Nov-16	4000	60,036	18	226,838	371
13	Nov-16	5000	18,621	4	245,459	375
13	Nov-16	10000	51,221	7	296,680	382
13	Nov-16	25000	19,280	1	315,960	383
13	Dec-16	200	14,759	196	14,759	196
13	Dec-16	400	16,548	59	31,307	255
13	Dec-16	800	16,641	28	47,948	283
13	Dec-16	1000	9,202	11	57,150	294
13	Dec-16	2000	60,019	40	117,169	334
13	Dec-16	3000	53,852	21	171,021	355
13	Dec-16	4000	52,135	15	223,156	370
13	Dec-16	5000	27,281	6	250,437	376
13	Dec-16	10000	54,697	9	305,134	385
13	Dec-16	25000	32,960	2	338,094	387
13	Jan-17	200	13,234	187	13,234	187
13	Jan-17	400	18,422	62	31,656	249
13	Jan-17	800	18,552	33	50,208	282
13	Jan-17	1000	7,900	9	58,108	291
13	Jan-17	2000	49,925	33	108,033	324
13	Jan-17	3000	54,371	23	162,404	347
13	Jan-17	4000	44,068	13	206,472	360
13	Jan-17	5000	40,621	9	247,093	369
13	Jan-17	10000	71,496	11	318,589	380
13	Jan-17	25000	32,400	2	350,989	382
13	Feb-17	200	14,089	200	14,089	200

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
13	Feb-17	400	16,128	56	30,217	256
13	Feb-17	800	16,308	29	46,525	285
13	Feb-17	1000	6,978	8	53,503	293
13	Feb-17	2000	63,027	44	116,530	337
13	Feb-17	3000	51,755	21	168,285	358
13	Feb-17	4000	35,709	10	203,994	368
13	Feb-17	5000	17,734	4	221,728	372
13	Feb-17	10000	59,820	9	281,548	381
13	Feb-17	25000	20,880	1	302,428	382
13	Mar-17	200	14,144	191	14,144	191
13	Mar-17	400	16,743	57	30,887	248
13	Mar-17	800	16,725	30	47,612	278
13	Mar-17	1000	9,547	11	57,159	289
13	Mar-17	2000	60,193	41	117,352	330
13	Mar-17	3000	49,097	20	166,449	350
13	Mar-17	4000	48,304	14	214,753	364
13	Mar-17	5000	35,252	8	250,005	372
13	Mar-17	10000	45,923	7	295,928	379
13	Mar-17	25000	40,360	3	336,288	382
13	Apr-17	200	14,124	200	14,124	200
13	Apr-17	400	15,375	55	29,499	255
13	Apr-17	800	20,188	36	49,687	291
13	Apr-17	1000	7,341	8	57,028	299
13	Apr-17	2000	57,089	41	114,117	340
13	Apr-17	3000	41,929	17	156,046	357
13	Apr-17	4000	44,936	13	200,982	370
13	Apr-17	5000	22,109	5	223,091	375
13	Apr-17	10000	29,091	5	252,182	380
13	Apr-17	25000	37,880	3	290,062	383
13	May-17	200	13,697	194	13,697	194
13	May-17	400	18,838	66	32,535	260
13	May-17	800	15,385	28	47,920	288
13	May-17	1000	6,409	7	54,329	295
13	May-17	2000	55,035	39	109,364	334
13	May-17	3000	53,708	22	163,072	356
13	May-17	4000	31,152	9	194,224	365
13	May-17	5000	40,091	9	234,315	374
13	May-17	10000	33,112	5	267,427	379
13	May-17	25000	46,480	3	313,907	382
13	Jun-17	200	14,296	199	14,296	199
13	Jun-17	400	17,697	60	31,993	259
13	Jun-17	800	19,005	33	50,998	292
13	Jun-17	1000	11,184	12	62,182	304
13	Jun-17	2000	49,803	34	111,985	338
13	Jun-17	3000	47,716	20	159,701	358

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
13	Jun-17	4000	30,104	9	189,805	367
13	Jun-17	5000	22,747	5	212,552	372
13	Jun-17	10000	46,346	7	258,898	379
13	Jun-17	25000	44,852	3	303,750	382
13	Jul-17	200	14,467	206	14,467	206
13	Jul-17	400	18,080	63	32,547	269
13	Jul-17	800	17,444	30	49,991	299
13	Jul-17	1000	12,773	14	62,764	313
13	Jul-17	2000	55,321	37	118,085	350
13	Jul-17	3000	40,425	17	158,510	367
13	Jul-17	4000	19,941	6	178,451	373
13	Jul-17	5000	8,977	2	187,428	375
13	Jul-17	10000	36,659	6	224,087	381
13	Jul-17	25000	57,613	4	281,700	385
13	Aug-17	200	15,067	205	15,067	205
13	Aug-17	400	16,398	57	31,465	262
13	Aug-17	800	20,219	35	51,684	297
13	Aug-17	1000	8,061	9	59,745	306
13	Aug-17	2000	47,856	33	107,601	339
13	Aug-17	3000	55,961	23	163,562	362
13	Aug-17	4000	30,660	9	194,222	371
13	Aug-17	5000	22,196	5	216,418	376
13	Aug-17	10000	19,746	3	236,164	379
13	Aug-17	25000	69,203	5	305,367	384
13	Sep-17	200	14,237	198	14,237	198
13	Sep-17	400	16,797	58	31,034	256
13	Sep-17	800	19,280	32	50,314	288
13	Sep-17	1000	9,709	11	60,023	299
13	Sep-17	2000	56,407	40	116,430	339
13	Sep-17	3000	63,026	26	179,456	365
13	Sep-17	4000	27,107	8	206,563	373
13	Sep-17	5000	20,841	5	227,404	378
13	Sep-17	10000	16,878	3	244,282	381
13	Sep-17	25000	57,364	4	301,646	385
14	Oct-16	200	4,806	1,240	4,806	1,240
14	Oct-16	400	53,251	187	58,057	1,427
14	Oct-16	800	88,088	155	146,145	1,582
14	Oct-16	1000	29,889	34	176,034	1,616
14	Oct-16	2000	106,255	81	282,289	1,697
14	Oct-16	3000	85,657	36	367,946	1,733
14	Oct-16	4000	69,583	20	437,529	1,753
14	Oct-16	5000	49,852	11	487,381	1,764
14	Oct-16	10000	321,436	47	808,817	1,811
14	Oct-16	25000	561,546	35	1,370,363	1,846
14	Oct-16	50000	126,416	4	1,496,779	1,850

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
14	Oct-16	100000	62,960	1	1,559,739	1,851
14	Nov-16	200	38,260	1,258	38,260	1,258
14	Nov-16	400	51,469	181	89,729	1,439
14	Nov-16	800	84,277	154	174,006	1,593
14	Nov-16	1000	30,308	34	204,314	1,627
14	Nov-16	2000	98,862	72	303,176	1,699
14	Nov-16	3000	84,292	35	387,468	1,734
14	Nov-16	4000	86,978	26	474,446	1,760
14	Nov-16	5000	31,514	7	505,960	1,767
14	Nov-16	10000	304,904	42	810,864	1,809
14	Nov-16	25000	411,844	28	1,222,708	1,837
14	Nov-16	50000	88,922	3	1,311,630	1,840
14	Nov-16	100000	64,720	1	1,376,350	1,841
14	Dec-16	200	49,744	1,265	49,744	1,265
14	Dec-16	400	45,662	156	95,406	1,421
14	Dec-16	800	91,460	157	186,866	1,578
14	Dec-16	1000	32,996	37	219,862	1,615
14	Dec-16	2000	128,770	91	348,632	1,706
14	Dec-16	3000	72,161	30	420,793	1,736
14	Dec-16	4000	90,177	26	510,970	1,762
14	Dec-16	5000	71,438	16	582,408	1,778
14	Dec-16	10000	322,691	43	905,099	1,821
14	Dec-16	25000	224,491	17	1,129,590	1,838
14	Dec-16	100000	57,120	1	1,186,710	1,839
14	Jan-17	200	43,523	1,244	43,523	1,244
14	Jan-17	400	49,296	172	92,819	1,416
14	Jan-17	800	91,013	157	183,832	1,573
14	Jan-17	1000	38,717	43	222,549	1,616
14	Jan-17	2000	128,318	95	350,867	1,711
14	Jan-17	3000	74,514	30	425,381	1,741
14	Jan-17	4000	50,592	15	475,973	1,756
14	Jan-17	5000	57,232	13	533,205	1,769
14	Jan-17	10000	336,420	47	869,625	1,816
14	Jan-17	25000	322,400	25	1,192,025	1,841
14	Jan-17	50000	46,480	1	1,238,505	1,842
14	Feb-17	200	47,326	1,299	47,326	1,299
14	Feb-17	400	50,613	177	97,939	1,476
14	Feb-17	800	78,965	139	176,904	1,615
14	Feb-17	1000	32,648	37	209,552	1,652
14	Feb-17	2000	83,384	59	292,936	1,711
14	Feb-17	3000	65,301	26	358,237	1,737
14	Feb-17	4000	54,595	16	412,832	1,753
14	Feb-17	5000	54,378	12	467,210	1,765
14	Feb-17	10000	375,716	51	842,926	1,816
14	Feb-17	25000	238,224	19	1,081,150	1,835

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
14	Feb-17	50000	39,200	1	1,120,350	1,836
14	Mar-17	200	50,009	1,283	50,009	1,283
14	Mar-17	400	51,760	179	101,769	1,462
14	Mar-17	800	83,349	144	185,118	1,606
14	Mar-17	1000	37,474	42	222,592	1,648
14	Mar-17	2000	89,987	65	312,579	1,713
14	Mar-17	3000	67,613	28	380,192	1,741
14	Mar-17	4000	64,645	19	444,837	1,760
14	Mar-17	5000	43,240	10	488,077	1,770
14	Mar-17	10000	310,200	45	798,277	1,815
14	Mar-17	25000	319,298	23	1,117,575	1,838
14	Mar-17	100000	55,520	1	1,173,095	1,839
14	Apr-17	200	49,983	1,282	49,983	1,282
14	Apr-17	400	50,323	174	100,306	1,456
14	Apr-17	800	82,298	145	182,604	1,601
14	Apr-17	1000	34,836	39	217,440	1,640
14	Apr-17	2000	106,837	76	324,277	1,716
14	Apr-17	3000	68,877	28	393,154	1,744
14	Apr-17	4000	51,954	15	445,108	1,759
14	Apr-17	5000	56,369	13	501,477	1,772
14	Apr-17	10000	303,551	40	805,028	1,812
14	Apr-17	25000	345,052	26	1,150,080	1,838
14	Apr-17	50000	113,180	4	1,263,260	1,842
14	May-17	200	46,583	1,212	46,583	1,212
14	May-17	400	54,305	191	100,888	1,403
14	May-17	800	86,259	151	187,147	1,554
14	May-17	1000	40,005	44	227,152	1,598
14	May-17	2000	116,320	84	343,472	1,682
14	May-17	3000	64,776	27	408,248	1,709
14	May-17	4000	72,234	21	480,482	1,730
14	May-17	5000	74,769	17	555,251	1,747
14	May-17	10000	295,665	39	850,916	1,786
14	May-17	25000	833,161	52	1,684,077	1,838
14	May-17	50000	81,141	3	1,765,218	1,841
14	May-17	100000	61,760	1	1,826,978	1,842
14	Jun-17	200	46,086	1,163	46,086	1,163
14	Jun-17	400	46,828	168	92,914	1,331
14	Jun-17	800	91,351	158	184,265	1,489
14	Jun-17	1000	47,708	55	231,973	1,544
14	Jun-17	2000	154,098	110	386,071	1,654
14	Jun-17	3000	101,202	40	487,273	1,694
14	Jun-17	4000	69,029	20	556,302	1,714
14	Jun-17	5000	71,394	16	627,696	1,730
14	Jun-17	10000	288,185	40	915,881	1,770
14	Jun-17	25000	779,363	53	1,695,244	1,823

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
14	Jun-17	50000	472,272	14	2,167,516	1,837
14	Jun-17	100000	69,360	1	2,236,876	1,838
14	Jul-17	200	46,763	1,184	46,763	1,184
14	Jul-17	400	45,718	160	92,481	1,344
14	Jul-17	800	82,671	143	175,152	1,487
14	Jul-17	1000	44,839	51	219,991	1,538
14	Jul-17	2000	151,024	111	371,015	1,649
14	Jul-17	3000	112,498	46	483,513	1,695
14	Jul-17	4000	54,924	16	538,437	1,711
14	Jul-17	5000	49,694	11	588,131	1,722
14	Jul-17	10000	264,190	38	852,321	1,760
14	Jul-17	25000	922,732	52	1,775,053	1,812
14	Jul-17	50000	689,603	21	2,464,656	1,833
14	Jul-17	100000	66,400	1	2,531,056	1,834
14	Aug-17	200	44,046	1,157	44,046	1,157
14	Aug-17	400	47,081	166	91,127	1,323
14	Aug-17	800	83,296	145	174,423	1,468
14	Aug-17	1000	42,221	47	216,644	1,515
14	Aug-17	2000	177,983	126	394,627	1,641
14	Aug-17	3000	107,115	42	501,742	1,683
14	Aug-17	4000	83,669	24	585,411	1,707
14	Aug-17	5000	44,040	10	629,451	1,717
14	Aug-17	10000	294,211	42	923,662	1,759
14	Aug-17	25000	1,017,737	59	1,941,399	1,818
14	Aug-17	50000	498,941	15	2,440,340	1,833
14	Aug-17	100000	77,520	1	2,517,860	1,834
14	Sep-17	200	45,102	1,172	45,102	1,172
14	Sep-17	400	51,604	179	96,706	1,351
14	Sep-17	800	87,911	152	184,617	1,503
14	Sep-17	1000	46,973	53	231,590	1,556
14	Sep-17	2000	147,884	106	379,474	1,662
14	Sep-17	3000	79,550	33	459,024	1,695
14	Sep-17	4000	85,704	24	544,728	1,719
14	Sep-17	5000	39,855	9	584,583	1,728
14	Sep-17	10000	347,822	48	932,405	1,776
14	Sep-17	25000	679,239	48	1,611,644	1,824
14	Sep-17	50000	411,124	12	2,022,768	1,836
14	Sep-17	100000	87,200	1	2,109,968	1,837
16	Oct-16	200	153	11	153	11
16	Oct-16	400	817	3	970	14
16	Oct-16	800	2,846	5	3,816	19
16	Oct-16	1000	950	1	4,766	20
16	Oct-16	2000	11,683	8	16,449	28
16	Oct-16	3000	29,128	11	45,577	39
16	Oct-16	4000	34,251	10	79,828	49

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
16	Oct-16	5000	60,023	14	139,851	63
16	Oct-16	10000	707,861	89	847,712	152
16	Oct-16	25000	1,185,945	97	2,033,657	249
16	Oct-16	50000	39,033	2	2,072,690	251
16	Nov-16	200	13	10	13	10
16	Nov-16	400	953	4	966	14
16	Nov-16	800	3,700	6	4,666	20
16	Nov-16	2000	9,739	8	14,405	28
16	Nov-16	3000	36,906	15	51,311	43
16	Nov-16	4000	50,547	14	101,858	57
16	Nov-16	5000	34,933	8	136,791	65
16	Nov-16	10000	787,062	100	923,853	165
16	Nov-16	25000	1,003,502	86	1,927,355	251
16	Nov-16	50000	32,522	1	1,959,877	252
16	Dec-16	200	193	10	193	10
16	Dec-16	400	595	2	788	12
16	Dec-16	800	2,034	4	2,822	16
16	Dec-16	1000	2,766	3	5,588	19
16	Dec-16	2000	8,977	7	14,565	26
16	Dec-16	3000	32,330	13	46,895	39
16	Dec-16	4000	58,035	16	104,930	55
16	Dec-16	5000	34,611	8	139,541	63
16	Dec-16	10000	637,861	80	777,402	143
16	Dec-16	25000	1,294,464	107	2,071,866	250
16	Dec-16	50000	33,720	1	2,105,586	251
16	Jan-17	200	54	10	54	10
16	Jan-17	400	635	2	689	12
16	Jan-17	800	679	1	1,368	13
16	Jan-17	2000	11,844	9	13,212	22
16	Jan-17	3000	36,021	14	49,233	36
16	Jan-17	4000	50,959	14	100,192	50
16	Jan-17	5000	48,578	11	148,770	61
16	Jan-17	10000	640,718	79	789,488	140
16	Jan-17	25000	1,371,344	110	2,160,832	250
16	Jan-17	50000	36,420	1	2,197,252	251
16	Feb-17	200	73	10	73	10
16	Feb-17	400	530	2	603	12
16	Feb-17	800	540	1	1,143	13
16	Feb-17	2000	14,246	9	15,389	22
16	Feb-17	3000	40,807	17	56,196	39
16	Feb-17	4000	63,510	18	119,706	57
16	Feb-17	5000	40,702	9	160,408	66
16	Feb-17	10000	761,510	96	921,918	162
16	Feb-17	25000	1,015,232	88	1,937,150	250
16	Feb-17	50000	34,440	1	1,971,590	251

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
16	Mar-17	200	95	10	95	10
16	Mar-17	400	502	2	597	12
16	Mar-17	800	1,834	3	2,431	15
16	Mar-17	1000	990	1	3,421	16
16	Mar-17	2000	12,735	8	16,156	24
16	Mar-17	3000	40,274	16	56,430	40
16	Mar-17	4000	47,610	13	104,040	53
16	Mar-17	5000	48,943	11	152,983	64
16	Mar-17	10000	616,323	79	769,306	143
16	Mar-17	25000	1,341,868	110	2,111,174	253
16	Mar-17	50000	38,580	1	2,149,754	254
16	Apr-17	200	271	10	271	10
16	Apr-17	400	220	1	491	11
16	Apr-17	800	654	1	1,145	12
16	Apr-17	2000	14,058	9	15,203	21
16	Apr-17	3000	44,316	18	59,519	39
16	Apr-17	4000	50,246	14	109,765	53
16	Apr-17	5000	52,518	12	162,283	65
16	Apr-17	10000	738,835	95	901,118	160
16	Apr-17	25000	1,092,279	92	1,993,397	252
16	Apr-17	50000	32,160	1	2,025,557	253
16	May-17	200	199	8	199	8
16	May-17	400	428	2	627	10
16	May-17	2000	19,665	13	20,292	23
16	May-17	3000	27,703	11	47,995	34
16	May-17	4000	39,662	11	87,657	45
16	May-17	5000	64,187	14	151,844	59
16	May-17	10000	503,331	66	655,175	125
16	May-17	25000	1,610,110	126	2,265,285	251
16	May-17	50000	36,780	1	2,302,065	252
16	Jun-17	200	170	8	170	8
16	Jun-17	400	419	2	589	10
16	Jun-17	1000	1,775	2	2,364	12
16	Jun-17	2000	16,075	11	18,439	23
16	Jun-17	3000	20,372	8	38,811	31
16	Jun-17	4000	24,391	7	63,202	38
16	Jun-17	5000	49,142	11	112,344	49
16	Jun-17	10000	603,159	79	715,503	128
16	Jun-17	25000	1,604,983	122	2,320,486	250
16	Jun-17	50000	42,540	1	2,363,026	251
16	Jul-17	200	250	8	250	8
16	Jul-17	400	207	1	457	9
16	Jul-17	1000	1,753	2	2,210	11
16	Jul-17	2000	15,759	11	17,969	22
16	Jul-17	3000	20,981	8	38,950	30

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
16	Jul-17	4000	40,746	11	79,696	41
16	Jul-17	5000	65,309	14	145,005	55
16	Jul-17	10000	735,872	92	880,877	147
16	Jul-17	25000	1,252,274	102	2,133,151	249
16	Aug-17	200	290	7	290	7
16	Aug-17	400	215	1	505	8
16	Aug-17	2000	17,091	12	17,596	20
16	Aug-17	3000	18,662	7	36,258	27
16	Aug-17	4000	34,876	10	71,134	37
16	Aug-17	5000	49,925	11	121,059	48
16	Aug-17	10000	658,105	84	779,164	132
16	Aug-17	25000	1,484,713	117	2,263,877	249
16	Sep-17	200	338	6	338	6
16	Sep-17	400	221	1	559	7
16	Sep-17	2000	15,802	12	16,361	19
16	Sep-17	3000	26,347	10	42,708	29
16	Sep-17	4000	36,167	10	78,875	39
16	Sep-17	5000	36,576	8	115,451	47
16	Sep-17	10000	646,857	85	762,308	132
16	Sep-17	25000	1,436,391	116	2,198,699	248
16 A,B&C	Oct-16	200	20,088	143	20,088	143
16 A,B&C	Oct-16	400	260,803	843	280,891	986
16 A,B&C	Oct-16	800	643,944	1,164	924,835	2,150
16 A,B&C	Oct-16	1000	176,838	198	1,101,673	2,348
16 A,B&C	Oct-16	2000	314,684	242	1,416,357	2,590
16 A,B&C	Oct-16	3000	6,715	3	1,423,072	2,593
16 A,B&C	Nov-16	200	20,253	149	20,253	149
16 A,B&C	Nov-16	400	248,407	803	268,660	952
16 A,B&C	Nov-16	800	671,590	1,216	940,250	2,168
16 A,B&C	Nov-16	1000	173,973	194	1,114,223	2,362
16 A,B&C	Nov-16	2000	311,477	240	1,425,700	2,602
16 A,B&C	Nov-16	3000	4,840	2	1,430,540	2,604
16 A,B&C	Dec-16	200	19,769	143	19,769	143
16 A,B&C	Dec-16	400	228,342	725	248,111	868
16 A,B&C	Dec-16	800	698,531	1,254	946,642	2,122
16 A,B&C	Dec-16	1000	206,112	232	1,152,754	2,354
16 A,B&C	Dec-16	2000	360,958	276	1,513,712	2,630
16 A,B&C	Dec-16	3000	19,573	9	1,533,285	2,639
16 A,B&C	Jan-17	200	15,197	116	15,197	116
16 A,B&C	Jan-17	400	199,089	635	214,286	751
16 A,B&C	Jan-17	800	743,973	1,314	958,259	2,065
16 A,B&C	Jan-17	1000	210,913	238	1,169,172	2,303
16 A,B&C	Jan-17	2000	429,413	326	1,598,585	2,629
16 A,B&C	Jan-17	3000	21,787	10	1,620,372	2,639
16 A,B&C	Jan-17	4000	3,030	1	1,623,402	2,640

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
16 A,B&C	Feb-17	200	22,662	168	22,662	168
16 A,B&C	Feb-17	400	265,473	851	288,135	1,019
16 A,B&C	Feb-17	800	655,730	1,188	943,865	2,207
16 A,B&C	Feb-17	1000	178,661	201	1,122,526	2,408
16 A,B&C	Feb-17	2000	295,340	230	1,417,866	2,638
16 A,B&C	Feb-17	3000	8,707	4	1,426,573	2,642
16 A,B&C	Mar-17	200	18,478	138	18,478	138
16 A,B&C	Mar-17	400	223,714	714	242,192	852
16 A,B&C	Mar-17	800	719,027	1,284	961,219	2,136
16 A,B&C	Mar-17	1000	189,062	212	1,150,281	2,348
16 A,B&C	Mar-17	2000	378,982	289	1,529,263	2,637
16 A,B&C	Mar-17	3000	11,496	5	1,540,759	2,642
16 A,B&C	Apr-17	200	21,750	164	21,750	164
16 A,B&C	Apr-17	400	259,564	833	281,314	997
16 A,B&C	Apr-17	800	679,532	1,221	960,846	2,218
16 A,B&C	Apr-17	1000	167,345	187	1,128,191	2,405
16 A,B&C	Apr-17	2000	303,997	236	1,432,188	2,641
16 A,B&C	Apr-17	3000	8,881	4	1,441,069	2,645
16 A,B&C	May-17	200	16,078	126	16,078	126
16 A,B&C	May-17	400	212,413	680	228,491	806
16 A,B&C	May-17	800	730,859	1,298	959,350	2,104
16 A,B&C	May-17	1000	204,849	229	1,164,199	2,333
16 A,B&C	May-17	2000	409,840	311	1,574,039	2,644
16 A,B&C	May-17	3000	17,396	8	1,591,435	2,652
16 A,B&C	May-17	4000	9,852	3	1,601,287	2,655
16 A,B&C	Jun-17	200	15,002	120	15,002	120
16 A,B&C	Jun-17	400	207,841	660	222,843	780
16 A,B&C	Jun-17	800	739,160	1,302	962,003	2,082
16 A,B&C	Jun-17	1000	206,765	233	1,168,768	2,315
16 A,B&C	Jun-17	2000	430,420	327	1,599,188	2,642
16 A,B&C	Jun-17	3000	32,252	15	1,631,440	2,657
16 A,B&C	Jun-17	4000	3,073	1	1,634,513	2,658
16 A,B&C	Jun-17	5000	4,201	1	1,638,714	2,659
16 A,B&C	Jul-17	200	20,494	156	20,494	156
16 A,B&C	Jul-17	400	244,571	786	265,065	942
16 A,B&C	Jul-17	800	697,712	1,251	962,777	2,193
16 A,B&C	Jul-17	1000	174,497	195	1,137,274	2,388
16 A,B&C	Jul-17	2000	345,985	267	1,483,259	2,655
16 A,B&C	Jul-17	3000	10,991	5	1,494,250	2,660
16 A,B&C	Aug-17	200	17,156	138	17,156	138
16 A,B&C	Aug-17	400	218,849	703	236,005	841
16 A,B&C	Aug-17	800	724,409	1,295	960,414	2,136
16 A,B&C	Aug-17	1000	194,146	218	1,154,560	2,354
16 A,B&C	Aug-17	2000	387,944	298	1,542,504	2,652
16 A,B&C	Aug-17	3000	25,938	12	1,568,442	2,664

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
16 A,B&C	Sep-17	200	18,285	145	18,285	145
16 A,B&C	Sep-17	400	240,256	767	258,541	912
16 A,B&C	Sep-17	800	705,777	1,258	964,318	2,170
16 A,B&C	Sep-17	1000	189,888	212	1,154,206	2,382
16 A,B&C	Sep-17	2000	364,581	277	1,518,787	2,659
16 A,B&C	Sep-17	3000	11,219	5	1,530,006	2,664
20	Oct-16	200	0	5	-	5
20	Oct-16	2000	1,480	1	1,480	6
20	Oct-16	5000	4,900	1	6,380	7
20	Oct-16	10000	56,016	7	62,396	14
20	Oct-16	25000	5,053,698	244	5,116,094	258
20	Oct-16	50000	31,260,800	886	36,376,894	1,144
20	Oct-16	100000	40,743,739	569	77,120,633	1,713
20	Oct-16	250000	59,241,117	391	136,361,750	2,104
20	Oct-16	500000	18,522,872	58	154,884,622	2,162
20	Oct-16	Over 500k	1,625,000	3	156,509,622	2,165
20	Nov-16	800	760	1	760	1
20	Nov-16	5000	9,060	2	9,820	3
20	Nov-16	10000	60,031	8	69,851	11
20	Nov-16	25000	8,796,308	438	8,866,159	449
20	Nov-16	50000	28,260,007	819	37,126,166	1,268
20	Nov-16	100000	36,775,834	524	73,902,000	1,792
20	Nov-16	250000	47,440,359	317	121,342,359	2,109
20	Nov-16	500000	13,468,020	43	134,810,379	2,152
20	Nov-16	Over 500k	557,000	1	135,367,379	2,153
20	Dec-16	200	0	5	-	5
20	Dec-16	4000	3,920	1	3,920	6
20	Dec-16	10000	89,400	13	93,320	19
20	Dec-16	25000	8,800,955	433	8,894,275	452
20	Dec-16	50000	27,593,868	790	36,488,143	1,242
20	Dec-16	100000	36,521,320	519	73,009,463	1,761
20	Dec-16	250000	50,791,645	337	123,801,108	2,098
20	Dec-16	500000	16,017,370	50	139,818,478	2,148
20	Dec-16	Over 500k	573,000	1	140,391,478	2,149
20	Jan-17	10000	64,704	11	64,704	11
20	Jan-17	25000	7,679,255	372	7,743,959	383
20	Jan-17	50000	28,223,775	800	35,967,734	1,183
20	Jan-17	100000	37,241,937	528	73,209,671	1,711
20	Jan-17	250000	56,875,610	381	130,085,281	2,092
20	Jan-17	500000	16,847,480	53	146,932,761	2,145
20	Jan-17	Over 500k	3,331,000	5	150,263,761	2,150
20	Feb-17	200	0	2	-	2
20	Feb-17	4000	3,440	1	3,440	3
20	Feb-17	5000	9,000	2	12,440	5
20	Feb-17	10000	82,062	11	94,502	16

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
20	Feb-17	25000	10,941,393	548	11,035,895	564
20	Feb-17	50000	25,429,242	726	36,465,137	1,290
20	Feb-17	100000	35,404,908	508	71,870,045	1,798
20	Feb-17	250000	45,342,514	304	117,212,559	2,102
20	Feb-17	500000	13,322,690	43	130,535,249	2,145
20	Feb-17	Over 500k	1,074,200	2	131,609,449	2,147
20	Mar-17	200	0	3	-	3
20	Mar-17	2000	1,840	1	1,840	4
20	Mar-17	3000	2,080	1	3,920	5
20	Mar-17	5000	8,600	2	12,520	7
20	Mar-17	10000	55,963	9	68,483	16
20	Mar-17	25000	8,600,335	419	8,668,818	435
20	Mar-17	50000	28,047,766	802	36,716,584	1,237
20	Mar-17	100000	36,993,935	526	73,710,519	1,763
20	Mar-17	250000	50,805,881	335	124,516,400	2,098
20	Mar-17	500000	16,527,210	51	141,043,610	2,149
20	Mar-17	Over 500k	595,000	1	141,638,610	2,150
20	Apr-17	200	0	2	-	2
20	Apr-17	5000	13,800	3	13,800	5
20	Apr-17	10000	46,893	7	60,693	12
20	Apr-17	25000	8,951,298	442	9,011,991	454
20	Apr-17	50000	27,960,951	800	36,972,942	1,254
20	Apr-17	100000	36,499,770	525	73,472,712	1,779
20	Apr-17	250000	49,899,192	334	123,371,904	2,113
20	Apr-17	500000	14,037,880	44	137,409,784	2,157
20	Apr-17	Over 500k	522,000	1	137,931,784	2,158
20	May-17	5000	4,880	1	4,880	1
20	May-17	10000	42,284	5	47,164	6
20	May-17	25000	4,496,915	215	4,544,079	221
20	May-17	50000	31,658,014	886	36,202,093	1,107
20	May-17	100000	40,989,970	577	77,192,063	1,684
20	May-17	250000	60,485,915	398	137,677,978	2,082
20	May-17	500000	21,504,987	68	159,182,965	2,150
20	May-17	Over 500k	2,737,840	5	161,920,805	2,155
20	Jun-17	200	0	3	-	3
20	Jun-17	4000	3,260	1	3,260	4
20	Jun-17	10000	52,817	7	56,077	11
20	Jun-17	25000	2,671,250	128	2,727,327	139
20	Jun-17	50000	31,367,024	852	34,094,351	991
20	Jun-17	100000	44,433,210	629	78,527,561	1,620
20	Jun-17	250000	69,344,084	454	147,871,645	2,074
20	Jun-17	500000	28,139,840	88	176,011,485	2,162
20	Jun-17	Over 500k	2,258,480	4	178,269,965	2,166
20	Jul-17	200	0	3	-	3
20	Jul-17	2000	1,840	1	1,840	4

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
20	Jul-17	3000	2,440	1	4,280	5
20	Jul-17	10000	40,120	5	44,400	10
20	Jul-17	25000	2,786,943	135	2,831,343	145
20	Jul-17	50000	32,074,798	877	34,906,141	1,022
20	Jul-17	100000	43,275,200	612	78,181,341	1,634
20	Jul-17	250000	69,156,028	452	147,337,369	2,086
20	Jul-17	500000	23,885,860	76	171,223,229	2,162
20	Jul-17	Over 500k	2,677,960	3	173,901,189	2,165
20	Aug-17	200	0	3	-	3
20	Aug-17	4000	3,360	1	3,360	4
20	Aug-17	10000	31,600	4	34,960	8
20	Aug-17	25000	2,002,765	97	2,037,725	105
20	Aug-17	50000	31,403,286	844	33,441,011	949
20	Aug-17	100000	44,443,790	635	77,884,801	1,584
20	Aug-17	250000	73,687,487	477	151,572,288	2,061
20	Aug-17	500000	32,964,680	101	184,536,968	2,162
20	Aug-17	Over 500k	2,299,400	5	186,836,368	2,167
20	Sep-17	200	0	2	-	2
20	Sep-17	2000	1,760	1	1,760	3
20	Sep-17	10000	58,484	7	60,244	10
20	Sep-17	25000	2,714,443	133	2,774,687	143
20	Sep-17	50000	32,207,916	886	34,982,603	1,029
20	Sep-17	100000	43,121,860	602	78,104,463	1,631
20	Sep-17	250000	67,226,036	441	145,330,499	2,072
20	Sep-17	500000	27,714,300	87	173,044,799	2,159
20	Sep-17	Over 500k	2,352,400	4	175,397,199	2,163
21	Oct-16	10000	70,019	8	70,019	8
21	Oct-16	25000	6,145,915	344	6,215,934	352
21	Oct-16	50000	2,245,259	71	8,461,193	423
21	Oct-16	100000	356,540	5	8,817,733	428
21	Oct-16	250000	437,360	3	9,255,093	431
21	Oct-16	500000	281,600	1	9,536,693	432
21	Nov-16	200	160	1	160	1
21	Nov-16	10000	161,079	18	161,239	19
21	Nov-16	25000	5,921,002	360	6,082,241	379
21	Nov-16	50000	1,516,757	49	7,598,998	428
21	Nov-16	100000	408,651	6	8,007,649	434
21	Nov-16	250000	667,240	4	8,674,889	438
21	Dec-16	10000	134,452	15	134,452	15
21	Dec-16	25000	6,035,785	363	6,170,237	378
21	Dec-16	50000	1,599,369	50	7,769,606	428
21	Dec-16	100000	287,760	4	8,057,366	432
21	Dec-16	250000	631,654	5	8,689,020	437
21	Dec-16	500000	279,000	1	8,968,020	438
21	Jan-17	3000	2,940	1	2,940	1

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
21	Jan-17	10000	98,260	12	101,200	13
21	Jan-17	25000	5,989,498	351	6,090,698	364
21	Jan-17	50000	1,982,790	62	8,073,488	426
21	Jan-17	100000	322,220	5	8,395,708	431
21	Jan-17	250000	695,920	4	9,091,628	435
21	Jan-17	500000	259,600	1	9,351,228	436
21	Feb-17	800	660	1	660	1
21	Feb-17	2000	1,280	1	1,940	2
21	Feb-17	3000	2,708	1	4,648	3
21	Feb-17	10000	172,590	21	177,238	24
21	Feb-17	25000	5,802,658	366	5,979,896	390
21	Feb-17	50000	1,268,780	41	7,248,676	431
21	Feb-17	100000	284,460	4	7,533,136	435
21	Feb-17	250000	679,320	5	8,212,456	440
21	Mar-17	3000	2,820	1	2,820	1
21	Mar-17	5000	4,800	1	7,620	2
21	Mar-17	10000	126,490	16	134,110	18
21	Mar-17	25000	6,189,856	366	6,323,966	384
21	Mar-17	50000	1,515,087	47	7,839,053	431
21	Mar-17	100000	266,680	4	8,105,733	435
21	Mar-17	250000	830,000	5	8,935,733	440
21	Apr-17	4000	7,040	2	7,040	2
21	Apr-17	10000	156,380	19	163,420	21
21	Apr-17	25000	5,946,803	359	6,110,223	380
21	Apr-17	50000	1,480,322	47	7,590,545	427
21	Apr-17	100000	335,680	5	7,926,225	432
21	Apr-17	250000	665,480	4	8,591,705	436
21	May-17	10000	77,280	9	77,280	9
21	May-17	25000	5,883,143	321	5,960,423	330
21	May-17	50000	2,889,055	94	8,849,478	424
21	May-17	100000	322,580	5	9,172,058	429
21	May-17	250000	562,280	4	9,734,338	433
21	May-17	500000	254,000	1	9,988,338	434
21	Jun-17	3000	2,000	1	2,000	1
21	Jun-17	5000	4,050	1	6,050	2
21	Jun-17	10000	16,430	2	22,480	4
21	Jun-17	25000	5,513,627	289	5,536,107	293
21	Jun-17	50000	4,010,731	130	9,546,838	423
21	Jun-17	100000	412,100	6	9,958,938	429
21	Jun-17	250000	820,960	5	10,779,898	434
21	Jul-17	3000	2,160	1	2,160	1
21	Jul-17	10000	64,431	7	66,591	8
21	Jul-17	25000	5,789,714	306	5,856,305	314
21	Jul-17	50000	3,380,807	110	9,237,112	424
21	Jul-17	100000	383,280	5	9,620,392	429

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
21	Jul-17	250000	634,720	4	10,255,112	433
21	Aug-17	10000	46,280	5	46,280	5
21	Aug-17	25000	5,344,512	278	5,390,792	283
21	Aug-17	50000	4,229,893	139	9,620,685	422
21	Aug-17	100000	573,240	8	10,193,925	430
21	Aug-17	250000	698,120	4	10,892,045	434
21	Sep-17	10000	25,230	4	25,230	4
21	Sep-17	25000	5,586,684	304	5,611,914	308
21	Sep-17	50000	3,680,618	114	9,292,532	422
21	Sep-17	100000	635,460	8	9,927,992	430
21	Sep-17	250000	667,520	4	10,595,512	434
22	Oct-16	200	12,436	275	12,436	275
22	Oct-16	400	35,063	115	47,499	390
22	Oct-16	800	140,737	242	188,236	632
22	Oct-16	1000	78,067	87	266,303	719
22	Oct-16	2000	257,818	184	524,121	903
22	Oct-16	3000	211,182	83	735,303	986
22	Oct-16	4000	207,925	61	943,228	1,047
22	Oct-16	5000	170,118	38	1,113,346	1,085
22	Oct-16	10000	521,486	72	1,634,832	1,157
22	Oct-16	25000	2,729,212	158	4,364,044	1,315
22	Oct-16	50000	4,813,980	133	9,178,024	1,448
22	Oct-16	100000	14,708,935	209	23,886,959	1,657
22	Oct-16	250000	10,470,661	71	34,357,620	1,728
22	Oct-16	500000	2,201,555	7	36,559,175	1,735
22	Nov-16	200	13,434	309	13,434	309
22	Nov-16	400	40,145	138	53,579	447
22	Nov-16	800	153,525	265	207,104	712
22	Nov-16	1000	59,401	67	266,505	779
22	Nov-16	2000	228,091	166	494,596	945
22	Nov-16	3000	202,843	82	697,439	1,027
22	Nov-16	4000	144,328	43	841,767	1,070
22	Nov-16	5000	107,122	24	948,889	1,094
22	Nov-16	10000	684,585	94	1,633,474	1,188
22	Nov-16	25000	2,747,297	164	4,380,771	1,352
22	Nov-16	50000	5,830,860	156	10,211,631	1,508
22	Nov-16	100000	11,357,447	170	21,569,078	1,678
22	Nov-16	250000	7,239,400	53	28,808,478	1,731
22	Nov-16	500000	570,678	2	29,379,156	1,733
22	Dec-16	200	14,158	298	14,158	298
22	Dec-16	400	29,872	98	44,030	396
22	Dec-16	800	147,089	248	191,119	644
22	Dec-16	1000	76,208	86	267,327	730
22	Dec-16	2000	243,295	172	510,622	902
22	Dec-16	3000	202,811	84	713,433	986

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
22	Dec-16	4000	181,053	54	894,486	1,040
22	Dec-16	5000	157,673	35	1,052,159	1,075
22	Dec-16	10000	774,806	106	1,826,965	1,181
22	Dec-16	25000	2,642,869	155	4,469,834	1,336
22	Dec-16	50000	7,045,342	183	11,515,176	1,519
22	Dec-16	100000	10,626,080	155	22,141,256	1,674
22	Dec-16	250000	7,953,381	57	30,094,637	1,731
22	Dec-16	500000	799,514	3	30,894,151	1,734
22	Jan-17	200	12,798	299	12,798	299
22	Jan-17	400	29,581	100	42,379	399
22	Jan-17	800	128,138	214	170,517	613
22	Jan-17	1000	74,700	84	245,217	697
22	Jan-17	2000	258,806	186	504,023	883
22	Jan-17	3000	223,469	90	727,492	973
22	Jan-17	4000	177,940	52	905,432	1,025
22	Jan-17	5000	169,422	38	1,074,854	1,063
22	Jan-17	10000	791,493	110	1,866,347	1,173
22	Jan-17	25000	2,577,134	152	4,443,481	1,325
22	Jan-17	50000	6,203,460	166	10,646,941	1,491
22	Jan-17	100000	12,663,495	185	23,310,436	1,676
22	Jan-17	250000	8,896,112	59	32,206,548	1,735
22	Jan-17	500000	308,400	1	32,514,948	1,736
22	Feb-17	200	12,748	299	12,748	299
22	Feb-17	400	31,080	101	43,828	400
22	Feb-17	800	146,861	253	190,689	653
22	Feb-17	1000	73,039	80	263,728	733
22	Feb-17	2000	254,398	180	518,126	913
22	Feb-17	3000	185,362	79	703,488	992
22	Feb-17	4000	194,181	55	897,669	1,047
22	Feb-17	5000	189,034	42	1,086,703	1,089
22	Feb-17	10000	624,371	87	1,711,074	1,176
22	Feb-17	25000	2,697,731	161	4,408,805	1,337
22	Feb-17	50000	6,269,734	169	10,678,539	1,506
22	Feb-17	100000	12,040,358	179	22,718,897	1,685
22	Feb-17	250000	7,405,478	53	30,124,375	1,738
22	Feb-17	500000	549,208	2	30,673,583	1,740
22	Mar-17	200	13,269	287	13,269	287
22	Mar-17	400	26,703	88	39,972	375
22	Mar-17	800	141,943	236	181,915	611
22	Mar-17	1000	82,493	93	264,408	704
22	Mar-17	2000	273,442	197	537,850	901
22	Mar-17	3000	194,415	80	732,265	981
22	Mar-17	4000	177,845	51	910,110	1,032
22	Mar-17	5000	178,270	40	1,088,380	1,072
22	Mar-17	10000	629,893	89	1,718,273	1,161

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
22	Mar-17	25000	2,849,952	170	4,568,225	1,331
22	Mar-17	50000	5,736,743	155	10,304,968	1,486
22	Mar-17	100000	12,766,693	189	23,071,661	1,675
22	Mar-17	250000	8,257,275	58	31,328,936	1,733
22	Mar-17	500000	552,300	2	31,881,236	1,735
22	Apr-17	200	13,604	302	13,604	302
22	Apr-17	400	42,709	140	56,313	442
22	Apr-17	800	153,904	264	210,217	706
22	Apr-17	1000	64,251	73	274,468	779
22	Apr-17	2000	224,421	161	498,889	940
22	Apr-17	3000	202,848	83	701,737	1,023
22	Apr-17	4000	138,987	41	840,724	1,064
22	Apr-17	5000	144,679	32	985,403	1,096
22	Apr-17	10000	600,739	82	1,586,142	1,178
22	Apr-17	25000	2,910,514	174	4,496,656	1,352
22	Apr-17	50000	6,092,862	163	10,589,518	1,515
22	Apr-17	100000	11,290,000	169	21,879,518	1,684
22	Apr-17	250000	6,576,291	47	28,455,809	1,731
22	Apr-17	500000	285,000	1	28,740,809	1,732
22	May-17	200	12,952	297	12,952	297
22	May-17	400	31,494	108	44,446	405
22	May-17	800	126,171	219	170,617	624
22	May-17	1000	72,464	82	243,081	706
22	May-17	2000	304,819	223	547,900	929
22	May-17	3000	178,513	67	726,413	996
22	May-17	4000	164,217	47	890,630	1,043
22	May-17	5000	157,460	35	1,048,090	1,078
22	May-17	10000	596,343	81	1,644,433	1,159
22	May-17	25000	2,485,622	148	4,130,055	1,307
22	May-17	50000	5,313,932	145	9,443,987	1,452
22	May-17	100000	14,328,404	202	23,772,391	1,654
22	May-17	250000	11,124,083	76	34,896,474	1,730
22	May-17	500000	945,900	3	35,842,374	1,733
22	Jun-17	200	13,198	294	13,198	294
22	Jun-17	400	29,834	101	43,032	395
22	Jun-17	800	117,135	199	160,167	594
22	Jun-17	1000	66,461	74	226,628	668
22	Jun-17	2000	291,102	207	517,730	875
22	Jun-17	3000	202,443	82	720,173	957
22	Jun-17	4000	169,737	49	889,910	1,006
22	Jun-17	5000	150,119	34	1,040,029	1,040
22	Jun-17	10000	571,978	80	1,612,007	1,120
22	Jun-17	25000	2,664,333	155	4,276,340	1,275
22	Jun-17	50000	5,608,357	149	9,884,697	1,424
22	Jun-17	100000	13,777,524	192	23,662,221	1,616

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
22	Jun-17	250000	12,043,122	82	35,705,343	1,698
22	Jun-17	500000	1,895,097	6	37,600,440	1,704
22	Jul-17	200	11,700	301	11,700	301
22	Jul-17	400	30,290	101	41,990	402
22	Jul-17	800	110,142	183	152,132	585
22	Jul-17	1000	73,723	83	225,855	668
22	Jul-17	2000	272,762	193	498,617	861
22	Jul-17	3000	176,807	73	675,424	934
22	Jul-17	4000	203,933	59	879,357	993
22	Jul-17	5000	166,542	37	1,045,899	1,030
22	Jul-17	10000	687,718	93	1,733,617	1,123
22	Jul-17	25000	2,632,356	155	4,365,973	1,278
22	Jul-17	50000	6,210,821	167	10,576,794	1,445
22	Jul-17	100000	12,109,102	176	22,685,896	1,621
22	Jul-17	250000	10,089,902	69	32,775,798	1,690
22	Jul-17	500000	1,511,332	5	34,287,130	1,695
22	Aug-17	200	9,186	278	9,186	278
22	Aug-17	400	20,668	72	29,854	350
22	Aug-17	800	103,867	177	133,721	527
22	Aug-17	1000	59,930	67	193,651	594
22	Aug-17	2000	332,385	234	526,036	828
22	Aug-17	3000	236,540	97	762,576	925
22	Aug-17	4000	173,270	50	935,846	975
22	Aug-17	5000	188,089	42	1,123,935	1,017
22	Aug-17	10000	677,747	96	1,801,682	1,113
22	Aug-17	25000	2,594,126	150	4,395,808	1,263
22	Aug-17	50000	5,672,932	153	10,068,740	1,416
22	Aug-17	100000	14,520,812	200	24,589,552	1,616
22	Aug-17	250000	12,932,743	88	37,522,295	1,704
22	Aug-17	500000	3,024,632	10	40,546,927	1,714
22	Sep-17	200	10,074	279	10,074	279
22	Sep-17	400	24,995	83	35,069	362
22	Sep-17	800	94,148	156	129,217	518
22	Sep-17	1000	68,861	77	198,078	595
22	Sep-17	2000	348,355	248	546,433	843
22	Sep-17	3000	209,795	87	756,228	930
22	Sep-17	4000	182,847	52	939,075	982
22	Sep-17	5000	173,212	38	1,112,287	1,020
22	Sep-17	10000	581,372	85	1,693,659	1,105
22	Sep-17	25000	2,549,605	149	4,243,264	1,254
22	Sep-17	50000	5,057,998	138	9,301,262	1,392
22	Sep-17	100000	15,032,241	205	24,333,503	1,597
22	Sep-17	250000	14,752,912	104	39,086,415	1,701
22	Sep-17	500000	3,914,992	13	43,001,407	1,714
23	Oct-16	250000	603,992	3	603,992	3

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
23	Oct-16	500000	9,076,021	23	9,680,013	26
23	Oct-16	Over 500k	251,420,917	78	261,100,930	104
23	Nov-16	250000	760,454	4	760,454	4
23	Nov-16	500000	9,460,742	25	10,221,196	29
23	Nov-16	Over 500k	251,493,114	76	261,714,310	105
23	Dec-16	100000	81,008	1	81,008	1
23	Dec-16	250000	539,355	3	620,363	4
23	Dec-16	500000	8,851,518	24	9,471,881	28
23	Dec-16	Over 500k	258,439,671	78	267,911,552	106
23	Jan-17	200	0	1	-	1
23	Jan-17	5000	4,190	1	4,190	2
23	Jan-17	50000	45,079	1	49,269	3
23	Jan-17	250000	770,766	4	820,035	7
23	Jan-17	500000	9,641,287	25	10,461,322	32
23	Jan-17	Over 500k	258,282,895	75	268,744,217	107
23	Feb-17	100000	58,190	1	58,190	1
23	Feb-17	250000	929,536	5	987,726	6
23	Feb-17	500000	9,262,619	24	10,250,345	30
23	Feb-17	Over 500k	238,753,100	77	249,003,445	107
23	Mar-17	250000	768,266	4	768,266	4
23	Mar-17	500000	8,582,756	21	9,351,022	25
23	Mar-17	Over 500k	265,858,604	80	275,209,626	105
23	Apr-17	250000	559,407	3	559,407	3
23	Apr-17	500000	8,550,969	23	9,110,376	26
23	Apr-17	Over 500k	260,089,378	80	269,199,754	106
23	May-17	250000	597,311	3	597,311	3
23	May-17	500000	5,639,337	15	6,236,648	18
23	May-17	Over 500k	289,662,249	89	295,898,897	107
23	Jun-17	250000	410,232	2	410,232	2
23	Jun-17	500000	6,193,827	15	6,604,059	17
23	Jun-17	Over 500k	290,869,289	89	297,473,348	106
23	Jul-17	250000	629,695	3	629,695	3
23	Jul-17	500000	7,411,227	19	8,040,922	22
23	Jul-17	Over 500k	284,067,423	86	292,108,345	108
23	Aug-17	250000	700,103	3	700,103	3
23	Aug-17	500000	6,607,177	16	7,307,280	19
23	Aug-17	Over 500k	297,578,121	91	304,885,401	110
23	Sep-17	250000	404,190	2	404,190	2
23	Sep-17	500000	7,922,302	21	8,326,492	23
23	Sep-17	Over 500k	280,550,899	87	288,877,391	110
24	Oct-16	50000	70,183	2	70,183	2
24	Oct-16	250000	3,432,594	18	3,502,777	20
24	Oct-16	500000	28,042,041	73	31,544,818	93
24	Oct-16	Over 500k	132,728,146	86	164,272,964	179
24	Nov-16	100000	200,896	3	200,896	3

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
24	Nov-16	250000	4,338,189	24	4,539,085	27
24	Nov-16	500000	28,480,881	78	33,019,966	105
24	Nov-16	Over 500k	115,979,537	74	148,999,503	179
24	Dec-16	250000	3,735,022	21	3,735,022	21
24	Dec-16	500000	30,652,163	82	34,387,185	103
24	Dec-16	Over 500k	117,677,499	76	152,064,684	179
24	Jan-17	25000	15,040	1	15,040	1
24	Jan-17	250000	3,609,375	20	3,624,415	21
24	Jan-17	500000	26,746,606	72	30,371,021	93
24	Jan-17	Over 500k	130,600,362	86	160,971,383	179
24	Feb-17	50000	45,832	1	45,832	1
24	Feb-17	250000	4,094,099	24	4,139,931	25
24	Feb-17	500000	28,957,946	80	33,097,877	105
24	Feb-17	Over 500k	107,432,439	73	140,530,316	178
24	Mar-17	25000	23,876	1	23,876	1
24	Mar-17	50000	42,180	1	66,056	2
24	Mar-17	100000	64,578	1	130,634	3
24	Mar-17	250000	3,949,304	21	4,079,938	24
24	Mar-17	500000	26,552,243	72	30,632,181	96
24	Mar-17	Over 500k	120,117,307	83	150,749,488	179
24	Apr-17	50000	58,942	2	58,942	2
24	Apr-17	250000	4,318,061	23	4,377,003	25
24	Apr-17	500000	29,240,722	79	33,617,725	104
24	Apr-17	Over 500k	115,651,321	74	149,269,046	178
24	May-17	10000	8,487	1	8,487	1
24	May-17	25000	17,868	1	26,355	2
24	May-17	250000	2,137,596	11	2,163,951	13
24	May-17	500000	24,877,971	66	27,041,922	79
24	May-17	Over 500k	146,583,853	97	173,625,775	176
24	Jun-17	25000	36,654	2	36,654	2
24	Jun-17	250000	2,611,417	13	2,648,071	15
24	Jun-17	500000	20,269,078	52	22,917,149	67
24	Jun-17	Over 500k	161,627,292	109	184,544,441	176
24	Jul-17	100000	130,199	2	130,199	2
24	Jul-17	250000	2,765,231	14	2,895,430	16
24	Jul-17	500000	22,835,807	59	25,731,237	75
24	Jul-17	Over 500k	160,956,131	102	186,687,368	177
24	Aug-17	100000	172,269	2	172,269	2
24	Aug-17	250000	2,411,663	12	2,583,932	14
24	Aug-17	500000	20,398,660	53	22,982,592	67
24	Aug-17	Over 500k	168,918,559	109	191,901,151	176
24	Sep-17	100000	175,467	2	175,467	2
24	Sep-17	250000	2,566,590	13	2,742,057	15
24	Sep-17	500000	22,929,406	59	25,671,463	74
24	Sep-17	Over 500k	155,419,155	102	181,090,618	176

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
28	Oct-16	5000	14,179	3	14,179	3
28	Oct-16	10000	52,945	7	67,124	10
28	Oct-16	25000	109,772	9	176,896	19
28	Nov-16	5000	4,451	1	4,451	1
28	Nov-16	10000	93,235	12	97,686	13
28	Nov-16	25000	85,147	7	182,833	20
28	Dec-16	5000	4,574	1	4,574	1
28	Dec-16	10000	79,621	10	84,195	11
28	Dec-16	25000	110,488	9	194,683	20
28	Jan-17	10000	75,805	10	75,805	10
28	Jan-17	25000	121,506	10	197,311	20
28	Feb-17	5000	4,385	1	4,385	1
28	Feb-17	10000	72,087	10	76,472	11
28	Feb-17	25000	104,013	10	180,485	21
28	Mar-17	5000	4,732	1	4,732	1
28	Mar-17	10000	80,009	10	84,741	11
28	Mar-17	25000	109,257	9	193,998	20
28	Apr-17	10000	91,325	12	91,325	12
28	Apr-17	25000	95,342	8	186,667	20
28	May-17	10000	79,711	10	79,711	10
28	May-17	25000	130,978	10	210,689	20
28	Jun-17	10000	72,095	9	72,095	9
28	Jun-17	25000	145,383	11	217,478	20
28	Jul-17	10000	86,832	11	86,832	11
28	Jul-17	25000	110,639	9	197,471	20
28	Aug-17	10000	80,998	10	80,998	10
28	Aug-17	25000	129,145	10	210,143	20
28	Sep-17	10000	70,978	9	70,978	9
28	Sep-17	25000	135,949	11	206,927	20
29	Oct-16	200	9,395	219	9,395	219
29	Oct-16	400	25,814	79	35,209	298
29	Oct-16	800	92,871	158	128,080	456
29	Oct-16	1000	68,692	77	196,772	533
29	Oct-16	2000	48,045	43	244,817	576
29	Oct-16	3000	12,271	5	257,088	581
29	Oct-16	4000	3,096	1	260,184	582
29	Oct-16	5000	13,779	3	273,963	585
29	Oct-16	10000	35,661	5	309,624	590
29	Oct-16	25000	14,639	1	324,263	591
29	Oct-16	50000	40,466	1	364,729	592
29	Nov-16	200	4,655	219	4,655	219
29	Nov-16	400	25,814	79	30,469	298
29	Nov-16	800	93,717	159	124,186	457
29	Nov-16	1000	68,692	77	192,878	534
29	Nov-16	2000	46,581	42	239,459	576

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
29	Nov-16	3000	12,271	5	251,730	581
29	Nov-16	4000	3,096	1	254,826	582
29	Nov-16	5000	8,370	2	263,196	584
29	Nov-16	10000	44,865	6	308,061	590
29	Nov-16	25000	14,639	1	322,700	591
29	Nov-16	50000	40,466	1	363,166	592
29	Dec-16	200	9,257	218	9,257	218
29	Dec-16	400	24,716	76	33,973	294
29	Dec-16	800	88,730	150	122,703	444
29	Dec-16	1000	62,463	70	185,166	514
29	Dec-16	2000	44,829	40	229,995	554
29	Dec-16	3000	12,271	5	242,266	559
29	Dec-16	4000	3,096	1	245,362	560
29	Dec-16	5000	12,972	3	258,334	563
29	Dec-16	10000	35,661	5	293,995	568
29	Dec-16	25000	14,639	1	308,634	569
29	Dec-16	50000	40,466	1	349,100	570
29	Jan-17	200	9,538	230	9,538	230
29	Jan-17	400	24,721	76	34,259	306
29	Jan-17	800	90,416	153	124,675	459
29	Jan-17	1000	64,119	72	188,794	531
29	Jan-17	2000	44,766	40	233,560	571
29	Jan-17	3000	12,271	5	245,831	576
29	Jan-17	4000	3,096	1	248,927	577
29	Jan-17	5000	12,972	3	261,899	580
29	Jan-17	10000	35,661	5	297,560	585
29	Jan-17	25000	14,639	1	312,199	586
29	Jan-17	50000	40,466	1	352,665	587
29	Feb-17	200	10,895	261	10,895	261
29	Feb-17	400	27,259	87	38,154	348
29	Feb-17	800	80,878	137	119,032	485
29	Feb-17	1000	63,459	71	182,491	556
29	Feb-17	2000	44,766	40	227,257	596
29	Feb-17	3000	12,271	5	239,528	601
29	Feb-17	4000	3,096	1	242,624	602
29	Feb-17	5000	12,972	3	255,596	605
29	Feb-17	10000	44,305	6	299,901	611
29	Feb-17	25000	14,639	1	314,540	612
29	Feb-17	50000	40,466	1	355,006	613
29	Mar-17	200	9,838	260	9,838	260
29	Mar-17	400	22,628	70	32,466	330
29	Mar-17	800	81,137	137	113,603	467
29	Mar-17	1000	63,417	71	177,020	538
29	Mar-17	2000	46,098	41	223,118	579
29	Mar-17	3000	13,007	5	236,125	584

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
29	Mar-17	4000	3,096	1	239,221	585
29	Mar-17	5000	17,824	4	257,045	589
29	Mar-17	10000	40,701	6	297,746	595
29	Mar-17	25000	14,639	1	312,385	596
29	Mar-17	50000	39,458	1	351,843	597
29	Apr-17	200	9,792	260	9,792	260
29	Apr-17	400	23,600	73	33,392	333
29	Apr-17	800	82,681	141	116,073	474
29	Apr-17	1000	62,463	70	178,536	544
29	Apr-17	2000	45,906	41	224,442	585
29	Apr-17	3000	13,007	5	237,449	590
29	Apr-17	4000	6,646	2	244,095	592
29	Apr-17	5000	12,972	3	257,067	595
29	Apr-17	10000	40,701	6	297,768	601
29	Apr-17	25000	14,639	1	312,407	602
29	Apr-17	50000	39,458	1	351,865	603
29	May-17	200	10,032	262	10,032	262
29	May-17	400	23,294	72	33,326	334
29	May-17	800	83,589	141	116,915	475
29	May-17	1000	62,463	70	179,378	545
29	May-17	2000	47,427	42	226,805	587
29	May-17	3000	17,255	7	244,060	594
29	May-17	4000	9,988	3	254,048	597
29	May-17	5000	12,972	3	267,020	600
29	May-17	10000	45,926	7	312,946	607
29	May-17	25000	14,639	1	327,585	608
29	May-17	50000	39,458	1	367,043	609
29	Jun-17	200	10,022	270	10,022	270
29	Jun-17	400	23,779	74	33,801	344
29	Jun-17	800	83,396	141	117,197	485
29	Jun-17	1000	64,244	71	181,441	556
29	Jun-17	2000	54,230	48	235,671	604
29	Jun-17	3000	15,357	6	251,028	610
29	Jun-17	4000	9,976	3	261,004	613
29	Jun-17	5000	12,972	3	273,976	616
29	Jun-17	10000	45,926	7	319,902	623
29	Jun-17	25000	14,639	1	334,541	624
29	Jun-17	50000	39,458	1	373,999	625
29	Jul-17	200	9,277	269	9,277	269
29	Jul-17	400	23,779	75	33,056	344
29	Jul-17	800	83,951	142	117,007	486
29	Jul-17	1000	62,463	70	179,470	556
29	Jul-17	2000	57,601	51	237,071	607
29	Jul-17	3000	17,671	7	254,742	614
29	Jul-17	4000	6,426	2	261,168	616

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
29	Jul-17	5000	12,972	3	274,140	619
29	Jul-17	10000	45,907	7	320,047	626
29	Jul-17	25000	14,639	1	334,686	627
29	Jul-17	50000	39,458	1	374,144	628
29	Aug-17	200	9,723	273	9,723	273
29	Aug-17	400	24,073	75	33,796	348
29	Aug-17	800	83,989	143	117,785	491
29	Aug-17	1000	65,018	73	182,803	564
29	Aug-17	2000	58,641	50	241,444	614
29	Aug-17	3000	17,671	7	259,115	621
29	Aug-17	4000	6,426	2	265,541	623
29	Aug-17	5000	13,370	3	278,911	626
29	Aug-17	10000	46,048	7	324,959	633
29	Aug-17	25000	14,639	1	339,598	634
29	Aug-17	50000	38,749	1	378,347	635
29	Sep-17	200	10,424	275	10,424	275
29	Sep-17	400	24,255	76	34,679	351
29	Sep-17	800	86,084	146	120,763	497
29	Sep-17	1000	64,182	72	184,945	569
29	Sep-17	2000	62,300	53	247,245	622
29	Sep-17	3000	17,671	7	264,916	629
29	Sep-17	4000	6,426	2	271,342	631
29	Sep-17	5000	13,007	3	284,349	634
29	Sep-17	10000	46,024	7	330,373	641
29	Sep-17	25000	14,639	1	345,012	642
29	Sep-17	50000	38,749	1	383,761	643
21A	Oct-16	25000	17,760	2	17,760	2
21A	Oct-16	50000	27,800	1	45,560	3
21A	Oct-16	100000	509,300	6	554,860	9
21A	Oct-16	250000	16,295,930	96	16,850,790	105
21A	Oct-16	500000	3,442,800	12	20,293,590	117
21A	Nov-16	25000	43,840	2	43,840	2
21A	Nov-16	100000	829,140	10	872,980	12
21A	Nov-16	250000	15,818,660	100	16,691,640	112
21A	Nov-16	500000	1,153,200	4	17,844,840	116
21A	Dec-16	25000	46,080	2	46,080	2
21A	Dec-16	100000	378,760	6	424,840	8
21A	Dec-16	250000	16,508,680	102	16,933,520	110
21A	Dec-16	500000	1,744,160	6	18,677,680	116
21A	Jan-17	25000	24,480	1	24,480	1
21A	Jan-17	50000	26,400	1	50,880	2
21A	Jan-17	100000	376,400	5	427,280	7
21A	Jan-17	250000	15,764,880	97	16,192,160	104
21A	Jan-17	500000	3,498,320	12	19,690,480	116
21A	Feb-17	25000	41,360	2	41,360	2

RATE	MONTH	BREAK	Monthly KWH	Monthly Customer	Cumulative Monthly KWH	Cumulative Monthly Customer
21A	Feb-17	100000	778,820	10	820,180	12
21A	Feb-17	250000	15,488,840	101	16,309,020	113
21A	Feb-17	500000	861,680	3	17,170,700	116
21A	Mar-17	25000	43,680	2	43,680	2
21A	Mar-17	50000	25,600	1	69,280	3
21A	Mar-17	100000	519,800	7	589,080	10
21A	Mar-17	250000	15,961,620	99	16,550,700	109
21A	Mar-17	500000	1,979,680	7	18,530,380	116
21A	Apr-17	25000	15,360	1	15,360	1
21A	Apr-17	50000	28,600	1	43,960	2
21A	Apr-17	100000	1,173,020	14	1,216,980	16
21A	Apr-17	250000	15,095,070	94	16,312,050	110
21A	Apr-17	500000	1,553,120	5	17,865,170	115
21A	May-17	25000	15,040	1	15,040	1
21A	May-17	50000	30,800	1	45,840	2
21A	May-17	100000	317,920	4	363,760	6
21A	May-17	250000	15,805,630	93	16,169,390	99
21A	May-17	500000	4,413,780	15	20,583,170	114
21A	Jun-17	25000	13,440	1	13,440	1
21A	Jun-17	50000	38,200	1	51,640	2
21A	Jun-17	100000	367,920	4	419,560	6
21A	Jun-17	250000	14,505,480	83	14,925,040	89
21A	Jun-17	500000	7,517,800	25	22,442,840	114
21A	Jul-17	25000	13,280	1	13,280	1
21A	Jul-17	50000	38,240	1	51,520	2
21A	Jul-17	100000	454,640	5	506,160	7
21A	Jul-17	250000	14,990,200	86	15,496,360	93
21A	Jul-17	500000	5,984,640	20	21,481,000	113
21A	Aug-17	25000	12,800	1	12,800	1
21A	Aug-17	50000	39,680	1	52,480	2
21A	Aug-17	100000	273,320	3	325,800	5
21A	Aug-17	250000	14,802,510	83	15,128,310	88
21A	Aug-17	500000	7,625,280	25	22,753,590	113
21A	Sep-17	25000	13,120	1	13,120	1
21A	Sep-17	50000	39,120	1	52,240	2
21A	Sep-17	100000	259,520	3	311,760	5
21A	Sep-17	250000	15,185,450	89	15,497,210	94
21A	Sep-17	500000	6,532,280	20	22,029,490	114

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Office of Regulatory Staff's
First Continuing Audit Request
Docket No. 2017-370-E

Response No. 1-15

The billing determinants for each rate schedule for the test year are as follows:

RESIDENTIAL

Rate 1		
# of bills		257,018
1st 800 kwh	All	181,267,112
Over 800 kwh	Summer	61,302,745
	Non-Summer	65,301,623
Rate 2		
# of bills		184,517
All kwh	All	23,133,328
Rate 5		
# of bills		850
On-Peak kwh	Summer	68,772
	Non-Summer	71,874
Off-Peak kwh	All	850,338
Rate 6		
# of bills		377,438
1st 800 kwh	All	262,408,722
Over 800 kwh	Summer	88,715,453
	Non-Summer	91,541,735
Rate 7		
# of bills		121
On-Peak KW	Summer	292
	Non-Summer	618
On-Peak kwh		31,126
Off-Peak kwh		234,480
Rate 8		
# of bills		6,534,257
1st 800 kwh	All	4,289,623,310
Over 800 kwh	Summer	1,244,331,989
	Non-Summer	1,216,930,173

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

Answer No. 1-18 (a)

		TEST YEAR	
RATE	**Oct-16 CUSTOMERS**	**AVERAGE CUSTOMERS**	**Sept-17 CUSTOMERS**
RESIDENTIAL			
Rate 1 - Good Cents	21,394	21,418	21,405
Rate 2 - Low Use	15,046	15,376	16,336
Rate 5 - Time-of-Use (KWH Only)	69	71	70
Rate 6 - Energy Saver / Conservation	31,347	31,453	31,490
Rate 7 - Time-of-Use Demand	9	10	11
Rate 8 - Residential	539,255	544,521	546,874
Total Residential Class	**607,120**	**612,849**	**616,186**
SMALL GENERAL SERVICE			
Rate 3 - Municipal Power	3,391	3,423	3,475
Rate 9 - Small General	79,473	79,881	80,262
Rate 29 - Small General (Unmetered)	592	608	643
Rate 10 - Small Construction	2,147	2,318	2,328
Rate 11 - Irrigation	320	320	321
Rate 12 - Church	3,697	3,689	3,678
Rate 13 - Municipal Lighting	383	383	385
Rate 14 - Farm	1,851	1,841	1,837
Rate 16 - Time-of-Use	2,845	2,893	2,912
Rate 22 - School	1,735	1,726	1,716
Rate 28 - SGS TOU Demand	19	20	20
Total Small General Service Class	**96,453**	**97,102**	**97,577**
MEDIUM GENERAL SERVICE			
Rate 20 - Medium General	2,163	2,158	2,164
Rate 21 - Time-of-Use	432	436	433
Rate 21A - Experimental Time-of-Use	117	115	114
Total Medium General Service Class	**2,712**	**2,709**	**2,711**
LARGE GENERAL SERVICE			
Rate 23 - Industrial Power	104	107	110
Rate 24 - Time-of-Use	179	178	176
Contracts	32	31	29
Total Large General Service Class	**315**	**316**	**315**
LIGHTING			
Rate 17	209	209	209
Rate 18	3,051	3,064	3,087
Rate 25	12,935	13,024	13,098
Rate 26	69,193	69,211	69,216
Shared and Subdivision Lighting	150,121	150,753	151,036
Contracts	272	266	266
Total Lighting Class	**235,781**	**236,527**	**236,912**
RETAIL TOTAL	**942,381**	**949,503**	**953,701**

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Office of Regulatory Staff
Audit Information Request
Docket No. 2017-370-E

Response 1-19:

BILL COMPARISON
RESIDENTIAL SERVICE
RATE 8

SERVICE	KWH	CURRENT RATE	PROPOSED RATE	INCREASE AMOUNT	%
General - Summer	Min.	$ 10.91	$ 10.91	$ -	0.00%
Schedule - Res	100	$ 24.55	$ 24.04	$ (0.51)	-2.08%
	250	$ 45.02	$ 43.73	$ (1.29)	-2.87%
	500	$ 79.13	$ 76.56	$ (2.57)	-3.25%
	750	$ 113.24	$ 109.38	$ (3.86)	-3.41%
	1,000	$ 150.09	$ 144.83	$ (5.26)	-3.50%
	2,000	$ 300.23	$ 289.25	$ (10.98)	-3.66%
	3,000	$ 450.37	$ 433.67	$ (16.70)	-3.71%
	4,000	$ 600.51	$ 578.09	$ (22.42)	-3.73%
	5,000	$ 750.65	$ 722.51	$ (28.14)	-3.75%
	6,000	$ 900.79	$ 866.93	$ (33.86)	-3.76%
	BFC	$ 10.91	$ 10.91	$ -	0.00%
	1st 800 KWH	$ 0.13644	$ 0.13129	$ (0.00515)	-3.77%
	Over 800 KWH	$ 0.15014	$ 0.14442	$ (0.00572)	-3.81%

SERVICE	KWH	CURRENT RATE	PROPOSED RATE	INCREASE AMOUNT	%
General - Winter	Min.	$ 10.91	$ 10.91	$ -	0.00%
Schedule - Res	100	$ 24.55	$ 24.04	$ (0.51)	-2.08%
	250	$ 45.02	$ 43.73	$ (1.29)	-2.87%
	500	$ 79.13	$ 76.56	$ (2.57)	-3.25%
	750	$ 113.24	$ 109.38	$ (3.86)	-3.41%
	1,000	$ 146.25	$ 141.15	$ (5.10)	-3.49%
	2,000	$ 277.21	$ 267.19	$ (10.02)	-3.61%
	3,000	$ 408.17	$ 393.23	$ (14.94)	-3.66%
	4,000	$ 539.13	$ 519.27	$ (19.86)	-3.68%
	5,000	$ 670.09	$ 645.31	$ (24.78)	-3.70%
	6,000	$ 801.05	$ 771.35	$ (29.70)	-3.71%
	BFC	$ 10.91	$ 10.91	$ -	0.00%
	1st 800 KWH	$ 0.13644	$ 0.13129	$ (0.00515)	-3.77%
	Over 800 KWH	$ 0.13096	$ 0.12604	$ (0.00492)	-3.76%

Response to No. 1-21

ACCOUNT	DESCRIPTION
1010100	Elec Plant In Service
1010150	Elec Pis-sal Hydro Backup Dam
1010160	Electric - Plant In Service-de
1010180	Elec Pis For Arc- Non Ratebase
1010199	Elec Hold Asset Acct
1010200	Gas Plant In Service
1010206	Gas Plant In Service Arc
1011000	Property Under Capital Lease
1011001	Elec Prop Cap Lease Bushy Park
1011002	Elec Prop Cap Lease Parr
1020100	Elec Plant Purch
1020200	Gas Plant Purch Or Sold
1050100	Elec Plant Held Future Use
1060100	Compl Constr Not Classfd Elec
1060110	Compl Cnstr Not Cls_hgd Gs Tur
1060160	Elect-completed Constr No Clas
1060200	Gas Completed Constr Not Class
1070100	Constr Work In Prog Elec
1070200	Constr Work In Prog Cgt
1080100	Acc Depr Rwip Elec
1080101	Accum Depr Salv Elec
1080110	Acc Depr Of Elec Utility Plant
1080111	Acc Depr Elec Plt Resrv Transf
1080112	Accum Depr Cor Electric
1080120	Acc Depr Of Elect Ut Plt - Aro
1080150	Acc Depr Elec Ut Plt - Synfuel
1080160	Der Capital - Incremental
1080169	Acc Depr Elec Util Steam Genrt
1080180	Accum Depr Electric Pis - Arc
1080200	Accum Prov For Depre Gas
1080201	Accum Depr Cor Gas
1080206	Accum Prov For Depr-gas-arc
1080210	Depr Rwip Gas Contr
1080211	Accum Depr Salv Gas
1080220	Acc Prov For Depr-contr Rwip-g
1080221	Accum Depr Cor Prch Plnt Gas
1080222	Accum Depr Salv Prch Plnt Gas
1110000	Acc Amort-elec Utility Plant
1110001	Acc Pro Amt El Ut Plt Frch Fee
1110002	Acc Amt Sntry 9200 Syswo13982

1110003	Acc Amort Cape Softwar Wo13000
1110004	Acc Amort Today Softwar Wo1304
1110005	Acc Amt Impll Mntn Mgt Wo92319
1110006	Acc Amt Idms Db Licnse Wo16701
1110007	Acc Amort Proj Schdlng Wo16703
1110008	Acc Amort Sal Dam Mod Wo20373
1110009	Acc Amort Veproms Wo160128
1110010	Acc Amort Sys Simultr Wo130058
1110011	Acc Amt Vcs Redtg Sys Wo160079
1110012	Acc Amt Vcs Docstretr Wo160349
1110013	Acc Amt Vcs Vaxvmsop Wo160398
1110014	Acc Amt Eddy Net Sys Wo160388
1110015	Acc Amt Syscn Artecsii Wo13110
1110016	Acc Amort Vcs Ingress Wo160354
1110017	Acc Amort Scada Wo130232
1110018	Acc Amt Scada Hpm7000 Wo130250
1110019	Acc Amort Netsystask Wo160321
1110020	Acc Amort Mcmopersim Wo100275
1110021	Acc Amort Oas System Wo130067
1110022	Acc Amort Artecs Cs19 Wo130201
1110023	Acc Amort Outage Wo160609
1110024	Acc Amort Rms Wo160654
1110025	Acc Amort Special Wo160679
1110026	Acc Amort Doc Mgmt Wo160686
1110027	Acc Amt Wndowcougher1 Wo130364
1110028	Acc Amt Wndowcougher2 Wo130364

1110029	Acc Amt Scada Sys Upg Wo130368
1110030	Acc Amort Enpro Wo130255
1110031	Acc Amt Full Graphics Wo130209
1110032	Acc Amort Migration Wo130384
1110033	Acc Amort Inhouse Wo130200
1110034	Acc Amort Qnet Wo16640
1110035	Acc Amort Saipms Wo16640
1110036	Acc Amort Sds Wo16640
1110037	Acc Amort Rcm Wo160225
1110038	Acc Amort Iccpnet Wo130403
1110039	Acc Amort Interlink Wo130404
1110040	Acc Amort Interchange Wo130405
1110041	Acc Amort Hepms Wo160854
1110042	Acc Amort Rca Access Wo160857
1110043	Acc Amort Charleston Franchise
1110044	Acc Amort West Cougar Wo130365
1110045	Acc Amort Sbt Wo130453
1110046	Acc Amort Smart Meter Wo150417
1110047	Acc Amort Insights Wo130462
1110048	Acc Amort Rcs Cycle Wo160271
1110049	Acc Amort Dbase Wo160376
1110050	Acc Amort Emerpro Wo160838
1110051	Acc Amt Ops Planning Wo130300
1110052	Acc Amort Falls Wo130450
1110053	Acc Amt Outg Schdulng Wo160299
1110054	Acc Amt Transnt Anlst Wo160245
1110055	Acc Amt-champs Rewrt-wo160475
1110056	Acc Amt-fileimaging-wo160760
1110057	Acc-amt-his Sys Rewrt-wo160357
1110058	Acc-amt-smltr Certific-wo16008
1110059	Acc Amort Urq-dupont Cont
1110060	Contr Sys Upgrade Wo 100783
1110061	Acc Amort Obd1 Wo#100783
1110062	Acc Amort Must00001 #130532

1110063	Acc Amort Mmsmodule#160716
1110064	Acc Amort Dmis-fh
1110065	Acc Amort Dmis-in
1110066	Acc Amort Dmis-re
1110067	Acc Amort Dmis-nu
1110068	Acc Amort Dmis-gn
1110069	Mutimedia Train Wo 130505
1110070	Vcs Notification Wo 160970
1110071	Geographic Info. System
1110072	Industrial Trans System
1110073	Chemistry Mgt System
1110074	Fh Maintenance Mgt Urq
1110075	Fh Maintenance Mgt Mcm
1110076	Fh Maint Mgt Canadys
1110077	Fh Maint Mgt Wateree
1110078	Williams Maint Mgt
1110079	Penetration Seal Project
1110080	Ffp Maint Mgt System
1110081	Westvaco Gen Accum Prov
1110082	Fh Environ Dispatch Softwar
1110083	Fh Odbc Software Wo 130667
1110084	Nuc Ops Mgt System Wo160896
1110085	Vcs Cer Program Wo160956
1110086	Wmsoas Wo920229
1110087	Cis Datawarehouse Wo920229
1110088	Vcs Lifecyclemgt Wo161145
1110089	Sinautspectrum Ems Wo130479
1110090	Vacrinterregional Wo 130582
1110091	Vcs Filenetupgrade Wo161066
1110100	Acc Amt El Util Plt Rot Sht Pn
1110160	Acc Amort-electric Utility Pla
1110200	Acc Prov For Amort Gas
1110210	Acc Prov For Amort Contr Gas
1140000	Elec Plant Acq Adj
1140001	Gas Plnt Acquisition Adjustmnt
1140002	Pageland Lateral Acq Adjustmnt
1140003	Elec Plt Acq Adj Hagood Lm2500
1140004	Elec Plt Acq Adj Hagood Tm2500
1150000	Acc Amort-elec Plant Acq Adj
1150001	Accum Prov-amort Gas Plnt Acq
1150002	Accum Prov Amrt Paglnd Acq Adj
1150003	Acc Amor Acq Adj Hagood Lm2500

1150004	Acc Amor Acq Adj Hagood Tm2500
1172000	System Balancing Gas
1180210	Gas Plant In Service
1180212	Gas Pis For Arc- Non Ratebase
1180214	Utility Plant Capital Lease
1180219	Gas Holding Asset Account
1180250	Gas Plant Held For Future Use
1180260	Compl Constr Not Classified Ga
1180270	Constr Work In Prog Gas
1180294	Gas Plant Acquispsnc
1180295	Gas Plant Acquisscpc
1180410	Transit Plant In Service
1180419	Transit Hold Asset Account
1180460	Compl Constr Not Classified Tr
1180470	Constr Work In Prog Tran
1180710	Common Plant In Service
1180711	Common Plnt Alloc-plt In Srvc
1180712	Common Pis Arc- Non Ratebase
1180713	Common Prop Cap Lease Computer
1180714	Pc Capital Leases
1180715	Util Plant Under Capital Lease
1180719	Common Hold Asset Acct
1180750	Common Plant Held-future Use
1180760	Compl Const Not Clssfd Common
1180770	Const Work In Progress Common
1180771	Common Plant Allocated - Cwip
1190000	Accum Prov Amortization
1190001	Accum Prov For Amortization
1190002	Gas Plant Aquis Amort Scpc
1190003	Acc Amt Stckhlders Rec Wo92292
1190004	Acc Amt Proj Mgt Proj Wo92306
1190005	Acc Amt Human Res Sys Wo92330
1190006	Acc Amt Cullinet Dbms Wo92332
1190007	Acc Amt Hostgate Super Wo92359
1190008	Acc Amort Focus Wo92336
1190009	Acc Amort Ca Scheduler Wo92364

1190010	Acc Amort Isd Wo92388
1190011	Acc Amort Payroll Hr Wo92349
1190012	Acc Amort Data Mgt Sw Wo92390
1190013	Acc Amt Sys Monitorng Wo92391
1190014	Acc Amt Mgt Select Dev Wo92393
1190015	Acc Amort Prop Reco
1190016	Acc Amort Comp Draft
1190017	Acc Amort Risk Mgt Sw
1190018	Acc Amort Isd Endev Sw
1190019	Acc Amort Playbk Sw Wo920110
1190020	Acc Amt Flex Bnfit Sw Wo920136
1190021	Acc Amt Proj Mgmt Sw Wo920136
1190022	Acc Amort Xcom Sw Wo920175
1190023	Acc Amort Bfrs Sw Wo920133
1190024	Acc Amort Compuware 1 Wo920192
1190025	Acc Amort Compuware 2 Wo920192
1190026	Acc Amort Platinum Wo920192
1190027	Acc Amort Sybase Wo920227
1190028	Acc Amort Bachman Sw Wo920052
1190029	Acc Amt Isd Virus Sw Wo920216
1190030	Acc Amort Electronic Mail
1190031	Acc Amort Hresls Sw Wo920196
1190032	Acc Amort Erts Sw Wo920267
1190033	Acc Amort Amps Sw Wo920197
1190034	Acc Amort Edasql Sw Wo920119
1190035	Acc Amrt Firstcase Sw Wo920264
1190036	Acc Amrt Skillview Sw Wo920273
1190037	Acc Amort Cold Ii Sw Wo920315
1190038	Acc Amrt Pwr Builder Wo920318
1190039	Acc Amort Microfocus W0920250
1190040	Acc Amt Voice Inf Sys Wo920263
1190041	Acc Amort Group Sys V Wo920282

1190042	Acc Amt Imag Mgmt Srv Wo920225
1190043	Acc Amt Reg Act Doc Mgt#920302
1190044	Acc Amort Esr Sys Wo920362
1190045	Acc Amort Database2 Wo920391
1190046	Acc Amt Clear Support Wo920397
1190047	Acc Amort Auto System Wo920399
1190048	Acc Amort Midtier Wo920386
1190049	Acc Amort Glass Sw Wo280303
1190050	Acc Prov For Amort-gas Plant
1190051	Acc Amort Cics Wo920234
1190052	Acc Am-reltionaldata Wo920384
1190053	Acc Amt-micrsft Exchg Wo920429
1190054	Acc Amort Powerbl Wo#920433
1190055	Acc Amort Strobemsvr#920442
1190056	Acc Amort Platinum #920448
1190057	Acc Amort 10yrforcst#920466
1190058	Acc Amort Dmis
1190059	Acc Amort Dmis-ga
1190060	Acc Amort Virusd3200 920512
1190061	Acc Amort Sybase Wo 920526
1190062	Acc Amort Abendad Wo 920561
1190063	Acc Amort Vpspcl Wo 920534
1190064	Maintenance Wo 920564
1190065	Monitor Wo 920566
1190066	Isd Imaging Server Wo920387
1190067	Imaging Implement Wo 920449
1190068	Iss Dec Supp Sys Wo 920368
1190069	Inform Svcs Comet Wo 920501
1190070	Knowledgebase Wo 920513
1190071	Perform Monitor Wo 920524
1190072	Telephony Integ Wo 920418
1190073	Cis
1190074	Data Warehouse Cis
1190075	Meter Inventory Cis
1190076	Workmgt Sys Outage Analysis
1190077	Fax Remittance Process
1190078	Walker Web Enablement
1190079	Client Server Appl Response
1190080	Gis Stoner W O 280301
1190081	Gis Arcinfo W O 280301

1190082	Gis Mapeditview W O 280301
1190083	Rewritetimeentry W O 920674
1190084	Ca Variousupgrdes Wo 920673
1190085	Compuwareupgrade Wo 920673
1190086	Ibm Upgrade W O 920673
1190087	Programartupgrade Wo 920673
1190088	Assistgtbmsgt Wo 920673
1190089	Isd Networkreport Wo 920588
1190090	Teknektron W O 920418
1190091	Rewritedesktopappl Wo920675
1190092	Message Queing W O 920702
1190093	Trng And Develop Wo 920678
1190094	Nonutilitycreditmodwo920707
1190095	Server E Talk Wo 920714
1190096	Ent Net Monitor Phii 920676
1190097	Psnc Job Conv 920704
1190098	Cms Nt Tape Library 920661
1190099	Accum Depreciation N Chas Ops
1190210	Acc Depr Rwip Gas
1190211	Accum Depr Salv Gas
1190270	Acc Depr Of Gas Utility Plant
1190271	Accum Depr Cor Gas
1190272	Accum Depr Gas Pis - Arc
1190273	Accum Depr Cor Gas - Psnc
1190410	Acc Depr Rwip Transit
1190470	Acc Depr Of Transit Utility Pl
1190710	Acc Depr Rwip Common
1190711	Accum Depr Salv Common
1190770	Acc Depr Of Common Utility Pl
1190771	Common Plant Allocated-rsrv
1190772	Accum Depr Common Pis - Arc
1190773	Eg Comm Acc Depr Of Metro Plex
1190774	Eg Comm Acc Depr Of Metro Flex
1190775	Accum Depr Cor Common
1201000	Nuclear Fuel In Process
1201002	Nf In Proc Batch Tbd-conversio
1201003	Nf In Proc Batch Tbd-enrichmnt
1201004	Nf In Proc Batch Tbd-fabricat
1201005	Nf In Proc Batch Tbd-afudc
1201131	Nuc Fuel-proc Btch13 Fuel Cost
1201132	Nuc Fuel-proc Btch13 Convrsion

1201133	Nuc Fuel-proc Btch13 Enrichmnt
1201134	Nuc Fuel-proc Btch13 Fabrictn
1201135	Nuc Fuel-proc Btch13 Afudc
1201141	Nuc Fuel-proc Btch14 Fuel Cost
1201142	Nuc Fuel-proc Batch14 Convrsn
1201143	Nuc Fuel-proc Batch14 Enrchmnt
1201144	Nuc Fuel-proc Batch14 Fabrictn
1201145	Nuc Fuel-proc Batch14 Afudc
1201153	Nuc Fuel In Proc Batch 15 E
1201154	Nuc Fuel In Proc Batch 15 F
1201155	Nuc Fuel In Proc Batch 15 A
1201163	Nf In Proc Batch 16 En
1201164	Nf In Proc Batch 16 Fa
1201165	Nf In Proc Batch 16 Af
1201173	Nf In Proc Batch 17 En
1201174	Nf In Proc Batch 17 Fa
1201175	Nf In Proc Batch 17 Af
1201183	Nf In Proc Batch 18 En
1201184	Nf In Proc Batch 18 Fa
1201185	Nf In Proc Batch 18 Af
1201193	Nf In Proc Batch 19 En
1201194	1201194 Nf In Proc Batch 19 Fa
1201195	Nf In Proc Batch 19af
1201203	Nf In Proc Btch 20 Enr
1201204	Nf In Proc Batch 20 Fabricatio
1201205	Nf In Process Batch 20 Afudc
1201212	Nf In Proc Batch 21 Conversion
1201213	Nf In Proc Btch 21 Enr
1201214	Nf In Proc Btch 21 Fab
1201215	Nf In Proc Btch 21 Afc
1201222	Nf In Proc Batch 22 Conversion
1201223	Nf In Proc Batch 22 Enrichment
1201224	Nf In Proc Batch 22 Fabricatio
1201225	Nf In Process Batch 22 Afudc
1201232	Nf In Proc Batch 23 Conversion
1201233	Nf In Proc Batch 23 Enrichment
1201234	Nf In Proc Batch 23 Fabricatio
1201235	Nf In Process Batch 22 Afudc
1201242	Nf In Proc Batch 24 Conversion
1201243	Nf In Proc Batch 24 Enrichment
1201244	Nf In Proc Batch 24 Fabricatio
1201245	Nf In Process Batch 24 Afudc
1201252	Nf In Proc Batch 25 Conversion
1201253	Nf In Proc Batch 25 Enrichment
1201254	Nf In Proc Batch 25 Fabricatio

1201255	Nf In Process Batch 25 Afudc
1201262	Nf In Process Batch 26 Convers
1201263	Nf In Process Batch 26 Enrichm
1201264	Nf In Process Batch 26 Fabrica
1201265	Nf In Process Batch 26 Afudc
1201272	Nf In Proc Batch 27 Conversion
1201273	Nf In Proc Batch 27 Enrichmen
1201274	Nf In Proc Batch 27 Fabricatio
1201275	Nf In Proc Batch 27 Afudc
1201282	Nf In Proc Batch 28 Conversion
1201283	Nf In Proc Batch 28 Enrichment
1201284	Nf In Proc Batch 28 Fabricatio
1201285	Nf In Proc Batch 28 Afudc
1202000	Nuclear Fuel Stock
1202002	Nuclear Fuel Stock-conversion
1202003	Nuclear Fuel Stock-enrichment
1202004	Nuclear Fuel Stock-fabrication
1202005	Nuclear Fuel Stock-afudc
1202131	Nuc Fuel Stk Batch13 Fuel Cost
1202132	Nuc Fuel Stk Batch13 Convrsion
1202133	Nuc Fuel Stk Batch13 Enrichmnt
1202134	Nuc Fuel Stk Batch13 Fabrction
1202135	Nuc Fuel Stk Batch13 Afudc
1202141	Nuc Fuel Stk Batch14 Fuel Cost
1202142	Nuc Fuel Stk Batch14 Convrsion
1202143	Nuc Fuel Stk Batch14 Enrchment
1202144	Nuc Fuel Stk Batch14 Fabrction
1202145	Nuc Fuel Stk Batch 14 Afudc
1202153	Nuc Fuel Stk Batch 15 Enric
1202154	Nuc Fuel Stk Batch 15 Fabri
1202155	Nuc Fuel Stk Batch 15 Afudc
1202163	Nf Stk Batch 16 Enrich
1202164	Nf Stk Batch 16 Fabric
1202165	Nf Stk Batch 16 Afudc
1202173	Nf Stk Batch 17 Enrich
1202174	Nf Stk Batch 17 Fabric
1202175	Nf Stk Batch 17 Fabric
1202183	Nf Stk Batch 18 Enrich
1202184	Nf Stk Batch 18 Fabric
1202185	Nf Stk Batch 18 Afudc
1202193	Nf Stk Batch 19 Enrich
1202194	Nf Stk Batch 19 Fabric
1202195	Nf Stk Batch 19 Afudc
1202203	Nf Stock Batch 20 Enrichment
1202204	Nf Stk Batch 20 Fabrication
1202205	Nf Stk Batch 20 Afudc

1202212	Nf Stk Batch 21 Conver
1202213	Nf Stk Batch 21 Enrich
1202214	Nf Stk Batch 21 Fabric
1202215	Nf Stk Batch 21 Afudc
1202222	Nf Stock Batch 22 Conversion
1202223	Nf Stock Batch 22 Enrichment
1202224	Nf Stk Batch 22 Fabrication
1202225	Nf Stk Batch 22 Afudc
1202232	Nf Stock Batch 23 Conversion
1202233	Nf Stock Batch 23 Enrichment
1202234	Nf Stk Batch 23 Fabrication
1202235	Nf Stk Batch 23 Afudc
1202242	Nf Stock Batch 24 Conversion
1202243	Nf Stock Batch 24 Enrichment
1202244	Nf Stk Batch 24 Fabrication
1202245	Nf Stk Batch 24 Afudc
1202252	Nf Stock Batch 25 Conversion
1202253	Nf Stock Batch 25 Enrichment
1202254	Nf Stk Batch 25 Fabrication
1202255	Nf Stk Batch 25 Afudc
1202262	Nf Stock Batch 26 Conversion
1202263	Nf Stock Batch 26 Enrichment
1202264	Nf Stock Batch 26 Fabrication
1202265	Nf Stock Batch 26 Afudc
1202272	Nf Stock Batch 27 Conversion
1202273	Nf Stock Batch 27 Enrichment
1202274	Nf Stk Batch 27 Fabrication
1202275	Nf Stk Batch 27 Afudc
1202282	Nf Stock Batch 28 Conversion
1202283	Nf Stock Batch 28 Enrichment
1202284	Nf Stock Batch 28 Fabrication
1202285	Nf Stock Batch 28 Afudc
1203000	Nuclear Fuel In Reactor
1203101	Nuc Fuel Rctr Btch10 Fuel Cost
1203102	Nuc Fuel-rctor Batch10 Convrsn
1203103	Nuc Fuel-rctr Batch10 Enrchmnt
1203104	Nuc Fuel-rctr Batch10 Fabrctn
1203105	Nuc Fuel-reactor Batch10 Afudc
1203111	Nuc Fuel-rctr Btch11 Fuel Cost
1203112	Nuc Fuel-rctr Batch11 Cnvrsion
1203113	Nuc Fuel-rctr Batch11 Enrchmnt
1203114	Nuc Fuel-rctr Batch11 Fabrctn
1203115	Nuc Fuel-reactor Batch11 Afudc
1203121	Nuc Fuel-rctr Btch12 Fuel Cost
1203122	Nuc Fuel-rctr Batch12 Convrsn
1203123	Nuc Fuel-rctr Batch12 Enrchmnt
1203124	Nuc Fuel-rctr Batch12 Fabrctn

1203125	Nuc Fuel-reactor Batch12 Afudc
1203131	Nuc Fuel-rctr Btch13 Fuel Cost
1203132	Nuc Fuel-rctr Batch13 Convrsn
1203133	Nuc Fuel-rctr Batch13 Enrchmnt
1203134	Nuc Fuel-rctr Batch13 Fabrctn
1203135	Nuc Fuel-reactor Batch13 Afudc
1203141	Nuc Fuel-rctr Btch14 Fuel Cost
1203142	Nuc Fuel-rctr Batch14 Convrsn
1203143	Nuc Fuel-rctr Batch14 Enrchmt
1203144	Nuc Fuel-rctr Batch14 Fabrctn
1203145	Nuc Fuel-reactor Batch14 Afudc
1203153	Nuc Fuel In Reac Batch 15 E
1203154	Nuc Fuel In Reac Batch 15 F
1203155	Nuc Fuel In Reac Batch 15 A
1203163	Nf In Reac Batch 16 En
1203164	Nf In Reac Batch 16 Fa
1203165	Nf In Reac Batch 16 Af
1203173	Nf In Reac Batch 17 En
1203174	Nf In Reac Batch 17 Fa
1203175	Nf In Reac Batch 17 Af
1203183	Nf In Reac Batch 18 En
1203184	Nf In Reac Batch 18 Fa
1203185	Nf In Reac Batch 18 Af
1203193	Nf In Reac Batch 19 Enrich
1203194	Nf In Reac Batch 19 Fabric
1203195	Nf In Reac Batch 19 Af
1203203	Nf In Reactor Batch 20 Enrich
1203204	Nf In Reactor Batch 20 Fabric
1203205	Nf In Reactor Batch 20 Afudc
1203212	Nf In Reac Btch 21 Conv
1203213	Nf In Reac Btch 21 Enr
1203214	Nf In Reac Btch 21 Fab
1203215	Nf In Reac Btch 21 Afc
1203222	Nf In Reactor Batch 22 Conver
1203223	Nf In Reactor Batch 22 Enrich
1203224	Nf In Reactor Batch 22 Fabric
1203225	Nf In Reactor Batch 22 Afudc
1203232	Nf In Reactor Batch 23 Conver
1203233	Nf In Reactor Batch 23 Enrich
1203234	Nf In Reactor Batch 23 Fabric
1203235	Nf In Reactor Batch 23 Afudc
1203242	Nf In Reactor Batch 24 Conver
1203243	Nf In Reactor Batch 24 Enrich
1203244	Nf In Reactor Batch 24 Fabric
1203245	Nf In Reactor Batch 24 Afudc
1203252	Nf In Reactor Batch 25 Conver
1203253	Nf In Reactor Batch 25 Enrich

1203254	Nf In Reactor Batch 25 Fabric
1203255	Nf In Reactor Batch 25 Afudc
1203262	Nf In Reactor Batch 26 Conver
1203263	Nf In Reactor Batch 26 Enrich
1203264	Nf In Reactor Batch 26 Fabric
1203265	Nf In Reactor Batch 26 Afudc
1203272	Nf In Reactor Batch 27 Conver
1203273	Nf In Reactor Batch 27 Enrich
1203274	Nf In Reactor Batch 27 Fabric
1203275	Nf In Reactor Batch 27 Afudc
1203282	Nf In Reactor Batch 28 Conv
1203283	Nf In Reactor Batch 28 Enrich
1203284	Nf In Reactor Batch 28 Fabric
1203285	Nf In Reactor Batch 28 Afudc
1204000	Spent Nuclear Fuel
1204101	Spent Nuc Fuel Btch10 Fuel Cst
1204102	Spent Nuc Fuel Batch10 Convrsn
1204103	Spent Nuc Fuel Batch10 Enrchmt
1204104	Spent Nuc Fuel Batch10 Fabrctn
1204105	Spent Nuc Fuel Batch 10 Afudc
1204111	Spent Nuc Fuel Btch11 Fuel Cst
1204112	Spent Nuc Fuel Batch11 Convrsn
1204113	Spent Nuc Fuel Batch11 Enrchmt
1204114	Spent Nuc Fuel Batch11 Fabrctn
1204115	Spent Nuc Fuel Batch 11 Afudc
1204121	Spent Nuc Fuel Btch12 Fuel Cst
1204122	Spent Nuc Fuel Batch12 Convrsn
1204123	Spent Nuc Fuel Batch12 Enrchmt
1204124	Spent Nuc Fuel Batch12 Fabrctn
1204125	Spent Nuc Fuel Batch 12 Afudc
1204131	Spent Nuc Fuel Btch13 Fuel Cst
1204132	Spent Nuc Fuel Batch13 Convrsn
1204133	Spent Nuc Fuel Batch13 Enrchmt
1204134	Spent Nuc Fuel Batch13 Fabrctn
1204135	Spent Nuc Fuel Batch 13 Afudc
1204141	Spent Nuc Fuel Btch14 Fuel Cst
1204142	Spent Nuc Fuel Batch14 Convrsn

1204143	Spent Nuc Fuel Batch14 Enrchmt
1204144	Spent Nuc Fuel Batch14 Fabrctn
1204145	Spent Nuc Fuel Batch 14 Afudc
1204153	Spent Nuc Fuel Batch 15 Enr
1204154	Spent Nuc Fuel Batch 15 Fab
1204155	Spent Nuc Fuel Batch 15 Afu
1204163	Spent Nf Batch 16 Enri
1204164	Spent Nf Batch 16 Fabr
1204165	Spent Nf Batch 16 Afud
1204173	Spent Nf Batch 17 En
1204174	Spent Nf Batch 17 Fabr
1204175	Spent Nf Batch 17 Afud
1204183	Spent Nf Batch 18 Enri
1204184	Spent Nf Batch 18 Fabr
1204185	Spent Nf Batch 18 Afud
1204193	Spent Nf Batch 19 Enri
1204194	Spent Nf Batch 19 Fabr
1204195	Spent Nf Batch 19 Afud
1204203	Spent Nf Batch 20 Enrichment
1204204	Spent Nf Batch 20 Fabrication
1204205	Spent Nf Btch 20 Afudc
1204212	Spent Nf Batch 21 Conv
1204213	Spent Nf Batch 21 Enri
1204214	Spent Nf Batch 21 Fabr
1204215	Spent Nf Btch 21 Afudc
1204222	Spent Nf Batch 22 Conversion
1204223	Spent Nf Batch 22 Enrichment
1204224	Spent Nf Batch 22 Fabrication
1204225	Spent Nf Batch Afudc
1204232	Spent Nf Batch 23 Conversion
1204233	Spent Nf Batch 23 Enrichment
1204234	Spent Nf Batch 23 Fabrication
1204235	Spent Nf Batch 23 Afudc
1204242	Spent Nf Batch 24 Conversion
1204243	Spent Nf Batch 24 Enrichment
1204244	Spent Nf Batch 24 Fabrication
1204245	Spent Nf Batch 24 Afudc
1204252	Spent Nf Batch 25 Conversion
1204253	Spent Nf Batch 25 Enrichment
1204254	Spent Nf Batch 25 Fabrication
1204255	Spent Nf Batch 25 Afudc
1204262	Spent Nf Batch 26 Conversion
1204263	Spent Nf Batch 26 Enrichment
1204264	Spent Nf Batch 26 Fabrication
1204265	Spent Nf Batch 26 Afudc
1204272	Spent Nf Batch 27 Conversion

1204273	Spent Nf Batch 27 Enrichment
1204274	Spent Nf Batch 27 Fabrication
1204275	Spent Nf Batch 27 Afudc
1204282	Spent Nf Batch 28 Conversion
1204283	Spent Nf Batch 28 Enrichment
1204284	Spent Nf Batch 28 Fabrication
1204285	Spent Nf Batch 28 Afudc
1205000	Acc Pro Nuclear Fuel Amort
1205101	Acc Pro Nu Amt Btch10 Fuel Cos
1205102	Acc Pro Nu Amt Btch10 Convrsn
1205103	Acc Pro Nu Amt Btch10 Enrchmnt
1205104	Acc Pro Nu Amt Btch10 Fabrctn
1205105	Acc Pro Nu Amt Btch10 Afudc
1205111	Acc Pro Nu Amt Btch11 Fuel Cos
1205112	Acc Pro Nu Amt Batch11 Convrsn
1205113	Acc Pro Nu Amt Batch11 Enrchmt
1205114	Acc Pro Nu Amt Btch11 Fabrctn
1205115	Acc Pro Nu Amt Btch11 Afudc
1205121	Acc Pro Nu Amt Btch12 Fuel Cos
1205122	Acc Pro Nu Amt Btch12 Convrsn
1205123	Acc Pro Nu Amt Btch12 Enrchmnt
1205124	Acc Pro Nu Amt Batch12 Fabrctn
1205125	Acc Pro Nu Amt Batch12 Afudc
1205131	Acc Pro Nu Amt Btch13 Fuel Cos
1205132	Acc Pro Nu Amt Btch13 Convrsn
1205133	Acc Pro Nu Amt Btch13 Enrchmnt
1205134	Acc Pro Nu Amt Btch13 Fabrctn
1205135	Acc Pro Nu Amt Btch13 Afudc
1205141	Acc Pro Nu Amt Btch14 Fuel Cos
1205142	Acc Pro Nu Amt Btch14 Convrsn
1205143	Acc Pro Nu Amt Btch14 Enrchmnt
1205144	Acc Pro Nu Amt Btch14 Fabrctn
1205145	Acc Pro Nu Amt Btch14 Afudc
1205153	Acc Pro Nf Amort Batch15 En
1205154	Acc Pro Nf Amort Batch15 Fa

1205155	Acc Pro Nf Amort Batch15 Af
1205163	Ac Pro Nf Amort #16 En
1205164	Ac Pro Nf Amort #16 Fa
1205165	Ac Pro Nf Amort #16 Af
1205173	Ac Pro Nf Amort 17 En
1205174	Ac Pro Nf Amort 17 Fa
1205175	Ac Pro Nf Amort 17 Af
1205183	Ac Pro Nf Amort 18 En
1205184	Ac Pro Nf Amort 18 Fa
1205185	Ac Pro Nf Amort 18 Af
1205193	Ac Pro Nf Amort 19 Enr
1205194	Ac Pro Nf Amort 19 Fa
1205195	Ac Pro Nf Amort 19 Af
1205203	Acc Prov Nf Amort 20 Enrichmnt
1205204	Acc Prov Nf Amort 20 Fabricat
1205205	Acc Prov Nf Amort 20 Afudc
1205212	Ac Pro Nf Amort 21 Con
1205213	Ac Pro Nf Amort 21 Enr
1205214	Ac Pro Nf Amort 21 Fab
1205215	Ac Pro Nf Amort 21 Afc
1205222	Acc Prov Nf Amort #22 Conversi
1205223	Acc Prov Nf Amort #22 Enrich
1205224	Acc Prov Nf Amort #22 Fabricat
1205225	Acc Prov Nf Amort #22 Afudc
1205232	Acc Prov Nf Amort #23 Conversi
1205233	Acc Prov Nf Amort 23 Enrich
1205234	Acc Prov Nf Amort 23 Fabrica
1205235	Acc Prov Nf Amort 23 Afudc
1205242	Acc Prov Nf Amort #24 Conversi
1205243	Acc Prov Nf Amort 24 Enrich
1205244	Acc Prov Nf Amort 24 Fabrica
1205245	Acc Prov Nf Amort 24 Afudc
1205252	Acc Prov Nf Amort #25 Conversi
1205253	Acc Prov Nf Amort#25 Enrich
1205254	Acc Prov Nf Amort#25 Fabrica
1205255	Acc Prov Nf Amort#25 Afudc
1205262	Acc Prov Nf Amort 26 Convers
1205263	Acc Prov Nf Amort 26 Enrich
1205264	Acc Prov Nf Amort 26 Fabric
1205265	Acc Prov Nf Amort 26 Afudc
1205272	Acc Prov Nf Amort #27 Convers
1205273	Acc Prov Nf #27 Enrich
1205274	Acc Prov Nf Amort #27 Fabrica
1205275	Acc Prov Nf Amort #27 Afudc
1205282	Acc Prov Nf Amort 28 Conv
1205283	Acc Prov Nf Amort 28 Enrich

1205284	Acc Prov Nf Amort 28 Fabric
1205285	Acc Prov Nf Amort 28 Afudc
1210100	Nonutility Property
1210101	Non-util S-tax
1210199	Nonutil Hold Asset Acct
1210200	Nonutility Proprty
1210300	Nonutil Prop Cap Res
1210301	Pc Capital Leases
1210600	Cmplt Cnstr Not Clss Nutl&nreg
1210700	Constr Work In Prog Non Util
1220000	Reserve For Accum Depr
1220100	Acc Amrt & Depr Non-utlty Prop
1220101	Accum Depr Cor Non Utility
1220110	Non Utility&non Regulated Rwip
1220111	Accum Depr Salv Non Util & Non
1220200	Acc Amt Nonutl Prop Pcleas Imp
1220300	Acc Amt Nonutl Prop Case Tools
1220350	Acc Amort Nonutil Prop Scri
1220400	Acc Amort Dmis-sc
1220450	Sec Ser Benefit Wo 929067
1220500	Scanabillingsystemwo 929126
1220550	Elec Bill Present Wo 929129
1220600	Scana Callcentersftw 929127
1220650	Pvcs Conversion Wo929134
1220700	Csf Messenger S W Wo929151
1220750	Psnc Job Conversion 920704
1220751	E Business Supersite 929141
1220752	E Business Large Ind 929148
1230000	Invest In Assoc Co- Advances
1230003	Inv In Assoc Co-adv-semi
1230005	Inv In Assoc Co-adv-spr
1230013	Inv In Assoc Co-eg Jr Sub D
1230038	Non-interest Adv To Schi
1230044	Other Inv Apog Llc
1231000	Invest Associated Co
1231001	Inv In Assoc Cos-securities
1231002	Invst Assc Co Adv-advs-scana
1231044	Other Inv Apog Llc
1231101	Invest In Sub Co Sec Svci
1231102	Invest In Sub Co Sec Sps
1231103	Invest In Sub Co Sec Semi
1231104	Invest In Sub Co Sec Psi

1231105	Invest In Sub Co Sec Spr
1231106	Invest In Sub Co Sec Sdc
1231107	Invest In Sub Co Sec Scpc
1231108	Invest In Sub Co Sec Spg
1231109	Invest In Sub Co Sec Sci
1231110	Invest In Sub Co Sec Scfc
1231113	Invest In Sub Co Sec Sceg
1231114	Invest In Sub Co Sec Genco
1231115	Invest In Sub Co Sec Sr
1231116	Invest In Assoc Co-sceg Trust1
1231117	Invst-assoc Co-sceg Jr Sub Deb
1231120	Inv In Assoc Co-sceg Ti
1231125	Invest In Sub Co West Texas
1231128	Invest In Sub Co Sec Psnc
1231129	Invest In Sub Co Service Com
1231132	Invest In Sub Co Pscp
1231133	Invest In Sub Co Blue
1231134	Invest In Sub Co Prod
1231135	Invest In Scg Pipeline
1231136	Invest In Sub Co Clean
1231137	Investment In Sub Co Sec Scss
1231201	Invest In Sub Co Adv Svci
1231202	Invest In Sub Co Adv Sps
1231203	Invest In Sub Co Adv Tirzah
1231204	Invest In Sub Co Adv Psi
1231205	Invest In Sub Co Adv Spr
1231206	Invest In Sub Co Adv Sdc
1231207	Invest In Sub Co Adv Scpc
1231208	Invest In Sub Co Adv Spg
1231209	Invest In Sub Co Adv Sci
1231210	Invest In Sub Co Adv Scfc
1231213	Invest In Sub Co Adv Sceg
1231214	Invest In Sub Co Adv Genco
1231215	Invest In Sub Co Adv Sr
1231216	Invest In Sub Co Adv-sr-1-step
1231217	Invst In Sub Co Adv Sr Accu
1231218	Inv In Sub Adv Sr-solo
1231228	Invest In Sub Co Adv Psnc
1231229	Invest In Sub Adv Services Co
1231230	Invest In Sub Adv - Sc
1231235	Invest In Scg Pipeline-advan
1231250	Inv In Sub Co Adv Sr Online
1231251	Advance To Retailco
1231256	Invest In Sub Co Adv Sega
1231257	Invest In Sub Co Adv Set
1231258	Invest In Sub Co Adv Sch
1231305	Allow Impairment In Invest Spr

1231306	Allow Impairment In Invest Sdc
1231401	Invest-sub Co Non Int Adv Svci
1231403	No Intrst Advcs-scana Enrg Mkt
1231404	Invest-sub Co Non Int Adv Psi
1231405	Invest-sub Co Non Int Adv Spr
1231406	Invest-sub Co Non Int Adv Sdc
1231407	Invest In Sub Co Non Scpc
1231409	Invest-sub Co Non Int Adv Sci
1231410	Invest In Sub Co Non Scfuel
1231413	Invest In Sub Co Non Sceg
1231414	Invest In Sub Co Non Genco
1231415	Invest-sub Co Non Int Adv Sr
1231428	Invest In Psnc Noninterest
1231429	Non Int Adv To Service
1231432	Invest In Sub Co Non Pscp
1231433	Invest In Sub Co Non Blue
1231435	Invest In Scg Pipeline-nonin
1231436	Invest In Sub Co Non Clean
1231456	Invest In Sub Co Non Int Ga
1231457	Invest In Sub Co Non Set
1231458	Invest In Sub Co Non Sch
1231460	Inv In Sub-canadys Refined Coa
1231461	Inv In Sub-brandon Shores
1231462	Inv In Sub-louisa Refined Coal
1231463	Inv In Sub-brunner Island Refi
1240000	Other Investments
1240001	Oth Inv Pal Seed Cap Corp
1240002	Oth Inv Pal Seed Cap Fund
1240003	Other Investments Eib
1240004	Allow Impair General
1240005	Oth Inv Res Equip Scri
1240006	Oth Inv Pat Res Equip Scri
1240007	Oth Inv Avdata Sys Scri
1240008	Oth Inv Bus Dev Corp Cap Resrc
1240009	Oth Inv Res Equip Eq Scri
1240010	Allow Impair Invest Res Scri
1240011	Allow Impair Pat Res Scri
1240012	Oth Inv Econ Dev Authority
1240013	Other Invstmts Emssion Allwncs
1240014	Investments In Instel-goodwill
1240015	Invest In Cdm Resource Mgmt
1240016	Other Investments-rabbi Trust
1240017	Investment In Palmetto Lime
1240018	Investment In Cogen South
1240019	Notes Rec Palmetto Lime
1240020	Oth Invest Synfuel-wat

1240021	Invest In Cogen South Equit
1240022	Investment In Rabbi Trust
1240023	Investment In Itcd
1240024	Invest In Asheville Cty Club
1240025	Invest In Atlanta Gas Light
1240026	Invest In Cardinal Club
1240027	Invest In Cp&l
1240028	Invest In Croasdaile Cty Club
1240029	Invest In Dominion Res
1240030	Invest In Duke Power
1240031	Invest In Piedmont Nat Gas
1240032	Invest In Raleigh Cty Club
1240033	Invest In Roxboro Cty Club
1240034	Invest In United City Gas
1240035	Invest In Pine Needle Lng
1240036	Invest In Cardinal Extension
1240037	Investment Itcd-warrants
1240038	Oth Invest Synfuel-cdy
1240039	Investments -edcp
1240040	Kerp Cash Surrender Value
1240041	Kerp Csv - Hartford Plan
1240042	Dir Endowment Csv
1240043	Other Inv Nustart
1240044	Other Inv Apog Llc
1240045	Investment In Westex Renew
1240046	Investment In Rabbi Trust-kerp
1240048	Invest In Winn Dixie Stk
1240049	Unrealized G L On Winn Dixie
1240050	Investment In Schi
1240051	Investment-canadays Refined Co
1240052	Investment-cope Refinded Coal
1240053	Investment - Brandon Shores Co
1240054	Investment - Louisa Refined Co
1240055	Concepts To Companies Llc
1240056	Investment Brunner Island Refi
1240057	Accessible Diagnostics
1240073	Investment In Prod Sps
1240074	Investment In Frc Llc
1240076	Investment In Sci Holding
1280015	Other Special Funds-trust Loan
1280205	Other Special Funds-trust Cash
1280206	Other Special Funds-trust-csv
1310000	Cash
1310001	Cash - Bank Of America

1310002	Capital Bank
1310003	Cash - Bb&t
1310004	Cash - Carolina Bank
1310005	Cash - Chase Sce&g
1310006	Cash - First Citizens Bank
1310007	Cash-first National Bank Of Sc
1310008	Cash - Nbsc
1310009	Cash - Regions Bank
1310010	Cash - S C Bank And Trust
1310011	Cash - Wachovia First Union
1310012	Enterprise Bank
1310013	Cash- Non-utility Money Pool
1310014	Cash-utility Money Pool
1310015	Cash-wachovia Refund Acct-ga
1310016	Cash-wachovia Apay-ga
1310017	Cash-sci-wells Fargo
1310018	Cash-schi-td Bank
1310100	Csh Trnfr Btwn Sc & Eg Units
1310101	Scana Services - Pay Pal
1310110	Cash - Winyah
1310200	Csh Trnfr Btwn Sh & Eg Units
1310300	Csh Trnfr Btwn Eg & Psnc Units
1310301	Cash Trnfr Btwn Clean & Oth
1310400	Csh Trnfr Btwn Sh & Sc Units
1310500	Csh Trnfr Btwn Sh & Psnc Units
1310600	Csh Trnfr Btwn Sc & Psnc Units
1310660	Scana Services-cc-wells Fargof
1310700	Cash Sc Disbursements
1310800	Csh Trnfr Btwn Svci & Sceg
1310801	Csh Trnfr Btwn Svci & Sc
1310802	Csh Trnfr Btwn Svci & Sh
1310803	Csh Trnfr Btwn Svci & Psnc
1310804	Cash Wash Westex And All Sceg
1310805	Cash Wash Westex And Scana Ser
1310806	Cash Wash Westex And Scana Hol
1310807	Cash Tranfr Btwn Svci And Sega
1310901	Csh Trnfr Btwn Eg & Gen Eag
1310902	Csh Trnfr Btwn Eg & Re Eag
1310903	Csh Trnfr Btwn Eg & Ga Eag
1310904	Csh Trnfr Btwn Eg & In Eag
1310905	Csh Trnfr Btwn Gen And Re Eag
1310906	Csh Trnfr Btwn Gen & Gas Eag
1310907	Csh Trnfr Btwn Gen And In Eag
1310908	Csh Trnfr Btwn Re And Gas Eag

1310909	Csh Trnfr Btwn Re And In Eag
1310910	Csh Trnfr Btwn Gas And In Eag
1310915	Cash-transf Between Sega&serg
1310916	Csh Trnfr Betwn Semic And Sega
1310917	Csh Trnfr Betwn Semic And Cgt
1310918	Csh Trnfr Betwn Sega And Cgt
1310920	Csh Trnfr Betwn Semic And Eg
1310921	Csh Trnfr Betwn Semic And Sc
1310922	Csh Trnfr Betwn Semic And Sh
1310923	Csh Trnfr Betwn Semic And Psnc
1310930	Csh Trnfr Betwn Sega And Eg
1310931	Csh Trnfr Betwn Sega And Sc
1310932	Csh Trnfr Betwn Sega And Sh
1310933	Csh Trnfr Betwn Sega And Psnc
1310940	Csh Trnfr Betwn Cgt And Eg
1310941	Csh Trnfr Betwn Cgt And Sc
1310942	Csh Trnfr Betwn Cgt And Sh
1310943	Csh Trnfr Betwn Cgt And Psnc
1310950	Cash Transfer B/t Sci & Eg
1310951	Cash Transfer B/t Sci & Sc
1310952	Cash Transfer B/t Sci & Sh
1310953	Cash Transfer B/t Sci & Psnc
1310954	Cash Transfer B/t Sci And Cgt
1311000	Cash - Winyah
1311001	Scana Services - Pay Pal
1312000	Cash Sc Dispursements
1330000	Div Special Deposits
1340000	Oth Special Dep - Insurance
1340001	Spec Dep Pur Emp Sav Bonds
1340002	Spec Dep Pur Of Matur Bonds
1340003	Spec Dep Pur Of Prf Stock
1340004	Spec Dep Workers Comp
1340005	Spec Dep Suppl Refund Expand F
1340006	Spec Dep Suppl Refund Pend App
1340007	Spec Dep Suppl Refund Expand F
1340008	Other Special Dep Series A
1340009	Other Special Dep Series B
1340010	Special Deposits - Heritage
1340011	Margin Deposit - Ssb
1340012	Other Special Deposits Usbank
1340013	Margin Deposits

1340014	Cash - Escrow Customer Deposit
1340015	Deposit-ind Rev Bonds-gn Scrub
1340016	Other Spec Dep-wachovia
1340017	Other Spec Dep - Boa
1340018	Other Spec Dep - Wells Fargo
1340019	Oth Sp Dep Bnk Of Ny Mellon
1340020	Other Spec Dep-boa 100m 125m
1340021	Oth Sp Dep - Mizuho 100m
1340022	Other Special Deposit - Cc - W
1340023	Other Spec Dep Cs
1340024	Other Spec Dep Jp Morgan
1340025	Oth Sp Dep - Union Bank
1340026	Oth Sp Dep - Mizuho
1340027	Oth Sp Dep - Morgan Stanley
1340028	Oth Sp Dep Ubs 231/232/237
1340029	Oth Sp Dep - Td Bank
1340030	Other Spec Deposits - Us Bank
1340034	Cash Escrow For Like Kind Exch
1340100	Oth Spec Mort Prop - Release
1340101	Special Deposits - 35m Irb
1340102	Special Deposits 36 4m Irb
1350000	Perm Working Funds
1350001	Temp Working Funds
1350002	Cashier Working Funds
1350003	Imprest Funds
1350004	Imprest Funds Cigna
1350005	Payroll Working Fund
1350006	Petty Cash Working Fund
1350007	Special Acct Working Fund
1350008	Psnc Suppl Refund Working Fund
1350009	Right Of Way Working Fund
1350010	Perf Adj Gnrl Liab Working Fun
1350011	Perf Adj Work Comp Work Fund
1350012	Psnc Health Ins Working Fund
1350013	Psnc Emp Ben Working Fund
1350014	Psnc Zenith Ins Working Fund
1350015	Psnc Apay Working Fund
1350016	Psnc Cis Refund Working Fund
1350017	Imprest Checking Account
1360000	Temp Cash Investments
1360001	Psnc Hedges - Market Value
1360002	Psnc Hedges - Contra Account

1360003	Broker Margin Wires In Out
1360004	Broker Margin End Of Month
1369000	Temp Cash Inv Georgia Gas
1410000	Notes Receivable
1410001	Notes Rec Se Aviation
1410002	Notes Rec Res Equip Scri
1410003	Nt Rec 12% Dem Note Scri
1410004	Investment In Cdm Note 1
1410005	Investment In Cdm Note 2
1410006	Note Receivable Palmetto Lime
1410007	Receivable From Sci
1410009	Sci-note Receivable From Schi
1420000	Cust Ar Miscellaneous
1420001	Cust Ar Installment Sales
1420003	Ar-non-associated Transportati
1420004	Cust Ar Emer Repair
1420006	Ar Psnc Gas Customers
1420007	Ar Non-utility M&j
1420008	Ar Pending Revenue
1420009	Ar Pending Def Interest
1420010	Ar Pending Tax
1420011	Ar Psnc Heat Care Donations
1420012	Accounts Receivable-semic
1420013	Accounts Receivable-estimated
1420014	Ar Unapplied Cash Account
1420015	Unapplied Cash-treasury
1420016	Non-interst Adv To Schi
1420050	Customer Ar Liheap
1420110	Cust Ar Old Cis Edp
1420112	Cust Ar Cis Sales & Non Util
1420113	Special Provision-customer Rec
1420114	Cust Ar Cis Sales & Non Util-s
1420120	Cust Ar Old Cis Ibs
1420122	Ar Transfers On Cis
1420125	Cons Billing Transfers On Cis
1420130	Cust Ar Old Cis Non Edp
1420135	Ar - Heartland Payment Systems
1420136	Ar - Rate 135 Manual Billings
1420137	Ap Rinnai Lowe's Referral Prog
1420140	Cust Ar Old Cis Gbs
1420150	Cust Ar Consolid Billing
1420200	Cust Ar Interchange & Wheeling

1420201	Wholesale Fuel Clause Under Co
1420390	Cust Ar Unbilled Rev
1420391	Cust Ar Unbilled Rev-sega Serg
1420392	Cust Ar Unbilled Rev-segr
1420393	Cust Ar Unbilled Rev Agl & Svc
1420394	Cust Ar Unbilled Rev Agl & Svc
1420499	Ar Deferred Imbalances
1429000	Cust Ar Seb Cis
1429999	Ar Control Account
1430000	Oth Acct Rec Misc
1430001	Oth Ar Other
1430002	Oth Ar Telecom To Sci
1430003	Oth Ar Cainhoy Park
1430004	Oth Ar Lrl Crest Retire Ctr
1430005	Oth Ar Central Midlnds Planng
1430006	Oth Ar Land
1430007	Other Ar Sps Cpl
1430008	Oth Ar Accutrack
1430009	Billing/credit Card Recvables
1430010	Other Ar Emp Financ Vehicle
1430011	Other Ar Computer Lease
1430012	Ar Mcdonald Corp
1430013	Cash Escrow For Like Kind
1430014	Oth Ar Group Purchases
1430015	Oth Ar Gas Brokering
1430016	Oth Ar Psnc Apay
1430017	Oth Ar Special Fuels
1430018	Oth Ar Psnc Leases
1430019	Oth Ar Psnc Misc
1430020	Oth Ar Psnc Ciac
1430021	Oth Ar Dam Reimbursable Costs
1430022	Oth Ar Cash Calls
1430023	Oth Ar Franchise
1430024	Employee Loan - Ee Plans
1430025	Hedges - Broker Ar
1430026	Other Ar Psa - Scfc Invoices
1430027	Oth Ar - Otc Hedging
1430028	Oth Ar Gas Sold
1430029	Oth Ar - Mgp Ins Settlement
1430030	Acct Receivable-plant Acctg
1430031	Ar Long Upstream Oba Imbalanc
1430032	Ar Misc -cnnga Pass Thru Charg
1430033	Ar Misc -grnwd Pass Thru Charg
1430034	Ar Misc -agl Ldc Transport Cha

1430035	Ar Misc - Guc Pass Thru Charge
1430036	Ar Misc - Fpas
1430037	Ar Misc -grnmd Option Fv
1430038	Ar Other -agency Rec-chas Plac
1430039	Ar Semi - Ga Seb-not Eliminati
1430040	Ar Misc -ga Sales Tax Refund
1430041	Ar Misc - Psc Refunds
1430042	Ar Misc-cnnga Inventory Ar
1430043	Other Ar - Landlord Payments
1430044	Other Ar - Monroe Pipeline
1430045	Misc Accts Rec-ga Dor Pmt
1430046	Misc Acct Rec-ga Dor Refund
1430047	Othr Ar - Monroe Pipe Cab Ire
1430048	Other Ar - Rg Billing
1430049	1430049 A/r - Mmu - Lmc
1430050	Ar Misc-ga Sales Tax Est Pmt
1430051	A/r - Refunds From Ajg-s45
1430052	Rp Over Under Group 1 Asset
1430053	Group 1 Under Collection
1430054	Rp Over/under Group 2 Asset
1430055	Ar-ge Jasper $705k
1430060	Federal Inc Tax Receivable
1430061	State Inc Tax Receivable
1430100	Oth Ar Claims
1430102	Oth Ar Ltd
1430104	Oth Ar Small Tools Contract
1430105	Other Ar Cintas Uniforms
1430106	Other Ar Emp Life Plus Loan
1430107	Other Ar Emp Life Plus Tax
1430108	Other Ar Rus Uniforms
1430109	Other Ar Unifirst Uniforms
1430110	Other Ar Brunson Uniforms
1430111	Other Ar Chas Garage
1430112	Oth Ar City Of Chas Ug Line
1430113	Employee Garnishments
1430114	Taxable Tuition
1430115	Misc Employee Insurance
1430116	Financial Planning
1430117	Emp Rec Club Dues
1430118	Union Dues
1430119	Employee Club Dues
1430120	Other Ar Chas Garage L-t Rec
1430121	Oth Ar - G&k Uniforms
1430122	Accts Rec Scana Services Tele
1430123	Ar-other Vendors-telecommunica
1430124	Ar-spirit Telecom

1430125	Other Ar Dominion Rent Toc/fob
1430126	Accts Rec Telecom Tower Rental
1430130	Acct Receivable-sng Water Htr
1430131	Other Ar Cog Cashouts
1430200	Oth Ar Psa O And M
1430201	Oth Ar Psa Cap Wo16xxxx
1430202	Oth Ar Psa Cap Wo Dir Charge
1430203	Oth Ar Psa Vcs Stores Exp
1430204	Oth Ar Psa Vcs Inventory
1430205	Oth Ar Psa Nnd-vcs Units 2and3
1430206	Oth Ar Psa Opeb
1430207	Oth Ar Psa Retire Wk In Prgrss
1430208	Ar Psa Non Bill Refuel Accrl
1430209	Oth Ar Facilities Chgs Tenants
1430215	Psnc Other A/r I&j Claims
1430218	Interdiv Due To From Cash Adv
1430300	Oth Ar York Triath Consortium
1430301	Oth Ar York Triath Rebates
1430302	Oth Ar Sr
1430400	Cust Ar Liheap Prior Years
1430401	Cust Ar Liheap Curr Year
1430499	Ar Deferred Imbalances
1430500	Other Ar-columbia And Chas Vou
1430501	Oth Ar Agcy Vouch Chas
1430502	Oth Ar Agcy Voucher Psnc
1430503	Third Party Agency Rec
1430600	Oth Ar Cable Owip Billings
1430601	Acct Rec-cog Adj
1430602	Acct Rec - Marketer True Up
1430701	Ar-sci-non Affiliate-fiber
1430702	Ar-sci-affiliate-fiber
1430703	Ar Sci Non Affiliate Tower
1430704	Ar Sci Affiliate Tower
1430705	Ar Sci Non Affiliate Admin
1430706	Ar Sci Affiliate Admin
1430708	Ar-sci-misc Ar
1430709	Ar Sci Pmn Revenue Sharing
1430710	Ar Sci Sst Interco Corrections
1439999	Oth Ar Jnt Own Csh Trnsfr
1440000	Acc Prov Uncoll Acct Cis
1440001	Acc Prov Uncol Act Comp Gas Cu
1440002	Allow For Uncollect Accounts
1440003	Acc Prv Uncol Act Res Equ Scri

1440004	Acc Prov-uncoll Acct-take/pay
1440005	Acc Prov Uncoll Palmetto Li
1440006	Acc Prov Uncoll Psnc Gas Cr
1440007	Acc Prov Uncoll Mdse Cr
1440008	Acc Prov Uncoll Pwr Marketing
1440009	Acc Prov Uncollect Svci
1440010	Acc Prov Uncollect Calpine
1440011	Acc Prov Uncollect Georgia Unb
1440012	Allow For Uncollectible Ar
1440013	Acc Prov Uncollect Georgia Unb
1440014	Acc Prov Uncollect Georgia Seb
1440015	Anticipated Uncollected Clms
1440016	Acc Prov Uncoll Marketer Trueu
1440017	Acc Prov Uncollect Ga Seb-segr
1440600	Acc Prov Uncoll Acct Cableowip
1443000	Allowance For Uncollect Accts
1450000	Notes Rec From Assoc Co
1450003	Notes Receivable Assoc Co-shc
1450029	Lt Note Reveivable - Sc
1460000	Ar From Assoc Co
1460001	Ar Assoc Co Svci
1460002	Scana Propane Billing Acct
1460003	Ar Assoc Co Semi
1460004	Ar Assoc Co Psi
1460005	Ar Assoc Co Spr
1460006	Ar Assoc Co Sdc
1460007	Ar Assoc Co Cgtc
1460008	Ar Assoc Co Spg
1460009	Ar Assoc Co Sci
1460010	Ar Assoc Co Scfc
1460012	Accts Recvble Assoc Co's-scana
1460013	Ar Assoc Co Sceg
1460014	Ar Assoc Co Genco
1460016	Ar Assoc Co Fh
1460017	Ar Assoc Co - Nuclear Fuel
1460018	Ar Assoc Co Ga
1460019	Ar Sceg - Industrial
1460020	Ar Assoc Co-sce&g Trust I
1460024	Ar Assoc Co Clean Energy
1460028	Ar Assoc Co Psnc
1460029	Ar Assoc Co Scana Services
1460030	Ar Assoc Co Scana Security
1460031	Accts Rec Delaware Sch
1460032	Ar Assoc Co Pscp
1460033	Ar Assoc Co Blue Ridge
1460035	Ar Assoc Co Scg Pipeline
1460040	Ar Assoc Due From Sega

1460041	Ar Assoc Due From Serg
1460042	Ar Production Co
1460100	Ar Assoc Co Scpc Triath Rebate
1460101	Ar Assoc Co Genco Bill Sceg
1460102	Ar Assoc Co Scpc Pay Taxes
1460103	Ar Assoc Co-from Sc Fuel Co
1460107	Ar Assoc Co-scpc Bonus
1460118	Ar Assoc Co Ga -hedging
1460200	Ar Assoc Co Prosolutions
1460201	Ar Assoc Co Instel
1460202	Ar Assoc Co One Step
1460206	Ar Assoc Co Georgia Divisn
1460207	Ar Assoc Co Cgtc
1460208	Ar Assoc Co Sega Regulated
1460215	Ar Assoc Co Accutrack
1460216	Scana Online Energy
1460218	Accts Recv Assoc Cos Solo
1460219	Accounts Receivable - Bppb
1460220	Ar Assoc Co Bppb/psnc
1460221	Ar Assoc Co Bppb/sega
1460222	Ar Assoc Co Bppb/sceg
1460229	Advances To Nu Pool
1460303	Assoc A/r - Semi
1460305	Trusti Accts Rec Assoc Co-sceg
1460307	Ar Assoc It Revenue - Scpc
1460318	Ar Assoc Co Cgt
1460329	Interest Receivable - Nu Pool
1460335	Ar Assoc It Revenue - Scg
1460500	Ar Production Co
1460516	Accrued Interest Lt Note Payab
1460529	Accrd Int Lt Note Rec - Sc
1460530	Accrd Int Lt Note Rec - Sc
1461001	Inter Co Receivable Svci Apay
1461010	Inter Co Receivable Scfc Apay
1461012	Inter Co Receivable Sh Apay
1461013	Inter Co Receivable Eg Apay
1461014	Inter Co Receivable Gn Apay
1461016	Inter Co Receivable Fh Apay
1461017	Inter Co Receivable Nu Apay
1461018	Inter Co Receivable Ga Apay
1461019	Inter Co Receivable In Apay
1461020	Inter Co Receivable T1 Apay
1461021	Inter Co Receivable Re Apay
1461022	Inter Co Receivable Tr Apay
1461023	Inter Co Receivable Fl Apay
1461028	Inter Co Receivable Psnc Apay
1461029	Nu Money Pool Int On Adv - Sc

1461032	Inter Co Receivable-blue-apay
1461033	Inter Co Receivable Clean Apay
1461034	Inter Co Receivable Pscp Apay
1461035	Inter Co Receivable Wtex Apay
1461036	Inter Co Receivable Cgt Apay
1461037	Inter Co Receivable Sega Apay
1461038	Inter Co Receivable Serg Apay
1461039	Inter Co Receivable Semp Apay
1461040	Inter Co Receivable Semic Apay
1461041	Inter Co Rcv Sci Apay
1461118	Ar Assoc Co Gas
1461203	Ar Assoc Co - Semi P And B
1461206	Ar Assoc Co - Sega P And B
1461207	Ar Assoc Co - Scpc P And B
1461209	Ar Assoc Co - Sci P And B
1461211	Ar Assoc Co - Svci P And B
1462001	Nu Money Pool Advances - Svci
1462003	Nu Money Pool Advances - Semi
1462004	Nu Money Pool Advances - Psi
1462006	Nu Money Pool Advances - Sdc
1462007	Nu Money Pool Advances - Scpc
1462008	Nu Money Pool Advances - Spg
1462009	Nu Money Pool Advances - Sci
1462010	Money Pool Advances - Scfc
1462013	Utility Money Pool Adv - Eg
1462014	Utility Money Pool Adv - Genco
1462015	Ar Assoc Co Sr
1462018	Nu Money Pool Advances - Solo
1462028	Money Pool Advances - Psnc
1462029	Nu Money Pool Advances - Sc
1462035	Nu Money Pool Advances - Scg
1462050	Nu Money Pool Advances-online
1462056	Nu Money Pool Advances - Sega
1463001	Nu Pool Int On Adv - Svci
1463003	Nu Pool Int On Adv - Semi
1463004	Nu Pool Int On Adv - Psi
1463006	Nu Pool Int On Adv - Sdc
1463007	Nu Pool Int On Adv - Scpc
1463008	Nu Pool Int On Adv - Spg
1463009	Nu Pool Int On Adv - Sci
1463013	Utility Pool Int On Adv-eg

1463014	Utility Pool Int On Adv-genco
1463015	Nu Pool Int On Adv - Sr
1463018	Nu Pool Int On Adv - Solo
1463029	Nu Pool Int On Adv - Sc
1463035	Nu Pool Int On Adv - Scg
1463050	Nu Pool Int On Adv - Online
1463056	Nu Pool Int On Adv - Sega
1464001	Ar Assoc Co Accrl-svci
1464003	Ar Assoc Co Accrl-semi
1464004	Ar Assoc Co Accrl-psi
1464007	Ar Assoc Co Accrl-scpc
1464009	Ar Assoc Co Accrl-sci
1464013	Ar Assoc Co Accrl-eg
1464026	Ar Assoc Co Accrl-sega
1464028	Ar Assoc Co Accrl-psnc
1464035	Ar Assoc Co Accrl-scg
1465050	Ar Affiliated Co Synfuel
1465051	Ar Affil Co-canadys Ref Coal
1465052	Ar Affiliated Co-cope Refined
1510000	Fuel Stock Coal
1510051	Fuel Stock Furn Oil Lng
1510100	Fuel Stock No2 Fuel Oil
1510200	Fuel Stock No6 Fuel Oil
1510300	Fuel Stock Recy Fuel Oil
1510400	Fuel Stock Propane
1510500	Fuel Stock L P Gas
1540000	Plnt Matls And Oper Supplies
1540001	Matl And Supplies Print Dept
1540002	Gas Meters And Reg Inv
1540003	Plnt Matls And Oper Sup Vcs
1540004	M&s Psnc Gas Diesel Prop Inv
1540005	M&s Psnc Small Tools And Supp
1540006	Fleet Parts Inventory
1540007	Corp Security Parts Inventory
1540008	Prescription Drug Inventory
1540009	Plant Materials & Supplies
1540100	M And S Inv Recpts Cost Var
1540200	Walker Dummy Stk Acct
1540300	Inventory In Transit
1540400	M And S Inventory
1540410	Invent Work In Process-pipes
1540909	M And R Material Inventory
1540910	Gasoline Inventory
1540911	Cathodic Protection Inventory
1540912	Measurement Devices Inventory

1540913	Jasper Inventory
1540914	Compression Inventory
1540919	Jet Fuel Inventory
1540970	Emergency Pipe Inventory
1540975	Half Sole Inventory - North
1540980	Pipe Inventory
1540985	Half Sole Inventory - South
1540987	Operations Inventory
1540995	Communications Equip Inventory
1540996	Odorant Southern Comp Station
1540997	Odorant Jasper
1550000	Merch Inventory
1550001	Merch Inv Appliance Parts
1550010	Invent Work In Process - Merch
1550011	Invent Work In Process - Appli
1581000	Nox Ozone Cair Allow Inv Cp
1581001	Nox Ozone Cair Allow Inv Lt
1581002	So2 Arp Allow Inv Cp
1581003	So2 Arp Allow Inv Lt
1581004	Emis Allow Inv Curr Portion
1581005	Nox Annual Cair Inv Cp
1581006	Nox Annual Cair Inv Lt
1581007	S02 Csapr Allow Inv Cp
1581008	S02 Csapr Allow Inv Lt
1581009	Nox Ozone Csapr Inv Cp
1581010	Nox Ozone Csapr Inv Lt
1581011	Nox Annual Csapr Allow Inv Cp
1581012	Nox Annual Csapr Allow Inv Lt
1582000	Allowances Withheld
1630000	Stores Exp
1641000	Nat Gas&propane Stock Inventry
1641001	Natural Gas Inventory-cnnga
1641002	Natural Gas Inventory-greenwoo
1641003	Natural Gas Inventory-odpu
1641004	Natural Gas Inventory-bennetts
1641005	Natural Gas Inventory-bamberg
1641006	Natural Gas Inventory-winnsb
1641007	Natural Gas Inventory-petal
1641008	Natural Gas Inventory-tyson
1641009	Greenwood Inventory - Wss
1641010	Greenwood Inventory - Ess

1641011	Gas Storage-transco Gss
1641012	Natural Gas Inv-union Wss
1641013	Gas Storage-transco Wss
1641014	Natural Gas Inv-union Ess
1641015	Gas Storage - Saltville
1641016	Inventory - Greenwood Petal
1641017	Gas Storage-dti
1641018	Gas Storage-ess
1641019	Gas Storage-eminence
1641020	City Of Wrens Inventory
1641021	Clinton Newberry Ess Inventory
1641024	Gas Storage-tco-columbia
1641100	Transco Wss Gas Storage
1641200	Sonat Css Gas Storage
1641300	Transco Ess Gas Storage
1641400	Transco Gss Gas Storage
1641500	Inventory - Natural Gas
1641510	Natural Gas Inventory-sng
1641520	Natural Gas Inventory-transco
1641530	Natural Gas Inventory-agl Peak
1641540	Natural Gas Inventory-petal Bu
1641600	Sonat Lng Oba Gas Storage
1641700	Sonat Pal Gas Storage
1641800	Transco Ess 9050454 Gas Stor
1642010	Liq Ng Stored- Salley Lng
1642011	Liq Ng Stored Transco Gss Inv
1642012	Liq Ng Stored- Bushy Park Lng
1642013	Liq Ng Stored Transco Wss Inv
1642015	Gas Stored - Saltville
1642017	Liq Ng Stored Dti Gss Inv
1642018	Liq Ng Stored Transco Ess Inv
1642019	Gas Storage - Eminence
1642021	Liq Ng Stored Transco Lga Inv
1642023	Liq Ng Stored-cove Point
1642024	Liq Ng Stored Cola Fss Inv
1642025	Liq Ng Stored-pine Needle
1642031	Liq Ng Stored - Psnc Cary
1642100	Transco Wss Gas Storage
1642200	Southern Css Gas Storage
1642300	Transco Ess Gas Storage
1642400	Transco Gss Gas Storage
1642500	Transco Lng Gas Storage
1642600	Sonat Lng Oba Gas Storage
1642700	Sonat Pal Gas Storage
1643023	Liq Ng Held Cove Pt Lng Inv
1643025	Liq Ng Held Pine Needle Lng

1643031	Liq Ng Held Lng Inv
1643100	Lng Inventory Bushy Park
1643107	Lng Inventory Assoc Co Cgtc
1643110	Inv Parked Gas Supply
1643200	Lng Inventory Salley
1650000	Prepayments - Misc
1650001	Prepay Fuel Interest
1650002	Prepay Interest Allowances
1650003	Prepay Ferc Annual Bill
1650004	Prepay Turbine Parts Warranty
1650005	Title V Air Ems Fee
1650006	Prepay Int On Commer Paper
1650007	Prepayments- Leases
1650008	Prepaid Acct For Hydro Usgs
1650009	Neal Shoals Ferc Fees
1650010	Prepay Hydro Water Sampler
1650011	Prepay Int Funb
1650012	Prepay Int Bank Of America
1650013	Prepay Int Wachovia
1650014	Prepay Int Sun Trust
1650015	Prepay Int Centric
1650016	Prepay Res Chg Pine Needle
1650017	Prepay Transco Dep Momentum
1650018	Prepaid-software Agreement
1650019	Prepay Srs Water Sewer
1650020	Postage
1650021	Ferc - Annual Billing Charges
1650022	Prepay Bus License
1650023	Prepay Insurance
1650024	Arise Boiler Inspection
1650025	Misc Prepay - Health Care
1650026	Prepay Warranty For Cdys Dozer
1650027	Prepaid Safety User Fees
1650028	Prepaid Aca Charges
1650029	Prepaid Right Of Way Expenses
1650030	Misc Pipeline Maint Contracts
1650031	Prepay-professional Services
1650032	Prepayments-corp Sponsorships
1650033	Prepayments - Entertainment
1650034	Prepay-contracts And Agreement
1650035	Prepayments- Ingaa
1650036	Prepay-bbt-annual Loc-fees
1650037	Prepay-loc Fee Boa-genco Irb

1650038	Prepaid Buildout Expenses
1650039	Prepay-synergee Gas Soft-maint
1650040	Prepay-witnesscall Soft Maint
1650041	Prepaid Liability Insurance
1650042	Record Prior Yr Csts In Cur Yr
1650043	Prepayments - Naesb
1650044	Prepay - Power Advocate
1650045	Prepay Hp Hardware Support
1650046	Prepay Cgt Avaya Charges
1650047	Prepay Uptime Maintenance Fee
1650048	Prepay-custsvc Software Agrmts
1650049	Prepay Overnite Software
1650050	Prepay-op Support Agrmts
1650051	Prepay Uptime Main Fee Additio
1650052	Sega - Aiken Lease
1650053	Prepaid Warranty Costs
1650059	Airplane 1 Maint Contract
1650060	Prepay Cayce License Fee
1650061	Prepaid Tax Software
1650078	Semi-1330 Lady St Deferred Ren
1650079	Airplane 2 Maint Contract
1650100	Prepay-eprocurement Software
1650101	Prepayments Netiq Corp
1650102	Prepay Oracle Corp
1650103	Prepay Crime Bond
1650104	Prepay Crime Bond Contra
1650105	Prepay Ariba Software
1650106	T And D Insurance
1650107	Professional Liability - Pharm
1650108	General Liability - Emp Clubs
1650109	Prepay Ins Br Fee Aegis D O
1650110	Prepay Ins Brokr Fee Contra
1650111	Prepay Direct & Offic Liablty
1650112	Prepay Drct & Off Liab Contra
1650113	Prepay Gas Install Bond
1650114	Medical Stop Loss
1650115	Prepay - Merant
1650116	Neil Primary Policy Contra
1650117	Prepay Nuc Prop Excess Neil Ii
1650118	Prpy Nu Prop Excss Neilii Cntr
1650119	Prepay - Lucent Technologies

1650120	Prepay-ms Upgrade Advantage
1650121	Prepay Nuc Liab Facility Form
1650122	Prpy Nu Liab Faclt Form Contra
1650123	Prepay Nuclear Liab Sfp
1650124	Prepay Nuc Liab Sfp Contra
1650125	Prepay Nu Supp & Transporters
1650126	Prepay Nu Supp & Trans Contra
1650127	Prepay Prop All Risk
1650128	Neil Primary Policy Premium
1650129	Prepay Publc Liab & Prop Damge
1650130	Prepay Sct Software Maint
1650131	Prepay Sc Liq Petro Gas Dealer
1650132	Nuclear Extra Exp Premium
1650133	Nuclr Extra Exp Prem Contra
1650134	Prepay - Network General
1650135	Prpy Wrk Cmp Slf Insr Sc Cntra
1650136	Prepay Work Comp Slf Insure Ga
1650137	Prepay Sc Pub Weighmastr Board
1650138	Prepay-ibm-aix
1650139	Prepay Carotek
1650140	Prepay Comm Pest Appl License
1650141	Prepay Work Comp Policy Excess
1650142	Prpy Wrk Cmp Polcy Excss Cntra
1650143	Prepay Nucl Work Policy
1650144	Prepay Nucl Work Policy Contra
1650145	Prepay Ncr
1650146	Peoplesoft Maint Contract
1650147	Prepay Gt Software Inc
1650148	Prepay-dimension Data-oms
1650149	Power Plant Maint Contract
1650150	Prepay Kerp Group I
1650151	Prepay Kerp Group Ii
1650152	Prepay Kerp Group Iii
1650153	Prepay Kerp Group Iv
1650154	Prepay Kerp Group V
1650155	Prepay Kerp Group Vi
1650156	Prepay Kerp Group Vii And Ix
1650157	Prepay Kerp Group Viii
1650158	Prepay Kerp Group X
1650159	Prepay Kerp Group Xi

1650160	Prepay Kerp Group Xii
1650161	Prepay Kerp Group Xiii
1650162	Prepay Kerp Group Xiv
1650163	Prepay Kerp Group Xv
1650164	Prepay Storage Tech Co
1650165	Prepay - Corp Exec Board
1650166	Prepay Computer Assoc
1650167	Prepay-websource Inc
1650168	Prepay Microsoft Entrpze
1650169	Prepay Platinum Software
1650170	Prepay - Ibm Software Maint
1650171	Prepay-cisco Maintenance
1650172	Prepay Fiduc And Emp Ben Liab
1650173	Prepy Fid & Emp Ben Liab Cntra
1650174	Prepay Sybase Maint
1650175	Prepay Microsoft Maint
1650176	Prepay Compuware Maint
1650177	Prepay Peoplesoft Maint
1650178	Prepay Softbase Sys Maint
1650179	Prepay Hp Maint
1650180	Prepay Cofed Life Ins Premiums
1650181	Prepay Comp Assoc Int Inc
1650182	Prepay Clarify Maint
1650183	Prepay Bmc Software Maint
1650184	Prepay Ibm 3900 Printer
1650185	Prepay Lndmrk Sys Sftwre Lc
1650186	Prepay Sybase Sftwre Supprt
1650187	Prepay The Bradshaw Group
1650188	Prepay Embarcadero Technol
1650189	Prepay Sas Institute
1650190	Prepay Emc Software Maint
1650191	Prepayment Emc Corporation
1650192	Prepay Ca Tng Maint
1650193	Prepayments Netg Contract
1650194	Prepayments Netg Contract
1650195	Prepayments Level 8 Systems
1650196	Prepay Levi Ray And Shoup
1650197	Prepay Ibm Hardware Maint
1650198	Prepay Compuware Soft Psnc
1650199	Prepay Network Assoctes Inc
1650200	Prpy Fed Hwy Motor Veh Use Tax
1650201	Prepay Auto And Truck Licenses
1650202	Prepay Poe Licenses
1650203	Prepay Transit Licenses

1650204	Prpy Auto & Truck Veh Prop Tax
1650205	Prepay Tran Veh Prop Tax
1650206	Prepay St Spec Util License
1650207	Prepay St Gross Rcpt Tax
1650208	Prepay St License Fee
1650209	Prepay Vcs Prop Tax
1650210	Prepay Taxes & Priv Lic
1650211	Prepay - Support Of Psc
1650212	Prepaid Margin Deposits
1650213	Carrier Service Agreement
1650214	Prepaid-futures Cntrct Cf-st
1650215	Prepaid-futures Contr Nh-st
1650216	Prepaid-futures Contr Cf-lt
1650217	Prepaid-futures Contr Nh-lt
1650225	Pike Anon Environmental Insura
1650226	Prepaid License-maintenance
1650230	Renewables Prepaid Contracts
1650297	Prepay Crm/salesforce Cloud
1650300	Prepay Mun Lic Prior Yr Elec
1650301	Prpy Mun Lic Coll Cur Yr Elec
1650302	Ppd Mun Lic Pmt Cur Yr Elec
1650303	Prepay Mun Lic Prior Yr Gas
1650304	Ppd Mun Lic Coll Cur Yr Gas
1650305	Ppd Mun Lic Pmt Cur Yr Gas
1650351	Prepaid - HP iSCSI
1650401	Prepay Crime & Fiduciary Liab
1650402	Prepay Excess Laib Ins Layer 1
1650403	Prepay Excess Laib Ins Layer 2
1650404	Prepay Workplace Violence Ins
1650405	Prepay - Moodys Investor Serv
1650406	Prepay-trendmicro
1650407	Prepay - Cognos Maint
1650408	Prepay - Macro 4
1650409	Prepay - Citrix Softwr
1650410	Prepay - Metavante
1650411	Prepay - Giga
1650412	Prepay-renwl Fee On Comm Paper
1650413	Prepay Scada Maint
1650414	Prepay - Harvest Maint
1650415	Prepay - Magic Maint
1650416	Prepay Veritas Softwr
1650417	Prepaid Dsg Software
1650418	Prepaid Dsg Hardware
1650419	Prepaid Candle Maint

1650420	Prepay Storagetek
1650421	Prepay 500 Mips
1650422	Prepay Bpwin Er Win Maint
1650423	Prepay Alteris Maint
1650424	Prepay Allen Sys Maint
1650425	Prepay Symantec Maint
1650426	Prepay - Neon Systems
1650427	Prepay - Diversified Sft
1650428	Prepay Quest Software
1650429	Prepay - Avaya
1650430	Prepay Filenet Maint
1650431	Prepay - Ins Prem From Semi
1650432	Prepay Vmware Maint
1650433	Emc Storage
1650434	Prepay - Commitment Fees
1650435	Prepay Compuware Mts
1650436	Prepay Lurhq
1650437	Prepay-qei Hardwr Softwr Maint
1650438	Prepay Emc Training
1650439	Prepay - Ironmail
1650440	Prepay - Forrester
1650441	Prepay Maxware Maint
1650442	Prepay Ca Unicntr Trn
1650443	Prepay Emc Autoswap
1650444	Prepay Sirius Svcsuite
1650445	Prepay 21st Century
1650446	Prepay Compwre Sch 24
1650447	Prepay Vmware Virtual
1650448	Prepay Princeton Maint
1650449	Prepay Gardium Maintenance
1650450	Prepay Sirus Tape Silo
1650451	Prepay Global Knwl Trn
1650452	Prepaid Upfront Commitment Fee
1650453	Prepaid - Sirius - Ibm 2066
1650454	Prepaid - Strategic Techn
1650455	Prepaid - Dell - F5
1650456	Prepaid - Configuresoft Inc
1650457	Prepaid - Business Objects Ame
1650458	Prepaid - Clearwell Systems
1650459	Prepaid - Peoplesoft License
1650460	Prepaid - Peoplesoft Maintenan
1650461	Prepaid - Forrester-research
1650462	Prepaid - Zantaz Inc

1650463	Prepay Arise Boiler
1650464	Prepaid - Asg Software Solutio
1650465	Prepaid - Sc Insurance Contra
1650466	Prepaid - Exstream
1650467	Prepaid - Dino Software
1650468	Prepaid - Facetime
1650469	Arise Boiler Inspection
1650470	Prepayment Commitment Fees
1650471	Ppd Administrative Agent Fees
1650472	Ppd Admin Agent Fees-em Allow
1650473	Prepaid - Opentech Systems
1650474	Prepaid - Dts Software
1650475	Prepaid - Rsa Archer
1650476	Prepaid - Admn Agent Fees
1650477	Prepaid - Ibm - Nortel
1650478	Prepaid - Infoprint Solutions
1650479	Prepaid - Trend Micro
1650480	Prepaid - Secure Computing
1650481	Prepaid Com Fees - Bbt
1650482	Dolphin Software Serv Agreemen
1650483	Prepaid - Emc Teradata
1650484	Prepaid - Adtech Global
1650485	Prepaid - Websense
1650486	Prepaid - Emc Back Up
1650487	Prepaid - Capax
1650488	Prepaid - Weblogic
1650489	Prepaid - Component One
1650490	Prepaid - Infoblox
1650491	Prepaid - Red Hat
1650492	Prepaid - Avamar
1650493	Prepaid - Siem
1650494	Prepaid - Insight
1650495	Prepaid - Configuresoft - Vm
1650496	Prepaid - Dynamix
1650497	Prepaid - Sms
1650498	Prepaid - Oracle True-up
1650499	Prepay Admin Agent Fees
1650500	Prepaid Jasper Gas Resv Fee
1650501	Prepaid-admn Agent Fee-3yr Ann
1650502	Prepaid Commitment Fees-3yr-cu
1650503	Prepaid - Cyber Liability
1650505	Prepaid - Teradata
1650506	Prepaid - Emc 2014 Big Deal

1650510	Prepayment - Other Compensatio
1650511	Prepaid - Proofpoint
1650512	Prepaid - Hp Quality
1650513	Preraid - Ca - Mf Upgrade
1650514	Prepaid - Shavlik
1650515	Prepaid - Nas
1650516	Prepaid - Palo Alto
1650517	Prepaid - Source Fire
1650518	Prepaid - Entrust
1650519	Prepaid - Microsoft-eci
1650520	Prepaid - Q-radar
1650521	Prepaid - Ca Gigastor
1650522	Prepad - Mvs Quick Ref
1650523	Prepaid - Emc 2012 Refresh
1650524	Repaid - Dynamix Mf
1650525	Prepaid - Ibm Maximo
1650526	Prepaid - Netmotion Wireless
1650527	Prepaid - Apcon
1650528	Prepaid - Microsoft Office 365
1650529	Prepay Tips Maintenance
1650530	Prepaid - Oracle Rac
1650531	Prepaid - Hp Iscsi
1650532	Prepaid - Verint
1650533	Prepaid - Bmc Footprints
1650534	Prepaid - Telerik
1650535	Prepaid - Hpt Xtremio
1650536	Prepaid - Bmc Perf Reporting
1650537	Prepaid - Sea Jclplus Xref Plu
1650538	Prepaid - Solarwinds
1650539	Prepaid - Gartner Inc
1650540	Prepaid -cisco Ela
1650541	Prepaid Microsoft Dse
1650542	Prepaid Palo Alto Cip5
1650543	Prepaid Gigastor Ada
1650544	Prepaid Entrust Cert Mgmnt
1650545	Prepaid Kofax
1650546	Prepaid Q Radar Cip5
1650547	Prepaid Tripwire Cip5
1650548	Prepaid Ist Miscellaneous
1650549	Prepaid 2015 Emc Big Deal
1650550	Prepaid Bit9-carbblk For Isoc
1650551	Prepaid Wildfire Apt For Isoc
1650552	Prepaid-hp Carepacks
1650553	Prepaid-tele Avaya
1650554	Prepaid - Airwatch
1650555	Prepaid - Cisco Cip

1650556	Prepaid - Micro Focus
1650557	Prepaid - Dynatrace
1650558	Prepaid - Training Concepts
1650559	Prepaid - Hp Printer Software
1650560	Prepaid - Rubricks
1650600	Pp Custsvc Wausau Amort
1650601	Pp Custsvc Salesforce Amort
1650701	Pp Sci N Augusta Consent Fee
1650702	Pp Sci Arin Internet Subscript
1650703	Pp Sci Sce&g Yemassee Grnd Ls
1650704	Pp Sci At&t Cola/chs Conduit
1650705	Pp Sci Sce&g Pole Attachments
1650706	Pp Sci Tri Cnty Pole Attachmen
1650707	Pp Sci Obrg Dpu Pole Attachmen
1650708	Pp Sci Pc Partnership Gen Pad
1650709	Pp Sci Lattis Software Subscri
1650710	Pp Sci Mcgriff Pole Attach Bnd
1650711	Pp Sci Blanchard Gen Warranty
1650712	Pp Sci Blanchard Cat3516 Ups M
1650713	Pp-sci-esri Gis Software Licns
1650714	Pp Sci Eatn Ups Pwrwr 9390 Mnt
1650715	Pp Sci Cisco Smrtnt 15600 Mnt
1650716	Pp-sci-cisco-virtual Dark Fib
1650717	Pp Sci Cisco Smrtnt Me10720 Mn
1650718	Pp Sci Parking Spaces At Hub
1650719	Pp Sci Snee Farm Row Grnd Ls
1650720	Pp Sci City Of Gtown Grnd Ls
1650721	Pp Sci Camden Rd Gl
1650722	Pp Sci Byrd Askeville Grnd Ls
1650723	Pp Sci Coward Grnd Ls
1650724	Pp-sci-ms Joint Venture Em&l
1650725	Pp-sci-sceg-141 Meeting St
1650726	Pp-sci-sceg-#1 Charlotte
1650727	Pp-sci-pelzer Gl
1650728	Pp-sci-coopers Creek Gl
1650729	Pp-sci-smoaks Gl
1650730	Pp-sci-lake Murray Gl
1650731	Pp-sci-hudsons Mill Gl
1650732	Pp-sci-bolen Town Gl
1650733	Pp-sci-islandton Mill Gl
1650734	Pp-sci-hampton Gl
1650735	Pp-sci-cades Gl
1650736	Pp-sci-gallimore Dairy Gl
1650737	Pp Sci 87n Grnd Ls

1650738	Pp-sci-kershaw Pal800 Gl
1650739	Pp-sci-black Creek Gl
1650740	Pp-sci-dunlop Grnd Ls
1650741	Pp-sci-kingstree Gl
1650742	Pp-sci-hilda Gl
1650744	Pp-sci-midway Gl
1650745	Pp-sci-denmark South Gl
1650746	Pp-sci-lynchburg Gl
1650747	Pp-sci-ruffin Gl
1650748	Pp-sci-west Chester Gl
1650749	Pp-sci-hunting Camp Gl
1650750	Pp-sci-chavistown Gl
1650751	Pp-sci-beaver Creek Gl
1650752	Pp-sci-irth Software Maint
1650753	Pp-sci-irth Sw Maint #2
1650754	Pp-sci-ciena Communications
1650755	Pp-sci-chs Defns Contr Assn
1650756	Pp-sci-north Augusta Gl
1650757	Pp-sci-pontiac Gl
1650758	Pp-sci-purrysburg Gl
1650759	Pp-sci-shakespeare Gl
1650760	Pp-sci-whipple Road Gl
1650761	Pp-sci-ash Pond Gl
1650762	Pp-sci-holly Hill Gl
1650763	Pp-sci-ne Rocky Mount Gl
1650764	Pp-sci-ground Leases
1650765	Pp-sci-winding Bluff Gl
1650766	Pp-sci-yemassee Tower Gl
1650767	Pp Sci Cherokee Spring Gl
1650768	Pp Sci Craggie Tower Gl
1650769	Pp Sci Grays Chapel Gl
1650770	Pp Sci Lake Robinson Tower
1650771	Pp Sci Green South Gl
1650772	Pp Sci Hejaz Tower Gl
1700001	Unbilled Revenue-svci
1710000	Int And Div Receivable
1710001	Int & Div Rec Res Eqp Cap Rsrc
1710002	Int-dv Rec Res Eqp Dem Nt Scri
1710003	Int-div Rec Se Aviation Note
1710005	Int And Div Res Palmtto Lim
1710006	Ar Short-term Int Inc Amended
1730000	Accrued Utility Revenues
1730001	Accr Util Rev Res-ewna
1730002	Accr Util Com - Ewna
1730003	Unbilled Revenue-svci
1740000	Miscellaneous Current Assets
1740001	Misc Deferred Charges

1740002	Misc Deferred Sega Charges
1740003	Deferred Sce&g Charges Correct
1740004	Deferred Psnc Charges Correct
1740005	Deferred Transaction Fees
1740006	Agency Acct- Chas Ctr Omni
1740007	Columbia Hca Call Option
1740008	Greenwood Call Option No-notic
1740009	Def Debit Guc Option Mtm
1740200	Record Imbalances
1741010	Clinton Newberry No Notice Cal
1750000	Derivative Instruments - Ncemc
1750001	Derivative Instr Asts-pm Swaps
1750002	Der Assets 50m Ubs 232
1750003	Der Assets Mizuho 100m 225
1750004	Der Assets 100m Tdb 221
1750005	Der Assets 50m U S Bank 219
1750006	Der Assets 100m Jpm 230
1750007	Der Assets 50m Jpm 220
1750008	Der Assets 100m Wf 226
1750009	Der Assets 50m U S Bank 228
1750010	Der Assets Jpm #242
1750011	Der Assets Mizuho #243
1750012	Der Assets Ubs #244
1750013	Der Assets Wells Fargo #245
1750014	Der Assets Td Bank #246
1750015	Der Assets U S Bank #247
1750016	Der Assets - Morgan Stanley #2
1750017	Der Assets - Wells Fargo #257
1750018	Der Assets Bank Of America #25
1750019	Der Assets #260 Mufg Union Ban
1750020	Der Assets #261 Td Bank
1750021	Der Assets #262 Rbc
1750022	Der Assets #263 Cs
1750023	Der Assets #265 Ms
1750024	Der Assets #266 B Of A
1760000	Scpc Gas Hedging Losses - Net
1760001	Psnc Hedges - Asset
1760002	Hedges Market Value
1760003	Other Current Assets
1760004	Hedges Market Value
1760005	Otc Swaps

1760006	2007 Swap
1760007	Dia Hedges-36.4m Fss
1760008	Dia Hedges-150m Fss
1760009	Derivative Ins - 20m Swap
1760010	Der Asset - 100m Cs
1760011	Der Asset - 100m Jpm
1760012	Der Asset 75m Boa Swap
1760013	Der Asset 75m Db Swap
1760014	Semi-1330 Lady St Deferred Ren
1760015	Sega - Aiken Lease
1760059	Derivatve Asset-2010 Boa Swap
1760060	Derivative Asset 300m Fss
1760061	Der Asset 250m Fv Hedge
1760067	Deriv Asset-2010 Wachovia Swap
1760068	Der Asset 80m Swap Ubs
1760069	Der Asset 80m Swap Mizuho
1760070	Der Asset-90m Ubs
1760071	Der Asset - 80m Wf
1760072	Der Asset - 80m Boa
1760073	Der Asset - 90m Swap Mizuho
1760074	Der Asset - 80m Ms
1760075	Der Asset - 80m Db
1760199	Derivative Instrument Assets
1760301	Broker Option Premium Wires
1760302	Otc Swap Settlement Current
1760303	Unrealized G L Swap Short-term
1760304	Unrealized Gl Options St
1760305	Unrealized Gl Mtm Contracts St
1760306	Basis Swaps - Short Term Asset
1760307	Cust Contr-short Term Asset
1810001	Unamort Debt Exp-berk Co 2003
1810002	Debt Exp $39.480m 4pct Bonds
1810003	Unamt Dbt Exp-prud 20yr 2 1 24
1810004	Unamt Dbt Exp-genco 2008 Note
1810005	Unamt Dbt Exp-gn Ind Rev Bonds
1810006	Dept Exp $14.735m 3.625pct Bon
1810007	Unam Debt Exp 400m 4 6 6152043
1810008	Unam Debt Exp 5.1% 500m Bonds

1810100	Unamortized Debt Discnt & Exp
1810101	Unamort Debt Exp 71/8% 2014
1810102	Unamort Debt Exp 20yr 12/31/11
1810103	Unam Debt Exp 6 7% 2/1/2011
1810104	Unam Dbt Exp 6.625% Due 2/1/32
1810105	Dbt Exp 100m Mtn 8/15/03
1810106	Un Debt Exp 5 8% - 1 15 33
1810107	Unam Debt Exp 250m Mtn Due 4-1
1810108	Dbt Exp 6 875% 300m 5 15 11
1810109	Unam Debt Exp 15 1/2% ??? Date
1810110	Unam Debt Exp 10% 2004
1810111	Unam Debt Exp 8.75% 2012
1810112	Unam Debt Exp 6.99% 2026
1810113	Unam Debt Exp 7.45% 2026
1810114	Unam Debt Exp 6.625% 2011
1810115	Unamort Debt Exp 6% 1997
1810116	Unam Debt Exp 6 1/2% 1998
1810117	Un Dbt Ex 100m 5 25 Bnd3 1 35
1810118	Unam Dbt Exp 100m Mtn 3 1 08
1810119	Unam Debt Exp 250m 6 05% Bonds
1810120	Unam Debt Exp 7 1/4% 2002
1810121	Un Debt Exp 6 5 Series Due
1810122	Unam Penalty Exp 6 99% 2026
1810123	Unam Penalty Exp 7 45% 2026
1810124	Unam Debt Exp 6 25% Due 2036
1810125	Unam Debt Exp - 35m Irb
1810127	Unam Debt Exp 5.95% 2003
1810129	Unamrt Dbt Exp $56910000 @ 5.2
1810130	Unamort Debt $29150000 @ 5.45%
1810131	Un Debt Exp 4.20% Bonds
1810132	Unam Penalty Exp 6 99% 2026
1810133	Unam Penalty Exp 7 45% 2026
1810134	Unam Penalty Exp 6 625% 2011
1810135	Un Dbt Exp-2009 Hybrid Notes
1810136	Un Dbt Exp - 2009 Fmb
1810137	Unam Debt Exp 6 54 2020
1810138	Unam Debt Exp 4 59 2021
1810139	Unam Debt Exp Fairfld Co 1984
1810140	Unam Debt Exp 30 Mill Orgbrg
1810141	Unam Debt Exp 4 13% Due 2046

1810142	Unam Debt Exp 4.18% Due 2047
1810143	Unam Dbt Exp Rchld Co Pol Ctrl
1810144	Unam Debt Exp Fairfld Co 1986
1810145	Unam Dbt Exp $250m Fmb Due 2-1
1810146	Unam Dbt Exp Col Dorch Bnd-'87
1810149	Unam Debt Exp 9% 7/15/2006
1810150	Unam Debt Exp 8 7/8% Bond
1810151	Unam Debt Exp 7 5/8% 2023
1810152	Unam Debt Exp 6% 6/15/00
1810153	Unam Debt Exp 7 1/8% 6/15/13
1810154	Unam Debt Exp 7 1/2% 6/15/23
1810155	Unam Debt Exp 6 1/4% 12/15/03
1810156	Unam Debt Exp 7.70% 2004
1810157	Unam Debt Exp 7 5/8% 2025
1810158	Unam Debt Exp 7.55% 2027
1810159	Unamt Dbt Exp 6 1/8% 3/1/09
1810160	Unam Debt Exp 400m 6 59%
1810161	Unam Dbt Exp 5 3% Due 5 15 33
1810162	Unam Debt Exp 40mm Due 6 1 34
1810163	Un Dbt Exp 250m 5 25% 11 1 18
1810164	200m Mtn Due 11 15 06
1810165	Unam Dbt Exp $300m 4.5% Due 6/
1810167	Unam Debt Exp 4.1% Due 6/15/46
1810177	Unam Debt Exp 202m
1810178	Un Dbt Exp 300mtn 7 15 2002
1810179	Una Dbt Exp 7 50% 6 15 2005
1810180	Unam Debt Exp Med 7/1/98
1810181	Unam Debt Exp Med 7/3/00
1810182	Unam Debt Exp Med 7/1/03
1810183	Unam Debt Exp 25m 2007
1810184	Unam Debt Exp 30m 1999
1810185	Unam Debt Exp 7yr Notes
1810186	Unamort Debt Exp 60m Mtn
1810187	Unamort Debt Exp 80m
1810188	Unamrt Dbt Exp Mtn Due 2003
1810189	Unamrt Dbt Exp Mtn Due 2008
1810190	Unamrt Dbt Exp Mtn 6 30 03
1810191	Unamort Dbt Exp 50 Mil Mtn
1810192	Unamort Dbt Expense Mtn Due
1810193	Unamt Dbt Exp 150 Mtn 7 00

1810194	Unamrt Dbt Exp $250m 6.25% Mtn
1810195	Unam Dbt Exp 150m Var Rate Nte
1810196	Unamrt Dbt Exp 300m
1810197	Unam Debt Exp 30m Fmb 3 22
1810198	Unamort Debt Exp 250m
1810199	Unamort Debt Exp 250m
1822100	Unrecovered Plant Parr
1822101	Unrecov Plnt Contra Parr
1822102	Unrecov Plant Hagood
1822103	Unrecov Plnt Contra Hagood
1822104	Unrecov Plnt Defective Stm Gen
1822105	Unrcvrd Plt Dfctv Stm Gen Cont
1822106	Unrecovered Plant - Urq Unit 3
1822107	Unrecovered Plant - Mcmeekin
1822108	Unrecovered Plant - Canadys 2
1822200	Demolition - Parr Steam Plant
1822201	Demolitn-contra-parr Steam Plt
1822202	Demolitn-hagood Steam Plant
1822203	Demolitn-contra-hagood Stm Plt
1822204	Unrec Plt Prop Air Facil Cola
1822205	Contra Prop Air Facil Cola
1822206	Unrec Plt Prop Air Facil Chas
1822207	Contra Prop Air Facil Chas
1822208	Unrecovered Plant - Can Unit 1
1822209	Unrecov Plnt - New Nuclear Gen
1823000	Reg Asset St Adit Elec
1823001	Reg Asset St Adit Gas
1823002	Reg Asset Fed Adit Elec
1823003	Reg Asset Fed Adit Gas
1823004	Reg Asst Fuel Claus Undrcllctn
1823005	Orangeburg Fuel Undercollectio
1823006	Reg Asset Miscellaneous
1823007	Reg Asset Pga Undercollection
1823008	Reg Asset St Adit Coach
1823009	Reg Asset Fed Adit Coach
1823010	Rg Asset Fuel Clause Contra
1823011	Reg Asset Psnc Def Gas Costs
1823012	Reg Asset Psnc Y2k
1823013	Reg Asset Psnc Def Gas Sales

1823014	Reg Asset Misc Psnc Ncuc Matte
1823015	Reg Asset Psnc 1997 Rate Case
1823016	City Of Charleston - Franchise
1823017	Charleston - Franchise-contra
1823018	City Of Columbia - Franchise
1823019	Columbia - Franchise - Contra
1823020	Reg Asset Estimated L&u True U
1823021	Deferred Hedge Costs
1823022	Reg Asst Recovery Of Fuel Cost
1823023	Regulatory Asset Calhounpk Mgp
1823024	Reg Asset- Gridsouth Rto
1823025	Reg Asset Pipeline Integ Costs
1823026	Reg Asset Major Maint Accrual
1823027	Reg Asset Pga Unbilled Contra
1823028	Reg Asset Elec Fuel - Unbilled
1823029	Hedges - Asset
1823030	Hedges - Contra Account
1823031	Reg Asset Res Commodity Under
1823032	Reg Asset Comm Commodity Under
1823033	Reg Asset Ind Commodity Under
1823034	Reg Asset Res Demand Under
1823035	Reg Asset Comm Demand Under
1823036	Reg Asset Ind Demand Under
1823037	Other Reg Assets - 06 Lock
1823038	Reg Asset Unrecov Ferc Sttlmnt
1823039	Hedges-asset
1823040	Reg Asset Work Comp Ibnr
1823041	Reg Asset Reagent Under Colect
1823042	Reg Asset - 2007 Fss
1823043	Other Reg Assets-36.4m Fss
1823044	Other Reg Assets-150m Fss
1823045	Reg Asset Pipeline Integ Amort
1823046	Elec Crew Qtr Remediation
1823047	Hagood Remedia - Exxon Mobile
1823048	2010 $25mil Elec Wthr Adj
1823049	2012 Incremental Rate Case Exp
1823050	Reg Asset Def Residential

1823051	Interest Income Mjm Psc Accrl
1823052	Reg Asset - Environmental Psi
1823053	Gas Wna Cap-winter 2012
1823054	Eiz Tax Credit - Overage
1823055	Reg Asset Def Vcs Up-flow Mod
1823056	Reg Asst Recover Capacity Purc
1823057	Incremental Rate Case Expenses
1823058	Reg Asset - Retire Canadys #1
1823059	Elec Pension Rider Underrcvry
1823060	Reg Asset Residential Cut
1823061	Reg Asset Commercial Cut
1823062	Other Reg Asset - 150m Swap
1823063	Reg Asset So2 Emission Allowan
1823064	Reg Asset-defer Capacity Purch
1823065	Reg Asset-fukushima-vcs
1823066	Reg Asset - Defer Capacity Pur
1823067	Res Dsm Lost Revenue Adjustmnt
1823068	Com And Ind Dsm Lost Revenue A
1823069	Reg Asset-def Cap-2014-2016-so
1823070	Reg Asset-def Cap-2014-19 Colu
1823071	Reg Asset Pen Exp Curtailment
1823072	Reg Asset Nnd Carrying Costs
1823073	Reg Asset - Cip5
1823074	Nucl Refueling Outage Cost
1823075	Reg Asset-cyber Security Compl
1823076	Reg Asset - Ubs #252
1823077	Reg Asset - Boa #249
1823078	Reg Asset-morgan Stanley #251
1823079	Reg Asset - Boa - Swap #250
1823080	Reg Asset - Us Bank Swap #254
1823081	Reg Asset - Union Bank Swap #2
1823082	Reg Asset-morgan Stanley-reg A
1823083	Gas Wna Cap -winter 2015
1823084	Gas Wna Cap -winter 2016
1823085	Reg Asset-cyber Secur Depr Car
1823086	Reg Asset $75mm Due 6/1/64
1823087	Reg Asset $425mm Due 6/15/46
1823088	Reg Asset Union Bank #260

1823089	Reg Asset - Tdb #261
1823090	Reg Asset Rbc #262
1823091	Reg Asset - Credit Suisse #263
1823092	Gas Wna Cap- Winter 2017
1823093	Reg Asset Nnd Fas 109 Fed Adit
1823094	Reg Asset Nnd Fas 109 St Adit
1823095	Reg Asset Nnd 41/199 (pilot)
1823096	Reg Asset Nnd Acct Fees/intere
1823097	Reg Asset-imt(int Mgmt Trkr)
1823098	Reg Asset-dimp(dist Int Mgmt)
1823099	Reg Asset - Trans Nnd Depn
1823100	Reg Asset-dimp Amortz
1823101	Reg Asst Def Start Up Cost Vcs
1823102	Reg Asset Roto Shot Peen Vcs
1823103	Reg Asset Wesths Litigation
1823104	Reg Asset Doe D And D Fund
1823105	Reg Asset - Decom Aro
1823106	Def Aro Acretion And Arc Depr
1823107	Def Econ Grant - Dixie Narco
1823108	Def Econ Grant - Michelin
1823109	Def Econ Grant-bf Phase 1
1823110	Def Econ Grant-bf Phase 2
1823111	Def Econ Grant-bf Phase 3
1823112	R & D Grant - Clemson
1823113	Def Econ Grant - Michelin 2
1823114	Def Econ Grant - Nexans
1823115	Def Econ Grant - Koyo Corp
1823116	Def Econ Grant - Boeing/chas C
1823117	Def Econ Grant - Mercedes/chas
1823118	Def Econ Grant - Fairfield Meg
1823119	Def Econ Grant - Project Giant
1823120	Def Econ Grant-kronotex
1823130	Reg Asset - Cut Rate 101
1823131	Reg Asset - Cut Rate 102
1823132	Reg Asset - Cut Rate 125
1823133	Reg Asset - Cut Rate 127
1823134	Reg Asset - Cut Rate 140
1823189	Winnsboro Fuel Undercollected
1823200	Reg Asset Dem Side Mgt Costs
1823205	Deferred Storm Damage Costs
1823210	Reg Asset Gwh 2000
1823211	Reg Asset Gwh 1993
1823212	Reg Asset Gwh 1994
1823213	Reg Asset Gwh 1995

1823214	Reg Asset Gwh 1996
1823215	Reg Asset Gwh - 1997
1823216	Reg Asset Gwh 1998
1823217	Reg Asset Gwh 1999
1823220	Reg Asset Gwh Rebates
1823225	Reg Asset Gwh Empl Referral
1823226	Reg Asset Gwh Rbt Rec Sonat
1823230	Reg Asset Gwh 2000
1823231	Reg Asset Gwh 2001
1823232	Reg Asset Gwh 2002
1823233	Reg Asset Gwh 2003
1823234	Reg Asset Gwh 2004
1823235	Reg Asset Gwh 2005
1823236	Reg Asset Gwh 2006
1823237	Reg Asset Gwh 2007
1823238	Reg Asset Gwh 2008
1823239	Reg Asset Gwh 2009
1823240	Reg Asset Gwh 2010
1823241	Reg Asset Gwh 2011
1823242	Reg Asset Gwh 2012
1823243	Reg Asset Gwh 2013
1823244	Reg Asset Gwh 2014
1823245	Reg Asset Gwh 2015
1823246	Reg Asset Gwh 2016
1823247	Reg Asset Gwh 2017
1823255	Res Water Heaters
1823256	Res Appliance Recycling
1823257	Reserved For Demand Side Mgnt
1823258	Reserved For Demand Side Mgnt
1823259	Res Limited Income
1823260	Dsm Admin
1823261	Res Benchmarking
1823262	Res In-home Display
1823263	Res Energy Check Up
1823264	Res Estar Light And Appliance
1823265	Res New Hvac And Duct Work
1823266	Res Existing Hvac - Tune-up
1823267	Res Energy Star New Homes
1823268	Res Home Perf Audit
1823269	Res Dsm Accumulated Amort
1823271	C & I Energy Wise For Business
1823272	Com And Ind Custom
1823273	Small Business Direct Install
1823274	Reserved For Demand Side Mgnt

1823275	Reserved For Demand Side Mgnt
1823276	Reserved For Demand Side Mgnt
1823278	Reserved For Demand Side Mgnt
1823279	Com And Ind Dsm Accumultd Amrt
1823280	Res Dsm Accum Amort
1823281	Com Ind Dsm Accum Amort
1823282	Res Dsm Carrying Costs
1823283	Com Ind Dsm Carrying Costs
1823300	Reg Asset Oer Retirements
1823301	Reg Asset Supp Exec Retirement
1823302	Reg Asset Nuc Wo99 Retirement
1823303	Reg Asset Oer Only Retirements
1823304	Reg Asset Ubs #240
1823305	Reg Asset U S Bank #239
1823306	Reg Asset Mizuho #238
1823307	Reg Asset Td Bank #241
1823310	Reg Asset Severance & Erip Pay
1823315	Reg Asset - Ltd
1823316	Reg Asset - Ltd-gas
1823320	Reg Asset Nuc W099 Severance
1823350	Reg Asset-t Lock 6 625 Due 2 1
1823351	Reg Asset-t-lock 6 80 Due 1 15
1823352	Reg Asset-t-lock 6 25 Due 7 1
1823353	Reg Asset 5 30 T Lock Due 5 15
1823354	Reg Asset T Lock 5 25 Due 11 1
1823355	Reg Asset-t Lock 5 25 Due 3 1
1823356	Reg Asset-swap 6 05 Due1 15 38
1823357	Reg Asset-lock 6 05 Due 1 15 2
1823358	Reg Asset - 150m Fmb
1823359	Reg Asset 125m Swap Boa
1823360	Reg Asset 125m Swap Wf
1823361	Reg Asset 100m Csfb
1823362	Reg Asset 75m Boa
1823363	Reg Asset 75m Wells Fargo
1823364	Reg Asset 35m Boa Sifma Swap
1823365	Reg Asset 90m Csfb
1823366	Reg Asset U S Bank #228
1823367	Reg Asset W/f #226
1823368	Reg Asset Jpm #220
1823369	Reg Asset Jpm #230

1823370	Reg Asset U S Bank #219
1823371	Reg Asset Td Bank #221
1823372	Reg Asset Mizuho #225
1823373	Reg Asset Ubs #232
1823374	Reg Asset Union Bank #233
1823375	Reg Asset Ubs #231
1823376	Reg Asset Cs #218
1823377	Reg Asset Cs #229
1823378	Reg Asset W/f #217
1823379	Reg Asset Ms #227
1823380	Reg Asset Boa #222
1823381	Reg Asset #234
1823382	Reg Asset - New Sifma
1823383	Reg Asset Us Bank #236
1823384	Reg Asset Ubs #237
1823385	Der/net - O&m Incremental
1823386	Reg Asset-jpm-#242
1823387	Reg Asset-mizuho-#243
1823388	Reg Asset-ubs-#244
1823389	Reg Asset-wf-#245
1823390	Reg Asset-$500mm Debt Due 6-1-
1823391	Der Avoided Costs
1823392	Der Capital - Incremental
1823393	Reg Asset Td Bank #246
1823394	Reg Asset U S Bank #247
1823395	Reg Asset M Stanley #256
1823396	Reg Asset Wf #257
1823397	Reg Asset Boa #258
1823398	Der Incremental Nem Costs Def
1823400	Reg Asset Env Remed Cur Vintge
1823401	Reg Asst Mgp Env Remd Cur Vntg
1823402	Reg Asst Env Remed Future Vntg
1823403	Reg Asst Mgp Env Rem Ftr Vntg
1823404	Reg Asst Elec Env Carryg Costs
1823405	Reg Asst Aegis Claim Env Lblts
1823406	Reg Asset Mgp Chas Settlement
1823407	Reg Asset Freight Buy Down
1823408	Reg Asset Psnc Env Compl
1823409	Regulatory Asset Calhounpk Mgp
1823410	Regulatory Aseet- Propane Plts

1823411	Reg Asset - Gas Sfas 158 Adj
1823412	Reg Asset Elec Sfas 158 Adj
1823413	Frq Reg Asset Reclass From 254
1823414	Reg Asset - Elec Fas 87 Deferr
1823415	Reg Asset - Gas Fas 87 Deferra
1823416	Reg Asset - Pension Curtailmen
1823417	Reg Asset-reg Fee Deferral
1823481	Reg Asst Rate Case 2006
1823483	Reg Asset Rate Case 2008
1823484	Reg Asset Rate Case 2016
1823500	Reg Asset Cust Aw Prg Vint-200
1823501	Reg Asset Cust Aw Pro Vntg-200
1823502	Reg Asst Cust Aw Pro Vntg-2009
1823503	Reg Asst Cust Aw Pro Vntg 2010
1823504	Reg Asst Cust Aw Pro Vntg 2011
1823505	Reg Asset Cust Aw Pro Vntg 201
1823506	Reg Asset Cust Aw Pro Vntg 201
1823507	Reg Asst Cust Aw Pro Vntg 2014
1823508	Reg Asst Cust Aw Pro Vntg 2015
1823600	Reg Asset-poll Control-cope Sc
1823601	Reg Asset-poll Cntrl-wms Scrbr
1823602	Reg Asset-poll Cntrl-wat Scrbr
1823603	Regulatory Asset-lidar Surveys
1823604	Jad Contract Termination (coal
1823605	Reg Asset-ferc Aca Charges
1823700	Gas Pipeline Integrity
1823800	Reg Asset Tax Rate Chg Nol
1830000	Prelim Survey & Investgtn-misc
1830001	Psi Wt2 Blr Feed Pump Turb Rtr
1830002	Psi Future Unit Bayer
1830003	Psi Saluda Turb Venting
1830004	Psi Williams Ict
1830005	Psi Mcm Ash Land Fill Study
1830006	Psi Mcm Low Nox Burners
1830007	Psi Cdys123 Low Nox Basln Test
1830008	Psi Fps Elec Control Rehab
1830009	Psi Nuga Study Const
1830010	Psi Urq Precip Air Flow Study
1830011	Psi Wms Impact Load Study
1830012	Psi Brnchvll Coal Transld Facl
1830013	Psi Shkspr 2d Storm Water Impr
1830014	Psi Circulate Wat Measurement
1830015	Psi Future Units Granitville
1830016	Psi Parr Dam Modification

1830017	Psi Wlms Turbine Heat Recovery
1830018	Psi Urq Env Cap Projects
1830019	Psi Sal Dam Stab Study
1830020	Psi Prelim Engr Vcs
1830021	Psi Canadys No3 Upgrade
1830022	Psi Pwr Program Tanker Upgrade
1830023	Psi-wtr Filter Water Syst Pipe
1830024	Psi Wateree Ash Land Fill
1830025	Psi Gen Protect Williams
1830026	Psi Urq Ash Land Fill Study
1830027	Psi Carbon Burn Out Engr Study
1830028	Psi Cndys Particulate Control
1830029	Psi Huron Project
1830030	Psi Urquhart1 2&3 Nox Study
1830031	Psi W'ee Coal Handling
1830032	Wateree 1 Cooling Tower
1830033	Wateree Low Temp Reheater
1830034	Urq2 Waste Fuel Firing
1830035	Vcs Plant Life Extension
1830036	Mcmeekin Coal Mill Upgrade
1830037	Srs At1 Cable Replacement
1830038	New Generation Options
1830039	Mcm Nox Test And Optimizati
1830040	Cope Nox Test And Optimizat
1830041	Urq Nox Test And Optimizati
1830042	Mcmeek Storm Drainage Study
1830043	Wa1 High Temp Sh Inlet Head
1830044	Wateree Boat Ramp
1830045	Old Westvaco Turbine Genera
1830046	Wateree 1 And 2 Ash Silo
1830047	Wat Dyn Clssfrs And Cl Pipe
1830048	Wa 1 Sootblower Replacement
1830049	Psi Urq Septic System
1830050	Reserved For Sue Morris
1830051	Wat Sanitary Sewer Upgrade
1830052	Constr Svcs Equip Wash Pad
1830053	Synfuel Project - Wateree
1830054	2004 Gas Turbine Gen Proj
1830055	Wateree 1 & 2 Baghouse
1830056	Mcmeekin Sep Overfire Air
1830057	Williams Scr
1830058	Utah 5 Coaltech 1lp
1830059	Wat 1 And 2 Scrs
1830060	Wat Unit 1 Improvements
1830061	Wat 1&2 Cable Trench Study

1830062	Wateree Coal Handling Upgrade
1830063	Wateree Lab Upgrade
1830064	Psi Canadys No 3 Cooling Tower
1830065	Psi Fossil & Hydro Office Bldg
1830066	Nox Ozone Transport Study
1830067	Wat Units 1 & 2 Esp Study
1830068	Cope Baghouse Corrosion Rem
1830069	City Of Fayetteville Nc
1830070	Synfuel Project Canadys
1830071	Sc Lake Murray Prop Transf
1830072	Mcmeekin Sofa Sncr
1830073	Jasper Power Project
1830074	Cope Unit 2
1830075	Wateree Main Steam
1830076	Wat Cc Cooling Study
1830077	Wlms Boiler Study
1830078	Wlms Gen Rewind
1830079	Wat Crusher House Exhaust
1830080	Srs Boiler Upgrade
1830081	Cdys Wtr Wall Tube Rpl
1830082	Env Air Quality Imp Prj
1830083	Wat Load & Coordination
1830084	Warning System Study
1830085	Vanadium-redox Study
1830086	Phoenix/nasa Research Study
1830087	Wat Ash Landfill Study
1830088	Srs Controls
1830089	Canadys #3 Life Cycle Investig
1830090	Cdy Makeup Water Test Well
1830091	Cope Soot Blowing Pipe Redesig
1830092	Cdy Slurry Wall Evaluation
1830093	Wat Ash Land Fill Study
1830094	Srs D-area Land Fill Study
1830095	Cdy #3 Ms & Hrh Hanger Design
1830096	Mcm Steam Seal Regulator Rpl
1830097	Wlms Fsss Study
1830098	Modify Wateree Coal Bunkers
1830099	Psi Automated Meter Reading
1830100	Psi Ist Storage Solution
1830101	Cope Nox Tech Evaluation
1830102	Canadys 3 Lnb Replacement
1830103	Mcm Private Car Side Track
1830104	Regulatory Compliance Studies
1830105	Park Site 1 - Highway Mod

1830106	Urquhart Unit 3 Sofa System
1830107	Srs Hanger Replacement
1830108	Kempson Bridge Recreation Area
1830109	Plant Loto - Grounding Project
1830110	Wt Chem Storage And Unloading
1830111	Cdy 3 Pressure Part Investigat
1830112	Saluda Dam Upstream Rip Rap
1830113	Cope Main Condenser Penetratio
1830114	Fish Entrainment Studies
1830115	Wat Unit 2 High Pressure Feedw
1830116	Can-wdpf Control Extensions
1830117	Saluda Spillway Seismic Rem
1830118	So2 Reduction Study
1830119	Mcm Unit 2 #6and7 Feedwater He
1830120	Cdy 003 Outfall Elimination Pr
1830121	Williams Boiler Flow Study
1830122	Cope Baghouse Ductwork Remed
1830123	Cope Boiler Reheat Model Devel
1830124	Cope Critical Steam Piping
1830125	Wat Unit 1 Bfp Controls
1830126	Wat Unit 2 Bfp Controls
1830127	Wat 1 Turbine Control System
1830128	2 Turbine Control System
1830129	01 Gen Hydrogen Cooling Panel
1830130	Wat 02 Gen Hydrogen Cooling Pa
1830131	Mcmeekin Ash System
1830132	Canadys Landfill Siting Study
1830133	Mcm Coal Handling Unloading
1830134	New Generation Site Location
1830135	New Gen-feasibility Study-2005
1830136	New Nu Generation Study
1830137	New Nu Generation Study-nonshr
1830138	Cope Scr Studies And Scoping
1830139	Mcm Waste Water Treatment
1830140	Psi- Vcs Information Center
1830141	Canadys #1 Electrocore Project
1830142	Williams Barge Unloading

1830143	Canadys Ash Pond Road
1830144	New Gen-system Impact-2005
1830145	New Gen-facility Study-2005
1830146	Ffp Monticello Reservoir Op Rg
1830147	Urq L6000 Turbine Remote Strt
1830148	Wateree Cbo Upgrade
1830149	Cdy 3 Dry Ash Collection Proj
1830150	Williams Wet Scrubbers Proj
1830151	Wateree Wet Scrubbers Proj
1830152	Cope Landfill Cell 3
1830153	Mercury Monitoring Technology
1830154	Zolo Technology System
1830155	Williams Slag Screen Problem
1830156	Monticello Dam Geophysical Sur
1830157	Parr Hydrographic And Island S
1830158	Canadys Coal Dumper Fac Exp St
1830159	Mcm-steam And Reheat Pipe Hang
1830160	Wlms Landfill Arsenic Treatmen
1830161	Cope Closed Cycle Study
1830162	Transm Envir Nrc Col Vcs Unit3
1830163	Wateree - Production Wells
1830164	Mcmeekin Coal Unloading Study
1830165	Canadys Coal Unloading Study
1830166	Ge Zonal Monitoring System
1830167	Transm Envir Nrc Col Vcs Unit2
1830168	Mcmeekin - Star Heat Recovery
1830169	Williams - 316a Revalidation
1830170	Cope Production Well Study
1830171	New Nu Gen Impact-srs
1830172	New Nu Gen Impact-saluda
1830173	New Nu Gen Impact-cope
1830174	New Nu Gen Impact-fairfield
1830175	Landfill Compl - Waste Reclass
1830176	Canadys New Ash Landfill
1830177	Cdys-electrostatic Precipitato
1830178	Wateree - So3 Injection System
1830179	Williams - Cooling Tower Study
1830180	Fish Entrainment Studies
1830181	Econimizer Bypass System
1830182	Psi Columbia To Eastover-cgt
1830183	Transco To Charleston-cgt

1830184	Fgd Redundant Limestone Feasib
1830185	Electronic Field Data Col
1830186	Psi Vcs1 Switchyard Add Capaci
1830187	Meeting St Replacement Sub Sit
1830188	Psi Efdc Phase Ii
1830189	Fish Entrailment Study 316b
1830494	Cpp Mou
1830499	Open Access Intrastate
1830516	Hwys 15 And 10-darlington
1830518	G-8 G-2 Gas Producers Turbines
1830519	Road Improvements-old Cherokee
1830520	Open Season Evaluation
1830521	Psi - Bethune Rebuild
1830522	Hartsville Town Border Rebuild
1830523	Psi - Lidar Surveys
1830524	Calhoun/bull St Substation
1832000	Psi-data Center Evaluation
1832001	Psi Transco To Charleston-dill
1832002	Heath Springs - 16 Lin Aia
1832003	Psi Transco To Charleston-cgt
1832004	Psi Transco To Dorchester(comp
1832005	Fossil Hydro Study
1838494	Psi Carolinas Pipeline Proj
1838499	Open Access Intrastate
1838516	Hwys 15 And 10-darlington
1838518	G-8 G-2 Gas Producers Turbines
1838519	Road Improvements-old Cherokee
1838520	Open Season Evaluation
1838521	Psi - Bethune Rebuild
1838522	Hartsville Town Border Rebuild
1840000	Clearing Other
1840001	Clr Rubber Goods
1840002	Clr Gas For Elec Gener Other
1840003	Clr Mobile Home Hookup
1840004	Clr Elec Water Works
1840005	Clr Psnc Small Tools
1840006	Clr Copier Paper
1840007	Clr Pers Airfare Reimbursement
1840008	Clr Kerp A And G Salaries
1840009	Clr Home Ener Ck Program Loans

1840010	Clr Oer Severance Pay
1840011	Clr Fractional Shares
1840012	Clr Scpsa Invoices Scfc
1840013	Clr Adp Subsidiary Payroll
1840014	Clr Hvac Financing
1840015	Clr Brand Equity
1840016	Clr Cust Ar Payments
1840017	Clr Cust Ar Liheap Payments
1840018	Clr Cis Cash Account
1840019	Clr Dot And Drug Testing
1840020	Clr Misc Empl Deductions
1840021	Clr Procure Credit Cards
1840022	Clr Gatu Financing
1840023	Clr Emergency Repair
1840024	Clr Food Service Financing
1840025	Clr Elect Appliance Financg
1840026	Cis Invalid Acct Balance
1840027	Clr Short Term Disability
1840028	Clearing Duct Sys & Iaq Fin
1840029	Clr Psnc Cis Adjustments
1840030	Clearing Acct For Deadhead Exp
1840031	Clearing-sceg
1840040	Clearing Account-dominion
1840050	Clear Gas Supply
1840051	Rg Clearing
1840059	Clearing-airplane 2 Expenses
1840074	Clearing-airplane 4 Exp N974sc
1840075	Clearing-airplane 5 Exp N975sc
1840078	Clearing-medical Mobile Expens
1840079	Clearing-airplane 3 Expenses
1840080	Clr Nucl Aro Accretion-vcs1
1840100	Clr Sc Alloc To Nu Capital
1840122	Ar Transfer
1840125	Cons Billing Transfers
1840207	Clearing - Trailers
1840208	Clearing-power Operated Equip
1840209	Clr Vms Charges Wo Dist
1840210	Clr Transportation Exp
1840211	Clr Production Expenses
1840212	Clr Fac Pln Construction Dept
1840213	Clr Recycled Oil
1840214	Clr Water Environmental Exp
1840215	Clr Air Environmental Exp
1840216	Clr Central Lab Steam Analy

1840217	Clr Central Lab Fuel Analys
1840218	Clr Construction Equipment
1840219	Clr Research Prk Lease Chrgbck
1840220	Clr Payroll
1840229	Payroll Processing Exception
1840230	Clr Telephone Charges
1840239	Clr Offset Teleph Chargeback
1840240	Clr Office Supplies
1840241	Clr-sales & Use Tax Payments
1840245	Employee Airline Travel
1840247	Pager Chargebacks
1840250	Clr Storeroom Sales
1840260	Clr Print Dept Costs
1840270	Clr Postage
1840280	Clr Isd Training
1840281	Pc Leasing Costs
1840282	Clr Isd Charges
1840289	Clr Offset Computr Chargebacks
1840290	Clr Pal Ctr Mgt And Maint Exp
1840291	Clr Pal Ctr Mgt And Maint Sceg
1840292	Clr Pal Ctr Security Sceg
1840293	Clr Facility Maintenance
1840400	Clr Checking
1840401	Clr Check Ramsey Grove
1840402	Clr Check Electric Service
1840403	Clr Check Test Lab
1840404	Clr Check Land And Facilities
1840405	Trnsf Acct Bal Btw Cis Sys
1840406	Clr Check Secretarial Dept
1840407	Sega Retail Benefits Clearing
1840499	Clearing Bank Analysis
1840500	Clr Admin And Gen Salaries
1840501	Clr A And G Salary Hr Only
1840502	Clr A And G Salary Rates Only
1840503	Clr A&g Salary Facilities Only
1840504	Clr A&g Salary Security Only
1840505	Clr A And G Salary Apay Only
1840506	Clr A&g Salry Recrds Mgmt Only
1840507	Clr A&g Salary Microfilm Only
1840508	Clr A&g Salary Reproductn Only
1840511	Clr A And G Salary Mail Only
1840512	Clr A&g Salaries Claims Only
1840513	Clr A&g Slries Rev Protctn On
1840520	Clr Other Non Labor
1840521	Clr Oth Non Labor Hr Only

1840522	Clr Oth Non Labor Rates Only
1840523	Clr Oth Non Lbr Facilits Only
1840524	Clr Oth Non Labr Security Only
1840525	Clr Oth Non Labor Apay Only
1840526	Clr Oth Non Lbr Rcrd Mgmt Only
1840527	Clr Oth Non Lbr Microfilm Only
1840528	Clr Oth Non Labr Fbr Op Lse
1840531	Clr Non Labor Mail Svc Only
1840532	Clr Oth Non Labor Claims Only
1840533	Clr Oth Non Lbr Rev Prttn Only
1840540	Clr Out Serv Employed
1840541	Clr Out Serv Hr Only
1840552	Clr Reg Comm Exp Rates Only
1840560	Clr Misc General Expenses
1840561	Clr Misc Gen Exp Hr Only
1840570	Clr Rents
1840571	Clr Rents Hr Only
1840573	Clr Rents Facilities Only
1840580	Clr Maint General Plant
1840598	Nnd Severance
1840599	Cobra Benefits
1840600	Empl Ben Retirement
1840601	Empl Ben Group Insurance
1840602	Empl Ben Education And Tuition
1840603	Empl Ben Stk Purch Sav Prog
1840604	Empl Ben Long Term Disability
1840605	Empl Ben Empl Clubs Pi Island
1840606	Empl Ben Empl Clubs Sand Dunes
1840607	Empl Ben Empl Clubs Misty Lake
1840608	Empl Ben Empl Assist Program
1840609	Empl Ben Recreat Activities
1840610	Empl Ben Serv Awards
1840611	Empl Ben Credit Union Exp
1840612	Empl Ben Parking
1840613	Empl Ben Other
1840614	Empl Ben Wellness Programs
1840615	Empl Ben Flex Spending
1840616	Empl Ben Short Term Disabil
1840617	Emp Ben Pc Purchase Program
1840618	Empl Ben Grp Ins-res C
1840619	Prescription Drugs
1840620	Non Prescription Items
1840621	Other Pharmacy Costs

1840622	Resource Center Costs
1840623	Prescription Copays Receipts
1840624	Resource Center Receipts
1840625	Resource Ctr Costs-plan Part
1840626	Lt Disability - Supplemental
1840630	Estimated Pension And Benefits
1840631	Retirements Credits Or Charges
1840634	Medical Mobile Unit
1840635	Third Party Administrator Fees
1840638	Clear Employee Benefits
1840639	Clearance Pensions
1840640	Indir Payroll Vacation
1840641	Indir Payroll Holiday
1840642	Indir Payroll Sick Leave
1840643	Indir Payroll Military Duty
1840644	Indir Payroll Jury Duty
1840645	Indir Payroll Funeral
1840646	Indir Payroll Paid Time Off
1840649	Clear Indirect Payroll
1840650	Taxes Transfer Fica
1840651	Tax Transfer Fed Unemployment
1840652	Tax Transfer St Unemployment
1840659	Clear Taxes Transferred
1840699	Clearing Ltd Funds
1840901	Clear Ins Prem Pymt Svci
1840902	Clear Insurance Prem Pymt Sps
1840903	Clear Ins Prem Pymt Semi
1840904	Clear Insurance Prem Pymt West
1840905	Clear Insurance Prem Pymt Spr
1840906	Clear Insurance Prem Pymt Sdc
1840907	Clear Ins Prem Pymt Scpc
1840908	Clear Insurance Prem Pymt Spg
1840909	Clear Insurance Prem Pymt Sci
1840910	Clear Ins Prem Pymt Scfc
1840913	Clr Insurance Prem Pymt Sceg
1840914	Clr Insurance Prem Pymt Genco
1840915	Clear Ins Prem Pymt Sr
1840928	Clear Ins Prem Pymt Psnc
1840929	Clr-ins Prem Pymt-services Co
1842201	Ar Transfer
1842500	Cons Billing Transfers
1850000	Temporary Facilities

1860000	Misc Deferred Debits
1860001	Def Dr Chas Tran Transition
1860002	Def Dr Disp Of Contaminates
1860003	Def Dr Emp Ret Cks
1860004	Def Dr Accrl Ledger
1860005	Def Dr Theft Losses
1860006	Def Dr Inv Wo Prop Acct Dist
1860007	Def Dr Blnkt Po Wo Prop Dist
1860008	Def Dr Reel Deposits
1860009	Def Dr Claims
1860010	Misc Deferred Debits - Misc
1860011	Def Dr Right Of Way
1860012	Def Dr Itron Maint Agree
1860013	Def Dr Apay Amex And Clubs
1860014	Def Dr Div Escheated To St
1860015	Def Dr Trust Loans
1860016	Def Dr Aband Unclaim Prop
1860017	Def Dr Hardw And Softw Purch
1860018	Def Dr Emp Moving Exp
1860019	Def Dr Haitai Gwh Program
1860020	Ciac-cis Billing
1860021	Def Dr Airplane Exp
1860022	Def Dr Other Work In Prog
1860023	Def Dr Telephone Pole Rent
1860024	Misc Deferred Debits-cec
1860025	Take Or Pay Pyble-sceg Contra
1860026	Def Dr Companion Claims
1860027	Def Dr Caro Research Pk
1860028	Acc Amort-organizational Costs
1860029	C&t Incorporation Expenses
1860030	Acc Amort Of Preoperating Exp
1860031	Capitalized Preoper Expenses
1860032	Def Dr Gsx Settlement
1860033	Treas A For Cust Acctg
1860034	Cis System Balance
1860035	Land/site Preparation
1860036	Def Dr Walker Maint Agree
1860037	Def Franchise Agmt Muni Dev
1860038	Semi Billing Code
1860039	Peoplesoft And Powerplan Im
1860040	Defer Errors Wlkr Interface
1860041	Psnc Def Taxes Pension Inc
1860042	Def Dr Pal Ctr Lease Pmt
1860043	Warburg Swap Fair Value
1860044	Def Dr Psnc Pension
1860045	Def Dr Exp For Div Reinvest
1860046	Def Dr Exp For Empl Stk Plan

1860047	Inventory Adjustment
1860048	Misc Def Dr-swap-true Value
1860049	Deferred Debits - Sdc Losses
1860050	Def Dr Svc Co Chargebacks
1860051	Def Dr Sale Of Debentures
1860052	Def Dr Records Retention
1860053	Def Debit-chas Garage L-t Rec
1860054	Def Debit-chas Ug Trans Line
1860055	Def Dr-mgp Ins Settlement
1860056	Def Dr Psnc Scana Exp
1860057	Inventory Rec-amerada Hess
1860058	Def Dr Dep On Rented Prop
1860059	Def Dr Airplane 2 Exp
1860060	Def Dr Qtrly Trans Comm Costs
1860061	Def Dr Ncuc G5 Sub 300
1860062	Def Dr Ps Rounding Susp Acct
1860063	Oth Def Dr-2010 Cred Suisse Sw
1860064	Afudc Sc-debt
1860065	Afudc Eg-debt
1860066	Afudc Equity-eg
1860067	Chas Garage Accrued Interest
1860068	Deferred Debits-nu Pool St Int
1860069	Def Debit Cble Pole Attach Ren
1860070	Def Dr - Cope W O Issuance
1860071	Def Dr - Wateree W O Issuance
1860072	Def Dr - Canadys W O Issuance
1860073	Def Dr - Mcmeekin W O Issuance
1860074	Def Dr - Williams W O Issuance
1860075	Def Dr - Urquhart W O Issuance
1860076	Def Dr-hydro Turb W O Issuance
1860077	Deferred Debit-r&e Tax Credit
1860078	Jasper Work Order Issuance
1860079	Psnc W C Ibnr
1860080	Def Dr Wateree Stator Bars
1860081	Deferred Dr-jasper Ge Csa
1860082	Deferred Dr-scrubber Projects
1860083	Def Debit - 20m 2008 Swap
1860084	Oth Def Debits- 36 4m Fss
1860085	Def Dr Nu Inventory Wo
1860086	Def Debit - 2007 Swap
1860087	Def Dr - Notes Receivable
1860088	Def Dr Cap Lease Monroe Pipe
1860089	Deferred Debit Fh Inventory C
1860090	Def Dr - Ea Customer Purchase
1860091	Def Dr - Accum Amort Ea Cust P

1860092	Def Dr - Aiken Pre-paid Rent
1860093	Def Dr - Emc Non-compete Amend
1860094	Def Dr - Accum Amort Emc Non-c
1860095	Special Deposits - Falcons Sta
1860096	Deferred Debit - Urquhart Ge C
1860097	Defer Dr - Cyber Ark
1860098	Pal Gas
1860099	Lng Oba Gas
1860100	Deferred Dr Firm Trans Resv
1860101	Def Dr Pal Ctr
1860102	Def Dr Wachovia Lse Pal Ctr
1860103	Misc Def Debit Macro
1860104	Def Dr Direct Endow
1860105	Misc Def Dr M/s Entrpz
1860106	Def Dr Wlkr Mnt Agrmnt Accr
1860107	Def Dr Laurel Crest Retire
1860108	Def Dr Computer Associates
1860109	Computer Associates 2001
1860110	Misc Def Dbts Psnc It Inter
1860111	Misc Def Debit Embarc Tech
1860112	Misc Def Dr Levi Ray Shoup
1860113	Misc Def Debit Compuware
1860114	Misc Def Dr Network Assoc
1860115	Misc Def Dr Peoplesoft Trn
1860116	Misc Def Dr Carotek
1860117	Misc Def Dr - Ms Upgrade Adv
1860118	Misc Def Debit - Dimension Dat
1860119	Misc Def Dr Consulting Fees
1860120	Def Dr-discount Lost Peoplsoft
1860121	Misc Def Dr - Harvest
1860122	Def Dr Dsg Hw Maint
1860123	Def Dr Records Mgmnt
1860124	Def Dr Chicago Soft
1860125	Def Dr Websense
1860126	Def Debit Quest Soft
1860127	Def Dr Bmc Maintance
1860128	Psnc Workers Comp Reserve Def
1860129	Def Dr Syncsort
1860130	Misc Def Dr Princeton
1860131	Def Dr Sc Eiz Credit Federal
1860132	Def Dr Sc Eiz Credit State
1860133	Def Dr Shi Maint
1860134	Def Dr 5yr Commitment Fees
1860135	Def Dr Bea Systems

1860136	Def Dr Sirius Svcsuite
1860137	Def Deb - Lock - 2005
1860138	Def Dr Vmware Virtual
1860139	Def Dr Allen Systems
1860140	Gasman Rewrite
1860141	Def Dr Symantec
1860142	Def Dr Sirus Tape Sil
1860143	Def Dr - Neon
1860144	Def Dr Enterprise
1860145	Def Dr Ciphrtrst-iron
1860146	Def Dr Sms Wakeup
1860147	Def Dr - Sirius - Ibm 2066
1860148	Def Dr - Dell - F5
1860149	Sceg Workers Comp Reserve Def
1860150	Deferred Dr Firm Trans Resv
1860151	Deferred Dr - Google Appliance
1860152	Deferred Peoplesoft License
1860153	Def Dr - Dts Software
1860154	Defer Dr - Safeboot
1860155	Defer Dr - Packet Design
1860156	Def Dr-fees 3yr Agreement
1860157	Cip5 Regulatory Costs
1860158	Der Assets 35m Sifma Jpm 234
1860159	Der Assets-36 4m Swap
1860160	Oth Def Debits - 100m Swap Cs
1860161	Oth Def Debits - 100m Swap Jpm
1860162	Der Assets 100m Union Bank 233
1860163	Der Assets 50m Ubs 231
1860164	Der Assets 100m Cs 218
1860165	Der Assets 100m Cs 229
1860166	Der Assets 100m Wf 217
1860167	Der Assets 100m Ms 227
1860168	Der Assets 100m Boa 222
1860169	Deferred Debits - St Int Upool
1860170	Deferred Dr - Ncr
1860171	Deferred Dr - Emc Teradata
1860172	Deferred Dr-dino Software
1860173	Deferred Dr - Facetime
1860174	Misc Def Debit-commitment Fees
1860175	Deferred Dr - Emc
1860176	Deferred Dr - Adobe Generator
1860177	Defer Dr - Computer Associates
1860178	Defer Dr - Sirius

1860179	Defer Dr - Clearwell
1860180	Defer Dr - Infoprint Solutions
1860181	Defer Dr - Trend Micro
1860182	Defer Dr - Secure Computing
1860183	Defer Dr - Omnitrends
1860184	Defer Dr - Configuresoft
1860185	Defer Dr - Xo Soft
1860186	Defer Dr - Websense
1860187	Other Deferred Debits-35m Swap
1860188	Defer Dr - Intrust
1860189	Defer Dr - Emc Back Up
1860190	Plex Lease Buyout Cost
1860191	N Chas Hotel Property Lease Bu
1860192	300m Fair Value Hedge
1860193	250m Fair Value Hedge
1860194	Defer Dr - Capa
1860195	N Chas Prop-knts Inn-lease B C
1860196	Defer Dr - Cisco Smartnet
1860197	Deferred - Emc 2012 Refresh
1860198	Defer Dr - Siem
1860199	Defer Dr - Dynamix
1860200	Def Dr - Vcs Isfsi Maint
1860201	Def Dr - Vcs Inv Obs
1860202	Def Dr-vcs Wo Issuance
1860203	Defer Dr - Sms
1860204	Def Dr Decom Exp
1860205	Def Dr Vcs1 Trst Csh
1860206	Def Dr Vcs1 Trst Csv
1860207	Def Dr Decom Study
1860208	Def Dr - Proofpoint Prepaid
1860209	Def Dr Vcs Pens Inc Capital
1860210	Oth Def Debit 75m Jpm
1860211	Defer Dr - Entrust
1860212	Defer Dr - Nas
1860213	Ar-erips-sceg
1860214	Oth Def Debit 75m Db
1860215	Oth Def Debit 75m Ubs
1860216	Oth Def Debit 75m Bac
1860217	Der Assets $50m 3.625% Ubs
1860218	Deferred Debits Solo
1860219	Defer Dr - Avamar
1860220	Deferred - Ibm Maximo
1860221	Deferred - Netmotion Wireless
1860222	Deferred - Telerik
1860223	Deferred - Ibm Guardium
1860224	Deferred - Bmc Footprints

1860225	Deferred - Unidesk
1860226	Deferred - Hpt Xtremio
1860227	Deferred - Cisco Ise
1860228	Deferred - Workforce Software
1860229	Deferred - Hp Blades
1860230	Greenwood Call Option No-notic
1860231	Deferred Debit-energy Gateway
1860232	Unrealized G L Swaps Long-term
1860233	Unrealized Gl Options Lt
1860234	Unrealized Gl Mtm Contracts Lt
1860235	Deferred - Tripwire
1860236	Deferred - Bmc Perf Reporting
1860237	Deferred - Gartner Inc
1860238	Deferred - Palo Alto
1860239	Deferred -cisco Ela
1860240	Deferred -ibm Filenet
1860241	Interconnect Studies Deposit
1860242	Deferred - Palo Alto Cip5
1860243	Deferred - Entrust Cert Mgmt
1860244	Deferred - Infoblox
1860245	Deferred - Tripwire Cip5
1860246	Deferred - 2015 Emc Big Deal
1860247	Deferred Wildfire Apt For Isoc
1860248	Deferred Lockheed Palisade
1860249	Deferred-hp Carepacks
1860250	Sl Sci Tmoble Snee Farmtwr Ls
1860251	Sl-sci-new Cingular-pmc Space
1860252	Sl-sci-tmoble-colnl Hgts Twr L
1860253	Sl-sci-conterra-smoaks Twr Ls
1860254	Sl-sci-conterra-ehrhrdt Twr Ls
1860255	Sl-sci-motorola-pmc Roof Ls 1
1860256	Sl-sci-motorola-pmc Roof Ls 2
1860257	Sl-sci-sc Net-pmc Roof Ls
1860258	Sl-sci-pac & Sthrn-pmc Roof Ls
1860259	Sl-sci-nextel-pmc Roof Ls
1860260	Sl-sci-knology-chrl St Pop Ls
1860261	Sl-sci-new Cingular-pmc Roofto
1860262	Sl-sci-new Cingular-backup Gen
1860263	Sl-sci-ukenet-1401 Mn Pop Spc
1860264	Sl-sci-pmn-beaufort Rack Ls
1860265	Sl-sci-ist-1401 Mn Pop Space L
1860266	Sl-sci-pmn-pmc Rack Ls

1860267	Sl-sci-sc Net-pmc Pop Space Ls
1860268	Sl-sci-motorola-pmc Pop Spc Ls
1860269	Sl-sci-sst-pmc Pop Space Ls
1860270	Sl-sci-sst-pmc Rack Ls
1860271	Sl-sci-deltacom-pmc Rack Ls
1860272	Sl-sci-deltacom-pmc Pop Spc Ls
1860273	Sl-sci-nextel-pmc Pop Space Ls
1860274	Sl-sci-mci-pmc Rack Ls
1860275	Sl-sci-tw Telecom-pmc Rack Ls
1860276	Sl-sci-home Teleph-74 Fbr Main
1860277	Sl-sci-home Teleph-96 Fbr Main
1860278	Sl-sci-dukenet-1401 Mn Power
1860279	Sl-sci-conterra-blackville Twr
1860280	Sl-sci-comm Spec-cades Twr
1860281	Sl-sci-conterra-ehrhardt Twr
1860282	Sl-sci-knology-fab/chr Crgn/b
1860283	Sl-sci-knology-mnt-darby/mt Pl
1860284	Sl-sci-knology-mnt-3 Drk Fbrs
1860285	Sl-sci-compugrp-1401 Mn Space
1860286	Basis Swaps-long Term Asset
1860287	Cust Contrs-long Term Asset
1860288	Sl-sci-compugrp-1401 Mn Power
1860289	Der Assets $50m 3.635% Us Bank
1860290	Leasehold Improvements
1860291	Misc Def Dbt Jpm 242 Swap
1860292	Misc Def Deb Mizuho 243 Swap
1860293	Misc Def Dbt Ubs Swap #244
1860294	Misc Def Dbt Wf Swap #245
1860295	Misc Def Dbt Td Bank Swap #246
1860296	Misc Def Dbt Us Bank Swap #247
1860297	Deferral-crm/saleforce Cloud
1860298	Deferred-sea Jcl Plus
1860299	Deferred-rsa Archer
1860300	Mcmeekin - Solar
1860301	Ar Sfas 158 Serp - Svci
1860303	Ar Sfas 158 Serp - Semi
1860304	Ar Sfas 158 Serp - Psi
1860305	Def Dr-lt Rec Frm Psa-nuc Fuel
1860306	Def Dr Ar Psa Opeb

1860307	Ar Sfas 158 Serp - Cgtc
1860309	Ar Sfas 158 Serp - Sci
1860310	Deferred - Ibm Ela
1860311	Deferred - Autodesk
1860312	Clinton Newberry Call Option N
1860313	Ar Sfas 158 Serp - Sceg
1860314	Ar Sfas 158 Serp - Genco
1860315	Deferred - Cisco Cip
1860316	Defferred-micro Focus
1860317	Deferred - Qradar
1860318	Deferred - Redhat
1860319	Deferred - Solarwinds
1860320	Fed Amended Rtn Receivable
1860321	Deferred - Hp Printer Software
1860322	Deferred - Rubricks
1860323	Deferred - Red Gate
1860326	Ar Sfas 158 Serp - Sega
1860328	Ar Sfas 158 Serp - Psnc
1860329	Def Dr - Vcs Successfactors
1860400	Def Dr Kerp Csh Sur Val
1860401	Def Dr Pension Fund
1860402	Def Dr Co Contr To Stk Pln
1860403	Def Dr Dir Endowmnt Csv
1860404	Def Dr Kerp-hartford
1860405	Ar Int Inc Amended Rtn
1860500	Ami Project Consulting
1860501	Def Dr Svci True Up
1860503	Ar Pension Semi
1860504	Ar Pension Psi
1860505	Def Debit-ge Jasper $705k
1860506	Def Dr Sdc
1860507	Ar Pension Cgtc
1860509	Def Dr Sci
1860511	Def Dr Cgt Transition
1860512	Def Dr Ar Sh - Pensions
1860513	Ar Pension Sceg
1860515	Def Dr Prosolutions
1860516	Def Dr Subs Capital Charges
1860517	Def Dr Scpc Construction Oh
1860518	Def Dr Psnc Construction Oh
1860519	Def-wetland Mit Bank-bushy Pk
1860520	Def-wetland Mit Bank-canadys
1860521	Der Asset Morgan Stanley #256
1860522	Der Asset Boa #258
1860523	Der Asset -wf #257

1860524	Def Dbts Swap #260 Mub
1860525	Def Dbts Swap #261 Tdb
1860526	Ar Pension Sega
1860527	Def Dbts Swap #262 Rbc
1860528	Ar Pension Psnc
1860529	Def Dbts Swap #263 Credit Suis
1860530	Ar Pension Ssec
1860531	Def Dbts Swap #265 Morgan Stan
1860532	Ar Pension Psa
1860533	Ar Pension Fas 158
1860534	Def Dbts Swap #266 Boa
1860535	Ar Pension Scg Pipeli
1860601	Ar Opeb Svci
1860603	Ar Opeb Semi
1860604	Ar Opeb Psi
1860607	Ar Opeb Cgtc
1860609	Ar Opeb Sci
1860613	Ar Opeb Sceg
1860614	Ar Opeb Genco
1860626	Ar Opeb Sega
1860628	Ar Opeb Psnc
1860632	Ar Opeb Psa
1860701	Ar Lt Sfas 112 Svci
1860703	Ar Lt Sfas 112 Semi
1860707	Ar Lt Sfas112 Cgtc
1860709	Ar Lt Sfas 112 Sci
1860713	Ar Lt Sfas 112 Eg
1860726	Ar Lt Sfas 112 Sega
1860728	Ar Lt Sfas 112 Psnc
1860801	Ar Lt Disability Svci
1860803	Ar Lt Disability Semi
1860807	Ar Lt Disability Scpc
1860809	Ar Lt Disability Sci
1860813	Ar Sceg Lt Disability
1860826	Ar Lt Disability Sega
1860828	Ar Lt Disability Psnc
1860835	Ar Lt Disability - Scg
1860901	Ar Director Endowmwnt Svci
1860903	Ar Director Endowment Semi
1860904	Ar Director Endowment Psi
1860907	Ar Director Endowment Scpc
1860909	Ar Director Endowment Sci
1860913	Ar Sceg-directors Endowment
1860914	Ar Director Endowment Genco
1860915	Eg Receivable From Sh - Edcp F
1860926	Ar Director Endowment Sega

1860928	Ar Director Endowment Psnc
1860935	Ar Director Endowment Scg
1860940	Ar Director Endowment Sega
1860941	Ar Director Endowment Serg
1860950	Csv Due From Sh For Dir Endow
1862003	Hedge Transactions
1863011	Reg Asset Psnc Def Gas Costs
1863012	Misc Dfred Dbts - Spare Parts
1863601	Reg Asset-poll Cntrl-wms Scrbr
1880000	Research And Development
1890000	Unamrtzd Loss On Reacqurd Debt
1890101	Unamort Loss 9 7/8% Due 2000
1890102	Umamort Loss 16% Due 6/1/11
1890103	Unamort Loss Berkeley Co
1890105	Unamort Loss 12.15% Due 2010
1890106	Unamort Loss 10 1/8% Due 2009
1890107	Unamort Loss 8% Due 6/1/99
1890108	Unamrt Loss 9 1/8% Due 6/15/23
1890109	Unamort Loss 8% Due 3/1/01
1890110	Unamort Loss 9 1/8% Due 2/1/06
1890111	Unamort Loss 8.40% Due 6/15/23
1890112	Unamrt Loss 8 3/8% Due 6/15/23
1890113	Unamort Loss 8.90% Due 6/15/23
1890114	Unamort Loss 9 7/8% Due 6/1/09
1890115	Unamort Loss 8.75% Due 2/1/17
1890118	Unamort Loss 14% Due 97
1890119	Unamort Loss 11.5%
1890120	Unamrt Loss 8 7/8% Due 8/15/21
1890121	Unamort Loss 9% Due 7/15/06
1890122	Unamort Loss 7 1/4% Due 2002
1890123	Unamrt Loss Reacq Dbt 7 1/4
1890124	Un Loss Acqd 300mtn 2 10 03
1890125	Un Loss Reac Dbt Fairfldco1984
1890126	Un Loss Reac Dbt Fairfield1986
1890127	Un Loss Reacq Dbt-col/dor 1987
1890128	Unam Loss Reacq Debt 56910000
1890129	Unamt Debt Exp 5.20% Bonds
1890130	Unamort Debt Exp 5.45% Bonds

1890131	Unm Loss Recq Dbt 100m 5 25 Bd
1890132	Unam Loss 7 5/8 Due 4 1 2025
1890133	Unam Loss 3 22 Due 10 18 21
1890134	Unam Loss Reacq Debt 29150000
1890173	Unam Loss 8 7/8% Due 8/15/21
1890174	Unamort Loss Reacq Debt
1890175	Unam Loss On Reacq Debt 50m Pr
1890177	Unamort Loss Reacq Debt
1890178	Unam Loss Reacq Dbt 50m Prf Tr
1890184	Unam Loss Reacq Dbt - Richland
1900000	Accum Deferred Income Taxes
1900001	Adit Fed Nuc Fuel Amort
1900002	Adit St Nuc Fuel Amort
1900003	Adit Fed Elec Rate Refund
1900004	Adit Fed Gas Rate Refund
1900005	Adit St Elec Rate Refund
1900006	Adit St Gas Rate Refund
1900007	Adit Fed Def Fuel
1900008	Adit St Def Fuel
1900009	Adit Fed Elec Itc Fasb 109
1900010	Adit Fed Gas Itc Fasb 109
1900011	Adit Fed Tran Itc Fasb 109
1900012	Adit St Elec Itc Fasb 109
1900013	Adit St Gas Itc Fasb 109
1900014	Adit St Tran Itc Fasb 109
1900015	Adit Fed Elec Kerp
1900016	Adit Fed Gas Kerp
1900017	Adit Fed Tran Kerp
1900018	Adit Fed Nonoper Kerp
1900019	Adit St Elec Kerp
1900020	Adit St Gas Kerp
1900021	Adit St Tran Kerp
1900022	Adit St Nonoper Kerp
1900023	Adit Fed Elec Erip
1900024	Adit Fed Gas Erip
1900025	Adit Fed Tran Erip
1900026	Adit Fed Nonoper Erip
1900027	Adit St Elec Erip
1900028	Adit St Gas Erip
1900029	Adit St Tran Erip
1900030	Adit St Nonoper Erip
1900031	Adit Fed Elec Bonus Plan

1900032	Adit Fed Gas Bonus Plan
1900033	Adit Fed Tran Bonus Plan
1900034	Adit St Elec Bonus Plan
1900035	Adit St Gas Bonus Plan
1900036	Adit St Tran Bonus Plan
1900037	Adit Fed Elec Epa Cleanup
1900038	Adit Fed Gas Epa Cleanup
1900039	Adit St Trans Env Clean Up
1900040	Adit St Non Op Env Clean Up
1900041	Adit St Elec Epa Cleanup
1900042	Adit St Gas Epa Cleanup
1900043	Adit Fed Trans Env Clean Up
1900044	Adit Fed Non Op Env Clean
1900045	Adit Fed Nuc Refuel
1900046	Adit St Nuc Refuel
1900047	Adit Fed Nuc Decom
1900048	Adit Fed Nuc Decom Oth Inc
1900049	Adit St Nuclear Decom
1900050	Adit St Nuc Decom Oth Inc
1900051	Adit Fed Otarre Basis
1900052	Adit St Otarre Basis
1900053	Adit Fed Elec Pal Ctr
1900054	Adit Fed Gas Pal Ctr
1900055	Adit Fed Tran Pal Ctr
1900056	Adit Fed Nonoper Pal Ctr
1900057	Adit St Elec Pal Ctr
1900058	Adit St Gas Pal Ctr
1900059	Adit St Tran Pal Ctr
1900060	Adit St Nonoper Pal Ctr
1900061	Adit Fed Elec Unbill Rev
1900062	Adit Fed Gas Unbill Rev
1900063	Adit St Elec Unbill Rev
1900064	Adit St Gas Unbill Rev
1900065	Adit Elec Fed Closed Non-hedge
1900066	Adit Elec St Closed Non-hedges
1900067	Adit Fed Elec Uncoll Accts
1900068	Adit Fed Gas Uncoll Accts
1900069	Adit St Elec Uncoll Accts
1900070	Adit St Gas Uncoll Accts
1900071	Adit Fed Elec Inj And Dam
1900072	Adit Fed Gas Inj And Dam
1900073	Federal - Injuries And Damages
1900074	Adit St Elec Inj And Dam
1900075	Adit St Gas Inj And Dam
1900076	State - Injuries And Damages
1900077	Adit Fed Elec Opeb

1900078	Adit Fed Gas Opeb
1900079	Adit Fed Tran Opeb
1900080	Adit St Elec Opeb
1900081	Adit St Gas Opeb
1900082	Adit St Tran Opeb
1900083	Adit Fed Nonop Opeb
1900084	Adit St Nonop Opeb
1900085	Unamort Software Adit Fed
1900086	Unamort Software Adit St
1900087	Compensation Adit Fed
1900088	Compensation Adit St
1900089	Palmetto Seed Capital Adit Fed
1900090	Palmetto Seed Capital Adit St
1900091	Fed-scana Security Organ Cost
1900092	St -scana Security Organ Cost
1900093	Invest Scri Adit Fed
1900094	Invest Scri Adit St
1900095	Write Down Scri Adit Fed
1900096	Write Down Scri Adit St
1900097	Gapnol Scri Adit Fed
1900098	Gapnol Scri Adit St
1900099	Write Down Invest Adit Fed
1900100	Write Down Invest Adit St
1900101	Write Down Sdc Adit Fed
1900102	Write Down Sdc Adit St
1900103	Adit Fed Elec St Inv Tax Crdts
1900104	Adit Fed Gas St Inv Tax Crdts
1900105	Adit Fed Elec Storm Dmg Accrls
1900106	Adit St Elec Storm Dmg Accrls
1900107	Adit Federal Palmetto Lime
1900108	Adit State Palmetto Lime
1900109	Federal - Lawsuit
1900110	State - Lawsuit
1900111	Adit-fed-elec-franchise Fees
1900112	Adit-fed-gas-franchise Fees
1900113	Adit-fed-transit-franchise Fee
1900114	Adit-st-elec-franchise Fees
1900115	Adit-st-gas-franchise Fees
1900116	Adit-st-transit-franchise Fees
1900117	Adit-psnc Federal Deferred Buy
1900118	Adit-psnc State Deferred Buy/s
1900119	Adit-psnc Fed Def Gas Sales Cu
1900120	Adit-psnc State Def Gas Sales
1900121	Adit-fed Psnc Insurance Reserv
1900122	Adit-state Psnc Insurance Rese
1900123	Adit-fed Psnc 263 Adj To Inv

1900124	Adit-state Psnc 263 Adj To Inv
1900125	Adit-fed Psnc Stock Option
1900126	Adit-state Psnc Stock Option
1900127	Adit-fed Psnc Severance
1900128	Adit-state Psnc Severance
1900129	Adit-fed Psnc Benefit Restor
1900130	Adit-st Psnc Benefit Restor
1900131	Adit Psnc Reg Debit State Taxe
1900133	Adit Fed Psnc Ex Npl Reg Liab
1900134	Adit St Psnc Ex Nonpl Reg Liab
1900135	Adit-fed Lost And Unacctd For
1900136	Adit-state Lost And Unacctd Fo
1900137	Adit Fed Elec Ltd
1900138	Adit Fed Gas Ltd
1900139	Adit St Elec Ltd
1900140	Adit St Gas Ltd
1900141	Adit Fed Nonoper Ltd
1900142	Adit St Nonoper Ltd
1900143	Adit Fed Elec Accrued Vacation
1900144	Adit Fed Gas Accrued Vacation
1900145	Adit Fed Btl Accrued Vacation
1900146	Adit St Elec Accrued Vacation
1900147	Adit St Gas Accrued Vacation
1900148	Adit St Btl Accrued Vacation
1900149	Adit-fed Def Pipeline Integ
1900150	Adit-st Def Pipeline Integ
1900151	Adit-fed-int Rate Lock
1900152	Adit-state-int Rate Lock
1900153	Adit Fed Wetland Accrual Elec
1900154	Adit St Wetland Accrual Elec
1900155	Adit Fed Elec Research Payment
1900156	Adit St Elec Research Payment
1900157	Adit - Oci - Serp Federal
1900158	Adit - Oci - Serp State
1900159	Adit Fed Nonoper Ferc Reserve
1900160	Adit St Nonoper Ferc Reserve
1900161	Adit Fed - Directors Endowment
1900162	Adit St - Directors Endowment
1900163	Adit St Elec Major Maint
1900164	Adit St Gas Major Maint
1900165	Adit Fed Elec Major Maint
1900166	Adit Fed Gas Major Maint
1900167	Adit St Elec Unearned Rev
1900168	Adit St Gas Unearned Rev

1900169	Adit Fed Elec Unearned Revenue
1900170	Adit Fed Gas Unearned Revenue
1900171	Accum Defer Inc Tax-state-ltd
1900172	Accum Defer Inc Tax-fed-ltd
1900173	Accum Defer Inc Tax-st-opeb
1900174	Accum Defer Inc Tax-fed-opeb
1900175	Accum Defer Inc Tax-st-pension
1900176	Accum Defer Inc Tax-fed-pensi
1900177	Adit Fed Wetland Accrual Btl
1900178	Adit St Wetland Accrual Btl
1900179	Adit Fed St Tax Deduct Eiz
1900180	Adit Fed St Tax Ded Eiz-gas
1900181	Adit Fed Recover Line Pack
1900182	Adit St Recoverable Line Pack
1900183	Adit Fed Burton Insurance
1900184	Adit St Burton Insurance
1900185	Adit-state 2010 Swap-boa
1900186	Adit-fed 2010 Swap-boa
1900187	Adit-fed 2010 Swap-wachovia
1900188	Adit-state 2010 Swap-wachovia
1900189	Adit-state 2010 Swap-mizhuo
1900190	Adit-fed 2010 Swap-mizhuo
1900191	Adit-st - Bank Of Ny Mellon
1900192	Adit-fed- Bank Of Ny Mellon
1900193	Adit-fed- Boa Swap
1900194	Adit-state - Boa Swap
1900195	Federal Non Operating-serp
1900196	State Non Operating-serp
1900197	Fed Non Oper Serp Interco
1900198	St Non Oper Serp Interco
1900199	Adit Fed Amt Cr Carryforward
1900200	Accum Def Federal Income Tax
1900201	Adit Fed Psnc Merger Costs
1900202	Adit State Psnc Merger Cost
1900203	Warburg Swap Adit Fed
1900204	Warburg Swap Adit St
1900205	Invest In Stock Adit Fed
1900206	Invest In Stock Adit St
1900207	Rabbi Director Adit Fed
1900208	Rabbi Director Adit St
1900209	Federal - Edcp
1900210	State - Edcp
1900211	Adit Federal-start Up Costs
1900212	Adit State-start Up Costs

1900213	Adit State West Texas
1900214	Adit Federal Primesouth
1900215	Adit State Primesouth
1900216	Adit - Fed - 2007 Swap
1900217	Adit - State - 2007 Swap
1900218	Adit - Fed - 2008 20m Swap
1900219	Adit - State - 2008 20m Swap
1900220	Adit - Fed Gas Non Rec Wsh Gas
1900221	Adit - St Gas Non Rec Wsh Gas
1900222	Adit - Fed Gas Rec Line Pack
1900223	Adit - St Gas Rec Line Pack
1900225	Adit - Fed Elec Calpine
1900226	Adit - St Elec Calpine
1900227	Adit - Fed Gas Rec Wsh Gas
1900228	Adit - St Gas Rec Wsh Gas
1900230	Adit - Fed Gas Calpine
1900231	Adit - St Gas Calpine
1900232	Adit-state-goodwill Basis Diff
1900233	Adit-fed-goodwill Basis Differ
1900234	Adit St Nol And Credits
1900235	Adit - Fed - 2008 T Lock
1900236	Adit - St - 2008 T Lock
1900237	Adit - Fed - Sci Contingency R
1900238	Adit - State - Sci Contingency
1900240	Adit - Fed Gas 263a
1900241	Adit - St Gas 263a
1900243	Def Tax Asset-oci
1900244	Def Tax Asset State-oci
1900245	Def Inc Tax - State Nol
1900246	Adit Fed Def Cr Cable Pole
1900247	Adit St Def Cr Cable Pole
1900250	Adit-state-contribution Limit
1900251	Unrealized Gain Loss Financial
1900252	Def Tax Fed-energy America
1900253	Def Tax Fed Unrealiz G And L
1900254	Def Tax Fed-inventory Cap
1900255	Def Tax State-unrealized Loss
1900256	Def Tax State-energy America
1900257	Def Tax State Unrealiz G And L
1900258	Def Tax Fed-emc Noncompete
1900259	Def Tax St-emc Noncompete
1900260	Adit-federal-ciac
1900261	Adit-state-ciac
1900262	Adit-federal-sect 481 Adj
1900263	Adit-state-sect 481 Adj
1900264	Adit-federal-basis Difference

1900265	Adit-state-basis Difference
1900267	Adit Fed Elec Long Term Pledge
1900268	Adit-state-inventory Cap
1900269	Adit St Elec Long Term Pledges
1900270	Adit-fed Prop Basis-hist Data
1900271	Adit-state Prop Basis-hist Dat
1900272	Adit Fed Pal Ctnr Litigation
1900273	Adit St Pal Ctnr Litigation
1900274	Adit Fed Reg Asset Enviromenta
1900275	Adit St Reg Wat Scrubber
1900276	Adit Fed Reg Wat Scrubber
1900277	Adit St Reg Asset Enviromental
1900278	Adit Fed Elec Aro Liability
1900279	Adit St Elec Aro Liability
1900280	Adit Fed Gas Aro Liability
1900281	Adit St Gas Aro Liability
1900282	St Elec Nol And Credit
1900283	Federal - Capital Loss Carryov
1900284	Adit - Fed Reg Liability-curre
1900285	Adit - St Reg Liability-curren
1900286	Adit - Fed Reg Asset-fuel Trac
1900287	Adit - St Reg Asset-fuel Track
1900288	Fed Elec Nol And Credit
1900290	Compensation Adit Fed Elec
1900291	Compensation Adit St Elec
1900292	Compensation Adit Fed Gas
1900293	Compensation Adit St Gas
1900294	Federal - Edcp Elec
1900295	State - Edcp Elec
1900296	Federal - Edcp Gas
1900297	State - Edcp Gas
1900298	Rabbi Director Adit Fed Elec
1900299	Rabbi Direct Adit St Elec
1900300	Accum Def State Income Tax
1900301	St Elec Opeb Fas 158
1900302	St Gas Opeb Fas 158
1900304	Rabbi Director Adit Fed Gas
1900305	Rabbi Direct Adit St Gas
1900306	Fed Elec Opeb Fas 158
1900307	Fed Gas Opeb Fas 158
1900309	Def Inc Tax - State Nol
1900310	Fed Elec Nol
1900311	Fed Gas Nol
1900312	Fed Btl Nol
1900313	St Elec Nol
1900314	St Gas Nol

1900315	St Btl Nol
1900316	Fed Elec Credit
1900317	Fed Gas Credit
1900318	Fed Btl Credit
1900319	Sc Elec Credit
1900320	Sc Gas Credit
1900321	Sc Btl Credit
1900400	Adit Fed Bad Debt
1900401	Adit St Bad Debt
1900402	Adit Fed Bonus
1900403	Adit St Bonus
1900404	Adit Fed Warrant
1900405	Adit St Warrant
1900406	Adit Fed Prepayments
1900407	Adit St Prepayments
1900408	Adit Fed Toshiba Settlement
1900409	Adit St Toshiba Settlement
1900410	Adit Fed Impairment Charge
1900411	Adit St Impairment Charge
1900412	Adit Fed Nuc Fuel Impairment
1900413	Adit St Nuc Fuel Impairment
1900500	Adit - Fed Deferred Revenue
1900501	Adit State Deferred Revenue
1900600	Adit Fed Investment In Frc
1900610	Adit State Investment In Frc
1900700	Fed Adit Elec Tax Rate Change
1900701	St Adit Elec Tax Rate Change
1900702	Fed Adit Gas Tax Rate Change
1900703	St Adit Gas Tax Rate Change
1900704	Fed Adit Elec Prop Tax Rate Ch
1900705	St Adit Elec Prop Tax Rate Chg
1900706	Fed Adit Gas Prop Tax Rate Chg
1900707	St Adit Gas Prop Tax Rate Chg
1900900	Adit St Pine Needle Int Swap
1900901	Adit Fed Pine Needle Int Swap
1950500	Adit Fed Deferred Revenue
2010000	Com Stk Issued
2010001	Com Stk Issued Peoples
2010002	Common Capital Securities
2010003	Common Stock Repurchased
2010004	Unearned Compensation
2020000	Com Stk Subscribed
2040000	Pref Stk Iss Not Sub Pur-sk Fd
2040001	Pref Stk Iss Subj Pur Or Sk Fd
2040002	Preferred Stock - 2010 Issue
2040003	Trust Preferred Securities
2070000	Prem On Capital Stk

2080000	Donations From Stockholders
2100000	Gain Resle Or Cncl Req Cap Stk
2100001	Gain On Reacquired Cap Stock
2110000	Misc Paid In Cap Org Adv-sceg
2110003	Misc Paid In Cap Org Adv-ssec
2110004	Misc Paid In Cap Org Adv-tech
2110005	Other Comprehensive Inc - Serp
2110014	Sci Unrealized Gain
2110015	Fas 133 Hedging
2110016	Psnc Comprehensive Income
2110017	Scpc Comprehensive Income
2110018	Scana Comprehensive Income
2110100	Misc Paid In Capital
2110101	Misc Pd Cap Non Int Adv Scana
2110200	Investment Impairment
2111700	Sceg Comprehensive Income
2140000	Capital Stock Expense
2140010	Pref Stk Exp-trust
2140011	Pref Stk Exp-other
2151000	App Ret Earn Amt Resv Fed Proj
2160000	Unapp Retained Earnings
2160001	Unap Ret Earn Pro-div Pref Stk
2160002	Unapp Ret Earn Misc Debit
2160003	Unapp Retained Earnings- Ssec
2160004	Unapp Retained Earnings- Tech
2160059	Oci-2010 Swap-boc
2160067	Oci-2010 Swap-wachovia
2160068	Oci-2010 Swap-mizhuo
2161001	Equity In Subs Earn Svci
2161002	Equity In Subs Earn Sps
2161003	Equity In Subs Earn Semi
2161004	Equity In Subs Earn Psi
2161005	Equity In Subs Earn Spr
2161006	Equity In Subs Earn Sdc
2161007	Equity In Subs Earn Scpc
2161008	Equity In Subs Earn Spg
2161009	Equity In Subs Earn Sci
2161010	Eq In Subs Earn Scfc
2161011	Equity In Subs Earn Westex
2161013	Equity In Subs Earn Sceg
2161014	Equity In Subs Earn Genco
2161015	Equity In Subs Earn Sr
2161020	Equity In Sub Earnings Lpg
2161021	Equity In Sub Earnings Finance
2161022	Equity In Sub Earnings Product

2161023	Equty In Sub Earnings Sps
2161024	Equity In Sub Earnings Sssi
2161025	Equity In Sub Earnings Peoples
2161026	Equty In Sub Earnngs Supertane
2161027	Equity In Sub Earnings Scri
2161028	Equity In Sub Earnings Psnc
2161035	Equity In Subs Earn Scg
2169999	Cur Mo Retd Earn
2170001	Reacquired Capital Stock
2190001	Oci-sfas 158 Adj
2190002	Oci-cgt Sfas 158 Adj
2190003	Oci-sci Sfas 158 Adj
2190004	Oci-svci Sfas 158 Adj
2190007	Scpc Oth Comprehensive Income
2190008	Oci - 2007 Swap
2190009	Oci-2008 Cana Lock-unwind
2190010	Oci - 2008 20m Swap
2190015	Other Comprehensive Inc - Semi
2190016	Other Comprehensive Inc-psnc
2190017	Other Comprehensive Inc-sceg
2190018	Serp Minimum Liability
2190057	Oci - Boa Swap
2190058	Oci - Mny Mellon Swap
2190059	Oci - 2010 Swap - Boa
2190067	Oci - 2010 Swap - Wachovia
2190068	Oci - 2010 Swap - Mizuho
2199999	Oci- Federal Tax Rate Chg
2210000	Bonds
2210001	Bonds Pollut Control Bonds
2210002	Bonds -pollution Control 2003
2210003	Bonds-industrial Rev-gn Scrubr
2210100	Bonds Current Portion
2210101	Bonds Curr Portion Contra
2210102	Warburg Swap Liability
2210103	Warburg Swap Settlement
2230000	Adv From Assoc Co
2230001	Advances From Sci
2230005	Advances From Assoc Co - Spr
2230006	Advances From Assoc Co - Sdc
2230012	Advances From Assoc Co - Scana
2230013	Adv From Assoc Co-non Affilted
2230014	Adv Frm Assoc Co Piedmont

2230015	Lt Note Payable - Sh
2230028	Adv Frm Assoc Co Psnc
2230038	Adv From Sci To Sci Subs
2240000	Oth Ltd Orig Adv From Sceg
2240001	Oth Ltd 60m Term Loan
2240002	Oth Ltd 7year Notes
2240003	Oth Ltd Med Term Notes
2240004	Jr Subrdntd Debntrs-sceg Trust
2240005	Note-prudential 20yr 02 01 24
2240006	Oth Ltd-40m Sr Fltg Notes 6 1
2240007	Oth Ltd-note-genco 2008 Due 20
2240043	Other Long Term Debt - Swap Tv
2240100	Oth Ltd
2240101	Oth Ltd Fuel
2240102	Oth Ltd Allowances
2240103	Oth Ltd Term Loan
2240104	Oth Ltd Dbase Mgmt Note
2240105	Oth Ltd Wateree Trbn Bkts
2240106	Oth Ltd 10% 2004
2240107	Oth Ltd 8.75% 2012
2240108	Oth Ltd 6.99% 2026
2240109	Oth Ltd 7.45% 2026
2240110	Oth Ltd 6.625% 2011
2240111	Warburg Swap Settlement
2240112	Warburg Swap Cancellation
2240113	5 81 Swap Unwind Due 10 23 20
2240114	6 25 Swap Unwind Due 2 1 2012
2240115	Oth Ltd Cafb 2027
2240116	Long Term Debt-equit And Amer
2240117	Alternate Base Rate Loan 5 Pct
2240118	Other Ltd-loc Loans
2240119	300m Fair Value Debt - Offset
2240120	250m Fair Value Debt - Offset
2240121	Other Ltd-6 54 2020
2240122	Other Ltd-4 59 Due 2021
2240123	Other Lt Debt Nuclear Fuel
2240124	Other Ltd-4 13% Due 2046
2240125	Other Ltd-4.18% Due 2047
2240140	Other Ltd - 2009 Hybrid Notes
2240200	Oth Ltd Current Portion
2240201	Oth Ltd Curr Portion Contra
2240202	Oth Ltd 10% 2003
2240203	Oth Ltd 10% 2004
2240204	Oth Ltd - Turbine Spare Parts

2240205	Oth Ltd - Stator Bars Prts Com
2240206	State Infrastructure Bank Loan
2250000	Unamort Prem Ltd
2250101	Unamrtzd Premiums Long Term De
2250102	Unamortized Premiums Other Ltd
2250103	Un Premium Ltd 5 8% Due 1 15 3
2250104	T-lock Unwind 6 25% Due 2036
2250105	Unam Prem 250m 6 05% Bonds
2250106	Unam Lock Prem 250m Mtn Due 4-
2250107	Bond Premium 5.45% Due 02/01/4
2250108	Bond Premium 4 35 Due 2 1 42
2250109	Bond Prem-$39.480m 4pct Bonds
2260000	Unamort Disc Ltd
2260001	Unamorttized Disc-berk Co 2003
2260007	Unam Disc Ltd 400m 4 6 6152043
2260008	Unam Disc 5.1% $500m Bonds
2260101	Unamt Disc 6.625% Due 02/01/32
2260102	Un Dis 5 8% Due 1 15 33
2260103	Unam Disc 250m Mtn Due 4-1-202
2260104	Unam Disc 6 25% Due 2036
2260105	Unam Disc Ltd 6% 1997
2260106	Una Disc 7 50% 6 2005 Bonds
2260107	Unam Disc 6 7% Due 2/1/2011
2260108	Disc 6 875% 300m 5 15 2011
2260109	Unamort Disc $250m 6.25% Mtn
2260110	Unam Disc 250m 6 05% Bonds
2260111	Unamrt Disc 300m
2260112	Unamort Disc 250m Due 02/01/22
2260113	Unamort Disc 250m Due
2260114	Unam Disc Ltd 9% 2006
2260115	Unam Disc Ltd 8 7/8%
2260116	Unam Disc Ltd 7 5/8% 2023
2260117	Unam Disc Ltd 6% 6/15/00
2260118	Unam Disc Ltd 7 1/8% 6/15/13
2260119	Unam Disc Ltd 7 1/2% 6/15/23
2260120	Unam Disc Ltd 7 70% 7/15/04

2260121	Un Disc 6 5 Series Due
2260122	Unamort Disc $14.735m 3.625pct
2260123	Unamort Disc On Ltd-nuc Fuel
2260125	Unamrt Disc $300m 4.5% Due 6/1
2260139	Un Disc 2009 Fmb
2260145	Unam Disc 250m Fmb Due 02 01 2
2260159	Unam Disc Ltd 6 1/8% 3/1/09
2260161	Unamort Disc 5 3% Due 5 15 33
2260162	Un Disc 5 3% Due 5 15 33 Lock
2260163	Un Disc 5 25% Bonds 11 1 2018
2260164	5 25% Forward Swap 11 1 2018
2260165	Unam Dis 5.25% T-lock Unwind
2260166	Unam Disc 5.25 Bnds Due 3 1 35
2260167	Unam Disc $425mm 4.1% Series D
2270000	Obligation Under Capital Lease
2270001	Obligation Under Capital Lease
2270002	Obligation Under Capital Lease
2270088	Cap Lease Non Curr Monroe Pipe
2282000	Acc Pro Inj And Dam Claims
2282001	Acc Pro Inj And Dam Tr Cola
2282002	Acc Pro Inj And Dam Tr Chas
2282003	Acc Pro Inj & Dam Post Trnsfr
2282004	Acc Pro Inj & Dam Retain Liab
2282010	Acc Pro Inj And Dam Work Comp
2282011	Acc Pro Inj & Dam Wk Cp Tr Col
2282012	Acc Pro Inj & Dam Wk Cp Tr Cha
2282013	Acc Pro Inj-dam Wk Cp Pst Trn
2282014	True Up For Actuary Wc Reserv
2282015	W C Ibnr Reserve
2282016	Inj And Dam Claims Saluda Dam
2282017	Acc Pro Work Comp Nnd
2283000	Acc Pro Pens And Benef Srp
2283001	Acc Pro Pen & Ben Dental
2283002	Acc Pro Pen & Ben Std
2284000	Acc Misc Oper Pro Div
2284001	Acc Msc Oper Pro Emp Home Loss
2284002	Ac Misc Opr Pro Doe D & D Fnd
2284003	Acc Msc Op Pro Cha Frch Pmttra
2284004	Acc Msc Op Pro Cha Fran Envr S

2284005	Lt Cola Farnchise Obligations
2284006	Otarri Wetland Remediation
2290000	Accum Provision For Rate Refun
2300000	Asset Retirement Oblig - Vcs
2300001	Aro - Electric And Gas
2300002	Aro Layer 2 - Vcs
2300003	Aro Layer 3 - Vcs
2300004	3rd Layer Aro - E And G
2300006	Aro Liability
2300007	Sco Aro Liability
2310000	Notes Payable
2310001	Notes Pay Psnc Comm Paper
2310002	Notes Pay Psnc Merrill Lynch
2310100	Other Notes Payable Fuel
2310137	Clear Well Payable
2310200	Other Notes Pay Allowances
2320000	Apay
2320001	Apay Fuel Liabilities
2320002	Apay Psa Pen Inc Acc
2320003	Apay Manual Accrual
2320004	Apay D & T Prior Yr Audit Fees
2320005	Apay D & T Curr Yr Audit Fees
2320006	Apay Cust Surety Bonds
2320007	Accr Csts For Telecom Grp Yrly
2320008	Hydro Water Sampling
2320009	Accrued Liab - Apt Unit Fees
2320010	Apay Natural Gas Supply
2320011	Apay Gas Costs
2320012	Apay Ferc Settlement
2320013	Ap Manual Accruals - Inc Stmnt
2320014	Apay Dealer Sales Financing
2320015	2nd Injury Fund
2320016	Ap Short Upstream Oba Imbalanc
2320017	Non Assoc Co Ap Other
2320018	Accrued Liab - Occupational Ta
2320019	Accrued Liab - Delta
2320020	Accrued Liab - Property Tax
2320021	Accrued Liab - Company Credit
2320022	Accrued Liab Emc Non-compete
2320023	Ap Manual Accruals-bal Sheet
2320024	Scana-cc- Cash Clearing
2320025	Hedges - Broker Ap
2320026	Apay Pledge Accrual
2320027	Oth Ap - Otc Hedging

2320028	Wtr Htr 3rd Party Financing
2320029	Ap Gas Log 3rd Party Financing
2320030	Ap Propane Conv 3rd Party Finc
2320031	Other Apay Cog Cashouts
2320037	Accounts Payable - Southern Na
2320050	Ap - Margin Calls Payable
2320051	Ap Gas Costs Estimated
2320052	Current Otc Swaps Payable
2320053	Ap Mgmt Fees
2320054	Ap Apga Surcharge
2320055	Ap Intermarket
2320056	Current Basis Swaps
2320099	Apay Psa Doe Settlement
2320100	Accounts Payable - Peoplesoft
2320101	Apay Santee Cooper Cns
2320102	Apay Cope Allow Acq Costs
2320103	Apay Stvn Ck Hdwtr Bene Chg
2320104	Apay Quest Software
2320105	Ist Roadrunner Payroll Deducti
2320106	Apay Disp Costs Nuc Two 3rds
2320107	Apay Disp Costs Psa
2320108	Apay Un Camp Corp Pur Pw
2320109	Apay Proj Share Donate
2320110	Apay Pal Ctr Lease Pmts
2320111	Apay Superior Rating
2320112	Apay Ferc Annual Bill Chg
2320113	Apay Title V Air Ems Fees
2320114	Apay Gas Coop Advert
2320115	Apay Dep Lk Murray Dig
2320116	Apay Mms Rcpts Accrue
2320118	Apay Accr Rcpts Liab
2320119	Apay Nonstock Rcpts Acrl Psft
2320120	Apay Finance Acctg
2320121	Apay Bulk Pwr And Transmission
2320122	Apay Scana
2320123	Apay Ms Enterpr Agmnt Consl
2320124	Apay Macro4 Inc.
2320125	Apay - Computer Assoc
2320126	Apay Harvest Inc
2320127	Pest Patrol Accts Pay
2320128	Compuware Sch 24 Apay
2320129	Ca Unictr Asset Mtg
2320130	Computer Software Contracts
2320131	Microsoft Enterprise
2320132	2320132 Ncr

2320133	Dino Software
2320134	Liability - Ems
2320135	Sirius
2320136	Cisco Smart Net
2320137	Clear Well Payable
2320138	Infoprint Solutions Payable
2320140	Zantax Payable
2320150	Remarketing Agent Fees Accrued
2320200	Apay Pace
2320201	Apay-dominion
2320202	Ap Rinnai Lowe's Referral Prog
2320300	Apay Emp Ded Sav Bnds
2320301	Apay Emp Ded For Life Ins
2320302	Apay Addl Annuities
2320303	Apay Addl Annuities Officers
2320304	Apay Emp Ded For Sav Pln Stk
2320305	Apay Emp Ded Add Sav Pln Stk
2320306	Apay Tax Def Sav Stk
2320307	Apay Emp Ded 401k Loan
2320308	Apay Emp Ded Dpnd Hlth Care
2320309	Apay Emp Ded Dental Care
2320310	Apay Emp Ded Grp Life Ins
2320311	Apay Emp Ded Ad And D Ins
2320312	Apay Emp Ded St Disb Ins
2320313	Apay Emp Ded Lt Disb Ins
2320314	Apay Emp Ded Dep Life Ins
2320315	Emp Ded Grp Trm Optimal Lfe
2320316	Apay Emp Ded Auto And Home Ins
2320317	Apay Kerp
2320318	Apay Moving Exp
2320319	Apay Pension Fund
2320320	Apay Ltd Expense
2320321	Apay Flex Spending Instel
2320322	Apay Kymn Rtntn Pre Tax Dedct
2320323	Ap Emp Ded Psnc
2320324	Apay - Health Bank Drafts
2320325	Ee Recreational Club Deducts
2320326	Ee Union Dues Deducts
2320327	Ee Garnishment Deducts
2320328	Ee Credit Union Deducts
2320329	Ee Political Cont Deducts
2320330	Ee Advance Deducts
2320331	Ee Cancer Ins Deducts
2320332	Ee Donation Deducts
2320333	Ee Membership Dues Deducts

2320334	Ee Miscellaneous Deducts
2320335	Financial Planning Taxes
2320336	Employee Tuition Reimbursement
2320337	Scana Stock Option Taxes
2320338	Spousal Medical Surcharge
2320339	Hypothetical Tax Withholding
2320340	Pharmacy Payroll Deductions
2320341	Long Term Care Deductions
2320342	Ramsey Grove Usage Fee
2320400	Health Savings Plan
2320401	Apay Co Liab For Hlth Care
2320402	Apay Co Liab For Dental
2320403	Apay Co Prem On Empl Ins
2320405	Apay Scana Inv Plus Plan
2320406	Apay Sc Com Stk Lost Share
2320407	Apay Flex Spending 2008
2320408	Apay Drp Liquidation
2320409	Apay Employ United Way Ded
2320410	Apay Flex Spending-2009
2320500	Apay Addl Rent Pal Ctr
2320505	Apay Flex Spending 2005
2320506	Apay Flex Spending-2010
2320507	Apay Flex Spending 2011
2320508	Apay Flex Spending 2012
2320509	Apay Flex Spending 2013
2320510	Apay Flex Spending 2014
2320511	Apay Flex Spending 2015
2320512	Apay Flex Spending 2016
2320513	Apay Flex Spending Account 201
2320514	Apay Flex Spending 2018
2320600	Apay Psnc Pr Ded Union Dues
2320601	Apay Psnc Pr Ded Bankruptcy
2320602	Apay Psnc Pr Ded Garnishment
2320603	Apay Psnc Pr Ded Cr Union
2320604	Apay Psnc Pr Ded Pac
2320605	Apay Psnc Pr Ded Fed Pac
2320606	Apay Psnc Pr Ded 401k
2320610	Accts Pay - Other Compensation
2320900	Accts Payable Non Tsa
2320910	Accts Payable Tsa
2320920	Accts Payable-scana Ap
2320930	Fac Maint Contracted
2330012	Notes Pay Assoc Co - Scana
2330013	Notes Pay Assoc Co Sceg

2330014	Lt Note Payable - Sh
2340000	Accts Pay-assoc Co
2340001	Apay Assoc Co Svci
2340002	Accts Pay-assoc Co-sps
2340003	Apay Assoc Co Semi
2340004	Apay Assoc Co Psi
2340005	Apay Assoc Co Spr
2340006	Apay Assoc Co Sdc
2340007	Apay Assoc Co Cgtc
2340008	Accts Pay-assoc Co-spg
2340009	Apay Assoc Co Sci
2340010	Apay Assoc Co Scfc
2340011	Apay Assoc Co Servicecare Crcd
2340012	Apay Assoc Co Adv Scana
2340013	Apay Assoc Co Sceg
2340014	Apay Assoc Co Genco
2340015	Ic Ap Scana Resources
2340016	Apay Assoc Co Fh
2340018	Apay Assoc Co Ga
2340019	Apay Assoc Co In
2340021	Apay Assoc Co Svci - Sales Tax
2340028	Apay Assoc Co Psnc
2340029	Apay Assc Co Scana Services
2340035	Apay Assoc Co Scg Pipeline
2340037	Apay Assoc Co - Scana Corp Sec
2340040	Apay Semi Capacity Release
2340041	Apay Semi Secondary Mkt
2340042	Apay Semi Buy/sell
2340043	Apay Semi Storage/asset Mgmt F
2340044	Apay Semi Cost Of Gas
2340045	Apay Schi
2340100	Apay Assoc Co Adv Sceg Fuel
2340101	Apay Assoc Co Genco Billing
2340102	Apay Assc Co Adv Scana Fuel
2340103	Apay Assoc Co-to Genco
2340107	Apay Assoc Co Scpc-hedging
2340112	Advance Payable To Scana
2340113	Payroll Liability - Sce&g
2340116	Apay Assoc Co Adv Fh
2340117	Apay Assoc Co Adv Nu
2340129	Apay Assoc Co - Bonus
2340200	Apay Assoc Co Prosolutions
2340202	Accts Pay Assoc Co-one Step
2340203	Apay Assoc Co Bppb/sceg
2340204	Apay Assoc Co Bppb/psnc
2340205	Apay Assoc Co Bppb/sega

2340206	Accounts Payable Sega
2340229	Advances Payable To Money Pool
2340241	Acct Pay Assoc Co - Serg
2340301	Apay Assoc Co Tax Reserve
2340302	Apay Assc Co Nu Itc & Adit Adj
2340307	Apay Assoc Co - Ga
2340316	Apay Assoc Co It Revenue - Fh
2340329	Ap Assoc Co - Int On Advances
2340335	Apay Assoc Co It Revenue - Scg
2340340	Apay-dominion
2341000	Apay Assoc Co-dri
2341003	Apay P And B Semi
2341007	Apay P And B Scpc
2341028	Apay P And B Psnc
2341029	Inter Co Payable Sc Apay
2341107	Apay Assoc Co Cgtc
2341129	Payable To Assoc Co - P And B
2341206	Apay P And B Semi Georgia
2341207	Fh Apay Assoc Co - Scpc
2342001	Nu Money Pool Advances - Svci
2342003	Nu Money Pool Advances - Semi
2342006	Nu Money Pool Advances-sdc
2342007	Nu Money Pool Advances - Scpc
2342009	Nu Money Pool Advances - Sci
2342010	Nu Money Pool Advances - Scfc
2342012	Nu Money Pool Advances - Sh
2342013	Utility Money Pool Adv - Eg
2342014	Utility Money Pool Adv - Gn
2342028	Money Pool Advances - Psnc
2342035	Nu Money Pool Advances - Scg
2342056	Nu Money Pool Advances - Sega
2343001	Apay Nu Pool Interest Svci
2343003	Apay Nu Pool Interest Semi
2343007	Apay Nu Pool Interest Scpc
2343009	Apay Nu Pool Interest Sci
2343010	Apay Nu Pool Interest Scfc
2343035	Apay Nu Pool Interest Scg
2343056	Apay Nu Pool Interest Sega
2344029	Apay Assoc Co Accrl-sc
2345050	Ap Affiliated Co Synfuel
2345051	Ap Affiliate Co-canadays Refin
2345052	Ap Affiliated Co-cope Refined
2345053	Ap Affiliated Co Nustart Llc

2347000	Apay Assoc Co-drs
2347012	Apay Assoc Co-dpi
2347100	Apay Assoc Co-dri
2350000	Cust Deposits Misc
2350001	Cust Deposits Utility Sales
2350002	Cust Deposits Advances
2350003	Cust Deposits Shipper
2350004	Cust Deposits Bankruptcy
2350005	Transmission Customer Deposits
2350006	Customer Deposits Util Sales-s
2350007	Customer Deposits Util Sales-s
2350117	Apay - H E A T
2350151	Def Cr 2012 Officer Ltb
2360001	Taxes Accr Misc
2360002	Taxes Accr Current Fed Inc
2360003	Taxes Accr State Inc Tax
2360004	Taxes Accr Other Than Inc
2360005	Taxes Accr State Excise
2360006	Taxes Accr Spec Fuels Cng
2360007	Taxes Accr Psnc Fica Bonus Est
2360008	Taxes Accr Fed Excise Tax Cng
2360009	Taxes Accr Pmc Property
2360010	Taxes Accr Franchise
2360011	Federal Usf Fee Payable
2360012	Sc Usf Fee Payable
2360013	Psc Utility Assmt Payable
2360014	Municipal Assn Telecom Tax
2360015	Taxes Accrd Fed Fin 48 (origin
2360016	Taxes Accrd St Fin 48 (origina
2360017	Accr Fed Inc Amended Rtn
2360018	Taxes Accrd Fed Fin 48 (pilot)
2360019	Taxes Accrd St Fin 48 (pilot)
2360020	Taxes Accrued Current Fed Inc-
2360021	Taxes Accrued Fed Fin 48- Aban
2360022	Taxes Accrued St Fin 48- Aband
2360100	Taxes Accr Municipal Prop
2360101	Taxes Accr County Prop
2360102	Taxs Accrued Municipal Prop Sr
2360200	Taxes Accr Other
2360201	Taxes Accr Support Of Psc
2360202	Taxes Accr Self Ins Tax
2360203	Taxes Accr Special Util Lic
2360204	Tax Accr Gross Receipts Tx
2360300	Tax Accr Fed Sbu Estimate
2360301	Tax Accr State Sbu Estimate
2360302	Accrued Taxes - Fica

2360303	Accrued Taxes - Futa
2360304	Accrued Taxes - Suta
2360305	Accrued Payroll Taxes
2360400	Taxes Accr Gss Css Prop Tx
2370000	Interest Accrued Funded Debt
2370001	Int Accr Cust Deposits
2370002	Int Accr 60m Scana Loan
2370003	Int Accr-gn Ind Rev Bonds
2370004	Int Accr-$39.480m 4pct Bonds
2370005	Transmission Interest Accrued
2370006	Int Accr $14.735m 3.625pct Bon
2370007	Int Accrd 400m 4 6 6152043
2370008	Int Accrd 500m 5.1% Bonds Due
2370012	Int Accr Assoc Co - Scana
2370013	Int Accr-quarterly-3yr Agreeme
2370016	Int Accr-int On Cust Deposits
2370017	Int Acrd On Cust Deposits-segr
2370067	Int Accrd $425mm 4.1% Series D
2370100	Int Accr Short Term Notes
2370101	Int Accr Berk Co
2370102	Int Accr 25m 2007
2370103	Int Accr 7 7/8% Note
2370104	Int Accr Med Trm Nt 7/3/00
2370105	Int Accr Natbank Unsec Loan
2370106	Int Accr 30m Trm Ln 1999
2370107	Int Accr 7yr Notes
2370108	Int Accr 60m Term Loan
2370109	Int Accr 15m Term Loan
2370110	Int Accr Trm Ln Spr Mobile
2370111	Int Accr 75m Mtn Due 7 08 03
2370112	Int Accr 115 Mtn Due 2008
2370113	Interest Accrued 50 Mil Mtn
2370114	Int Accrued 400m 6 59%
2370115	Int 6 875% 300m Due 5 15 11
2370116	Int Accrd 6.625% Due 02/01/32
2370117	Int Accr 6% 6/1/97
2370118	Int Accr 6 1/2% 98
2370119	Int Accr 6 875% Mtn 5 15 11
2370120	Int Accr 6 625% 1st Mtg Bond
2370121	Int Accr 5 8% Due 1 15 33
2370122	Int Accr 7 1/4% 02
2370123	Int Accr 10% 2004
2370124	Int Accr 8.75% 2012
2370125	Int Accr 6.99% 2026
2370126	Int Accr 7.45% 2026
2370127	Int Accr 6.625% 2011

2370128	Int Accr 100m Med Term Notes
2370129	Int Accr Bonds Due 11-1-2027
2370130	Int Accrd 5.45% Due 11-1-2032
2370131	Int Accrd Bonds 4.20% Due 11-1
2370132	Int Accr 5 25 100m Bds 3 1 35
2370133	Int Accrd Mtn Due 3-1-2008
2370134	Int Accr 6 25% Series Due 2036
2370135	Int Accrd 250m 6 05% Bonds
2370136	Interest Accrd 250m Mtn Due 4-
2370137	Int Accr Fund Debt 6 5
2370138	Int Accrued - 35 Irb
2370139	Int Accrd - 2009 Fmb
2370140	Int Accrd - 2009 Hybrid Notes
2370141	Int Accr Berk Co Pc 5.95% 2003
2370142	Int Accr Col Dor Co Pc 5.95%
2370143	Int Accrd 40m Sr Fltg Notes 6
2370144	Int Accr 6 54 2020
2370145	Int Accr 250m Fmb Due 02 01 20
2370146	Int Accr 4 59 Due 2021
2370148	Int Accr 4 13% 2046
2370149	Int Accr 4.18% 2047
2370150	Commit Fees Credit Suisse
2370151	Commit Fees Fuji Bank Ltd
2370152	Int Accr 300m Mtl Due 21003
2370158	Int Accrd 6 7% Due 2/1/2011
2370159	Int Acc Fd Dbt 6 1/8 3/1/09
2370160	Int Accrued $250m 6.25% Mtn
2370161	Int Accr $150m Var Rate Notes
2370162	Int Accr 5 3% Dbt Due 5 15 33
2370163	Int Accrd 5 25% Bonds 11 1 18
2370164	200m Mtn Due 11 15 06
2370165	300m Mtn Due 7 15 2002
2370166	Int Acc 7 50% Due 6 15 2005
2370167	Int Accr Med Note 1/13/2003
2370168	Int Accr Dist-trust Pref Secu
2370169	Int Accr Jr Subordntd Debntr
2370170	Int Accr-com Cap Securities
2370171	Int Accr 202m Mtn
2370172	Int Accr 9% Due 06
2370173	Int Accr 155m Trm Ln 8 7/8%
2370174	Int Accr 7 5/8% Due 2023
2370175	Int Accr 6% Due 6/15/00
2370176	Int Accr 7 1/8% 6/15/13
2370177	Int Accr 7 1/2% 6/15/23
2370178	Int Accr 6 1/4% 12/15/03
2370179	Int Accr 100m 7.70% 2004
2370180	Int Accr Med 7/1/98

2370181	Int Accr Car Nat 5 3/4%
2370182	Int Accr Med Trm Nt 7/1/03
2370183	Int Accr 1984 Frfld Co Pc Bnds
2370184	Int Accr Rchlnd Co Pc Bnds
2370185	Int Accr 1986 Frfld Co Pc
2370186	$30m Orgbrg Cty Solid Waste
2370187	Int Accr 1987 Coll Dorch Pc
2370188	Int Accr 7 5/8% 2025
2370189	Commit Fees Un Bk Of Switz
2370190	Commit Fees Citibank
2370191	Int Accr 15m Bnl Trm Ln
2370192	Commit Fees Wachovia Sc
2370193	Commit Fees Citibank
2370194	Commitment Fees Nationsbank
2370195	Commit Fees Ncnb
2370196	Commit Fees Nationsbank
2370197	Int Accr 150 Med Trm Nte Vr
2370198	Commit Fees The Bank Of Ny
2370199	Commit Fees Misc
2370200	Int Accr Orgburg Co Pc Bond
2370201	Int Accr Commit Fee Nuc
2370202	Int Acr Cm Ppr Comm Fee Fosful
2370203	Int Accr Cm Ppr Comm Fees Allw
2370204	Int Accrued 300mil Mtn Due
2370205	Interest Accrued-berk Co 2003
2370206	Int Accr 5 49% Due 2 01 24
2370207	Int Accr - Line Of Credit
2370208	Int Accr 6 06 Due 2018
2370209	Int Accr - Abr Loan
2370210	Interest Accr Swingline Loan
2370211	Int Accr 300m Mtn
2370212	Int Accr 30m Fmb 3 22
2370213	Int Accr 250m Mtn
2370214	Int Accrued 250m Fmb
2370215	Int Accr 4.5% $300m Due 6/1/20
2370300	Interest Accrued-leases
2370514	Accrd Int Lt Note Payable Sh
2370515	Accrd Int Lt Note - Sh Sc
2370516	Accrued Interest Lt Note Payab
2370600	Interest Accrued - Other
2370704	Interest Accrued Transco Refun
2370705	Interest Accrued Sng Refunds
2370800	Interest Accrued Equit Life
2370801	Interest Accrued Amer United

2380000	Common Dividends Declared
2380001	Dividends Declared - R S
2390000	Matured Long Term Debt
2410000	Tax Col Pay Other
2410100	Tax Col Pay Fica
2410101	Tax Col Pay Fica Backup Wth
2410102	Tax Col Pay Federal Income Tax
2410103	Tax Col Pay Sc Tx Non Res Cont
2410104	Tax Col Pay Nc Income Tax
2410105	Tax Col Pay Ga Income Tax
2410106	Tax Col Pay Sc Income Tax
2410107	Tax Col Pay Sc Sls Tx Elec Sls
2410108	Tax Col Pay Sc Sls Tx Ga Sles
2410109	Tax Col Pay Federal Cng
2410110	Tax Col Pay Sc Sales Cng
2410111	Tax Col Pay Sc Sales Tax Other
2410112	Tax Col Pay Sc Use Tax
2410113	Tax Col Pay Nc Use Tax
2410114	Tx Col Pay Whd-div Frgn Stkhld
2410115	Tx Col Pay Whd-div Dom Stkhld
2410116	Tx Col Pay Scusetx Msc Cnst Nu
2410117	Gas Sale Nc
2410118	Tax Col Pay Nc Sales & Use Tax
2410119	Tax Col Pay Interest Income
2410120	Tax Col Pay Nc Sls Tx Ga Sls
2410121	Tax Col Pay White Goods Disp
2410122	Tax Col Pay Al Income Tax
2410123	Sales Tax Billed For Svci
2410124	Tax Col Pay - Ga Sales Tax
2410125	Utility Priv Tax-al
2410126	Sci Nc Utility Use Tax Payable
2410127	Sci-nc Telecom Sales Tax Payab
2410128	Georgia Cnty Excise Tax Payabl
2410129	Tax Col Pay Tn Sales & Use
2410130	Tax Col Pay Tn Local County
2410131	Tax Col Pay Tn Local City
2410200	Tax Col Pay Lost Collctd Other
2410201	Tax Col Pay Lost Coll Pay Use
2410202	Tax Col Pay Delinquent St Tax
2410203	Tax Col Pay Lost Collctd Elec
2410204	Tax Col Pay Lost Collected Gas
2410205	Local Option Billed For Svci
2410207	County Tax Nc
2410210	Tax Col Pay Lost Oth Trans
2410211	Tax Col Pay Lost Oth School
2410212	Tax Col Pay Lost Oth Capitl
2410213	Tx Col Pay Special Municip Tax

2410220	Tax Col Pay Lost Use Transp
2410221	Tax Col Pay Lost Use School
2410222	Tax Col Pay Lost Use Capitl
2410223	Tx Col Pay Municipal Tax
2410224	Tx Col Pay Lost Use Spec Purp
2410225	Tx Col Pay Lost Use Homestead
2410226	Trans Tax Billed For Svci
2410227	School Tax Billed For Svci
2410228	Cap Proj Tax Billed For Svci
2410230	Tax Col Pay Lost Elec Trans
2410231	Tx Col Pay Lost Elec School
2410232	Tx Col Pay Lost Elec Capitl
2410233	Tx Col Pay Special Municip Tax
2410240	Tx Col Pay Lost Gas Transpt
2410241	Tax Col Pay Lost Gas School
2410242	Tax Col Pay Lost Gas Capitl
2410243	Tx Col Pay Special Municip Tax
2410250	Sales Tax Payable- Ga
2410251	Sales Tax Payable- Tennessee
2410252	Sales Tax Payable Mississippi
2410253	Sales Tax Payable Mississippi
2410254	Georgia Cnty Excise Tax Payabl
2410255	Natural Gas Tax Payable - Nc
2410300	2410300 Tax Col Pay Otc Sales
2410301	2410301 Tax Col Pay Lost Otc
2411200	Federal Usf Fee Payable
2411201	Sc Usf Fee Payable
2411202	Psc Utility Assmt Payable
2411203	Municipal Assn Telecom Tax
2420000	Misc Cur And Accr Liab
2420001	Misc Cur & Accr Liab Deposits
2420002	Misc Accr Liab Psnc Pension
2420003	Msc Cur-accr Liab Prmsth - Srs
2420004	Misc Cur & Accr Liab Retainage
2420005	Ferc Annual Hydro Bill
2420006	Franch Agmt Oblig Muni Dev
2420007	Misc Acc Liab Nl Shls
2420008	Misc C&a Liab Loftis Constr
2420009	Misc C&a Liab Con Services
2420010	Misc C&a Liab Bank Acct Rec
2420011	Misc C&a Liab Suppl Ref Pend E
2420012	Misc C&a Liab Suppl Ref Pend A
2420013	Msc Cur&acr Nucl Radwaste Liab
2420014	Misc C&a Liab Co-op Funds
2420015	Misc C&a Liab Reg Fees
2420016	Misc C&a Liab Transp Imbal

2420017	St Cola Franchise Obligations
2420018	Muni Fran Fee Payable Elec
2420019	Credit Balance Customer Ar
2420020	Misc Cur&accr Power Marketing
2420021	Wholesale Fuel Clause Over Col
2420022	Muni Fran Fee Payable Gas
2420023	Cust Contr-short Term Liabilit
2420024	Accrued Liab Hydro Usgs
2420025	Misc Cur And Accr Liab-psnc
2420026	Ibnr - Health Care Accrual
2420027	Misc Cur And Accr-mgp Atty Fee
2420028	Accr Liab - Deferred Rent
2420029	Accrued Liab-psc Settlement
2420030	Accrued Liab - Apt Unit Fees
2420031	Accrued Liab - Delta
2420032	Accrued Liab Emc Non-complete
2420033	Misc Accr Fin 48 Interest
2420034	Misc Cur And Accr-env Rem Cost
2420035	Sc Aiken County Fiber Fund
2420036	Basis Swaps-short Term Liabili
2420037	Accrued Liab-united Way
2420038	Sega - Aiken Lease
2420039	Due To Clinton Ess
2420040	Def Credit Clinton Newberry Ca
2420041	Credit Balance Cust Ar-segr
2420059	Airplane 1 Maint Contract
2420079	Airplane 2 Maint Contract
2420090	Def Rev-elba Diff Invent Sega
2420091	Def Rev-elba Diff Invent Serd
2420092	Semi-1330 Lady St Deferred Ren
2420100	Misc Cur&accr Bonus Stk Match
2420103	Misc Cur&accr Bonus Pyrl Taxes
2420129	Misc Cur & Accr 2017 Emp Bonus
2420130	Misc Curr&accr 2017 St Bonus
2420131	Misc Curr&accr 2015 Officer Lt
2420132	Misc Cur&accr 2015 Restrictd S
2420133	Misc Cur &accr 2018 Emp Bonus
2420134	Misc Cur&accr 2018 St Incent P
2420135	Misc Cur & Accr 2016 Lt Exec P

2420136	Misc Cur&accr 2016 Restrict St
2420137	Misc Cur&accr 2003 St Bonus
2420138	Misc Cur&accr 2004 Emp Bo
2420139	Misc Cur&accr 2004 St Bonu
2420140	Misc Curr&accr 2005 Emp Bonus
2420141	Misc Curr&accr 2005 St Bonus
2420142	Misc Curr&accr 2006 Emp Bonus
2420143	Misc Curr&accr 2006 St Bonus
2420144	Mis Cur&accr 2007 Emp Bonus
2420145	Mis Cur&accr 2007 St Bonus
2420146	Mis Cur&accr 2008 Emp Bonus
2420147	Mis Cur&accr 2008 St Bonus
2420148	Mis Cur&accr 2006 Officer Lt
2420149	Misc Curr & Accr 2009 Emp Bonu
2420150	Accrued Liab -due Greenwood
2420151	Def Cr-cola Hca Call Option
2420152	Def Cr-fpas
2420153	Def Cr-otc Swaps
2420154	Def Cr-guc Financials
2420155	Def Cr-deferred Revenue
2420156	Def Cr-grnwd Call Option Nn
2420157	Def Cr-cnnga Pass Thru
2420158	Def Cr-petal Storage Unreal He
2420159	Def Cr-bp Call Option Nn
2420160	Current Def Cr Guc Option Mtm
2420161	Current Def Cr-cnnga Inventory
2420162	Accrd Liab Ms Property Tax
2420163	Misc Curr & Accr 2009 St Bonus
2420164	Mis Cur & Acc 2007 Offc Long T
2420165	Misc Cur & Accr 2010 Emp Bonus
2420166	Misc Curr & Accr 2010 St Bonus
2420167	Misc Curr & Accr 2008 Officer
2420168	Misc Cur And Accr 2011 Emp Bon
2420169	Misc Cur And Accr 2011 St Bonu
2420170	Unreal Loss On Basis Swaps St
2420171	Mis Cur And Acc 2009 Officer L
2420172	Mis Cur And Accr 2009 Restrctd
2420173	Mis Cur & Accr 2012 Emp Bonus
2420174	Misc Curr & Accr 2012 St Bonus
2420175	Misc Curr & Accr 2010 Officer
2420176	Misc Curr & Accr 2010 Restrict
2420177	Mis Cur & Accr 2013 Emp Bonus
2420178	Misc Curr & Accr 2013 St Bonus
2420179	Misc Curr & Accr 2011 Officer

2420180	Misc Curr & Accr 2011 Restrict
2420181	Mis Cur And Accr 2014 Emp Bonu
2420182	Mis Cur And Accr 2014 St Bonus
2420183	Mis Cur And Accr 2012 Officer
2420184	Mis Cur And Accr 2012 Restrict
2420185	Mis Cur & Accr 2015 Emp Bonus
2420186	Misc Curr & Accr 2015 St Bonus
2420187	Misc Curr & Accr 2013 Officer
2420188	Misc Curr & Accr 2013 Restrict
2420189	Misc Curr & Accr 2016 Emp Bonu
2420190	Misc Curr & Accr 2016 St Bonus
2420191	Misc Curr & Accr 2014 Off Lt B
2420192	Misc Curr & Accr 2014 Rest Stk
2420194	Due To Union Ess
2420195	Due To Union Wss
2420196	Due To Greenwood Cpw
2420197	Due To Greenwood Wss
2420198	Due To Greenwood Petal
2420199	Due To Greenwood Ess
2420200	Accr Liab-petal Storage Mtm Ga
2420202	Accrued Benefits
2420203	Accrued Benefits - Cobra
2420204	Accrued Benefits - Severance
2420205	Ciac Received
2420210	Short Term Benefits Payable
2420211	Due To Tyson-inventory
2420212	Due To Winnsboro-inventory
2420213	Due To Orangeburg-inventory
2420214	Due To Bamburg-inventory
2420215	Due To Bennettsville-inventory
2420220	City Of Wrens Inventory - Mark
2420300	Msc Cur & Accr Liab Accr Pyrll
2420301	Accrue Vacation Carryover
2420302	Misc Cur And Accr Severance
2420303	Deferred Cust Rev-current Port
2420304	Accrued Liab - Commissions
2420305	Def Cr 77 Cust Chrge Revenue
2420306	Def Cr Cost Adjust Factor
2420307	Def Cr Over Under Gm Recovery
2420308	Def Cr Marketer True-up
2420309	Group 2 Overcollection
2420310	Def Cr Over Under Grp 1 Recove

2420400	Transp Shipper Imb And Frq
2420401	Sng Oba Liability Zone 1
2420402	Sng Oba Liability Zone 2
2420403	Transco Oba Liability Zone 1
2420404	Sceg Lng Oba Liability Zone 1
2420405	Est Net Transport Shipper Imb1
2420406	Est Asso Sceg Oba Liability
2420407	Est Sng And Transco Oba Liab
2420408	Est Net Transp Shipper Nonasso
2420409	Est Sceg Oba Carryforward Imb
2420410	Injuries And Damages Reserve
2420420	Tsa Overcollected Yr End July
2420430	Unrealized Frq Yr End 7 07
2420499	Reclass 24204xx To 1420499
2421010	Short Term Benefits Payable
2421200	Federal Usf Fee Payable
2421201	Sc Usf Fee Payable
2421202	Psc Utility Assmt Payable
2421203	Municipal Assn Telecom Tax
2422013	Misc Cur Accrual Incomestatemt
2422017	Misc Cur Accrual Amortized
2422023	Misc Cur Accruals Balancesheet
2430001	Cap Lease Obligation-current
2430002	Cap Lease Obligation-current G
2430003	Cap Lease Obligation-current C
2430088	Cap Lease Current Monroe Pipe
2440001	Derivative Instr Liab-pm Swaps
2440002	Der Liab 35m Sifma 234
2440003	Der Liab U S Bank #228
2440004	Der Liab W/f #226
2440005	Der Liab Jpm #220
2440006	Der Liab Jpm #230
2440007	Der Liab U S Bank #219
2440008	Der Liab Td Bank #221
2440009	Der Liab Mizuho #225
2440010	Der Liab Ubs #232
2440011	Der Liab - Union Bank#233
2440012	Der Liab - Ubs#231
2440013	Der Liab - Cs#218
2440014	Der Liab - Cs#229
2440015	Der Liab Ubs #240
2440016	Der Liab U S Bank #239
2440017	Der Liab Mizuho #238
2440018	Der Liab Td Bank #241

2440019	Der Liab-boa #222
2440020	Der Liab-wells Fargo #217
2440021	Der Liab-morgan Stanley #227
2440022	Der Liab U S Bank #236
2440023	Der Liab Ubs #237
2440029	Der Liab Boa #249
2440030	Der Liab Bqa #250
2440031	Der Liab Morgan Stanley #251
2440032	Der Liab Jpm #242
2440033	Der Liab Mizuho #243
2440034	Der Liab Ubs #244
2440035	Der Liab Wf #245
2440036	Der Liab Td Bank #246
2440037	Der Liab-us Bank #247
2440038	Der Liab Ubs #252
2440039	Der Liab Morgan Stanley #253
2440040	Der Liab U S Bank #254
2440041	Der Liab Union Bank #255
2440042	Der Liab Morgan Stanley #256
2440043	Der Liab W/f #257
2440044	Der Liab Bank Of America #258
244029	Der Liab Boa #249
2450000	Scpc Gas Hedging Gains - Net
2450001	Psnc Hedges - Liability
2450002	Market Value - Open Positions
2450003	Derivative Ins - 2007 Fss
2450004	Dil Hedges-36.4m Fss
2450005	Dil Hedges-150m Fss
2450006	Der Liab 100m Mizuho Swap
2450007	Der Liab 100m Boa Swap
2450008	Der Liab 100m Wf Swap
2450009	Der Liab 125m Swap Wf
2450010	Der Liab-125m Swap Boa
2450011	Der Liab-100m-swap-csfb
2450012	Der Liab 125m Boa Swap
2450013	Der Liab 125m Bank Of New York
2450014	Der Liab - 90m Swap - Csfb
2450015	Der Liab - 110m Campus Swaps
2450016	Der Liab - 36 4m Sifma Swap
2450017	Der Liab - 35m Sifma Swap
2450018	Der Liab - 75m Swap Boa
2450019	Der Liab - 75m Swap Wf
2450199	Derivative Instruments Liab
2470157	Cust Contrs-short Term Liabili
2530000	Misc Deferred Credits
2530001	Def Cr Pal Ctr Refinance

2530002	Def Cr Cashiers Overage
2530003	Def Cr Agents Overage
2530004	Def Cr Unclaimed Wages
2530005	Def Cr Mgp Enviro Cleanup
2530006	Def Cr Flyover I 126
2530007	Def Cr M And S Usc Tax
2530008	Def Cr Oth Enviro Cleanup
2530009	Def Cr Unredeem Tran Coupons
2530010	Def Cr Pal Ctr Lease Pmt
2530011	Def Cr Nuclear Refueling
2530012	Def Cr Tran Umta Grant
2530013	Def Cr Treas A Account
2530014	Def Cr 1 For 1 Interchange
2530015	Def Cr Accr Decommissioning
2530016	Def Cr Abandon Prop Rptd To St
2530017	Def Cr Resource Enhance
2530018	Misc Deferred Credits - Misc
2530019	Def Cr Aband Prop Pref Redemp
2530020	Def Cr Escheat Pay Cks
2530021	Def Cr Storm Dam. Res-elec
2530022	Def Cr Storm Dam. Res-tran
2530023	Def Cr United Way Contrib
2530024	Def Cr Coal Options
2530025	Def Cr Georgia Customer Adj
2530026	Misc Def Cr M C Leasing
2530027	Def Cr Unearn Int Third
2530028	Def Cr Accr Dividend Equ
2530029	Def Cr Stator Bars Commitment
2530030	Derivative Instruments - Ncemc
2530031	Deferred Cr Psnc Ciac
2530032	Misc Deferred Credits-earnest
2530033	Cola Energy Trans Credits
2530034	Otarre Wetland Remediation
2530035	Deferred Credits - Confed Life
2530036	Def Cr-right Of Way-checking A
2530037	Refund Of Franchise Fees
2530038	Chas Garage Pre-pymt
2530039	Telephone Pole Attachments
2530040	Grwood Energy Credits&discount
2530041	Interconnect Studies Deposit
2530042	Def Cr-2008 Swap 20m-wachovia

2530043	Def Cr Warburg Swap Fair Value
2530044	Fed Income Tax Liability
2530045	Unearned Rev - Street Lights
2530046	Calpine Reserve
2530047	Oth Def Cr Nustart-psa
2530048	Oth Def Cr Apog Llc-psa
2530049	Def Cr - 2007 Swap-wachovia
2530050	Apay Directors Endowment
2530051	Ap Sh Serp Fas 158
2530052	Def Credit-mgp Atty Fees
2530053	Santee River Basin Accord
2530054	Deferred Cust Rev-lt Portion
2530055	Transcontinental Gas Refunds
2530056	Southern Natural Gas Refunds
2530057	Reductions Owed The Wacog
2530058	Dr Cr Marketer True-up
2530059	Def Cr - 2010 Swap - Boa
2530060	Def Cr-hvac Interest Income
2530061	Def Cr Lt - Rent
2530062	Def Cr - Cost Adj Factor
2530063	Df Cr Over Under Gross Margin
2530064	Oth Def Credits- 36 4 Fss
2530065	City Of Columbia Nssf
2530066	Other Def Credits - 150m Swap
2530067	Def Cr - 2010 Swap - Wachovia
2530068	Def Cr - 2010 Swap - Mizhuo
2530069	Def Cr - Pref Stk Redeem 2009
2530070	Intercon Stdy Dep 3rd Pty
2530071	Transmission Study Dep - Nu
2530072	Oth Def Cr - 100 Fss-csfb
2530073	Oth Def Cr - Boa Swap
2530074	Oth Def Cr - Bank Of Ny Swap
2530075	Oth Def Cr Boa Swap
2530076	Oth Def Cr Wells Fargo Swap
2530077	Due To Greenwood-petal
2530078	Oth Def Cr - 35m Sifma Swap
2530079	Def Cr Long Term Pledges
2530080	Def Cr- Env Remediation Costs
2530081	Der Liab Union Bank #233
2530082	Der Liab Ubs #231
2530083	Der Liab Cs #229
2530084	Der Liab Cs #218
2530085	Der Liab W/f #217
2530086	Der Liab Ms #227
2530087	Der Liab Boa #222
2530088	Def Cr Cap Lease Liab Monroe

2530089	Der Liab Us Bank #236
2530090	Der Liab Ubs #237
2530091	Der Liab $35m Sifma Swap
2530092	Cgt - Dominion
2530093	Sci - Spirit
2530094	Atlanta Falcon Sponsorship
2530095	Def Cr Contingency Reserve Sci
2530096	Der Liab-jpm-#242
2530097	Der Liab-mizuho-#243
2530098	Der Liab-ubs-#244
2530099	Der Liab-wf-#245
2530100	Def Cr 16 Off Lt Bonus
2530101	Def Cr 16 Off Rest Stock Lt Bo
2530102	Def Cr Treas A Acct-segr
2530103	Bonus Payroll Taxes
2530104	Def Cr 98 Bonus Payroll Taxes
2530107	Def Cr 95 Off Lt Bonus
2530108	Psnc Common Div Stale Dated
2530109	Def Cr Def Compensation
2530110	Def Cr Def Compen Interest
2530111	Def Cr Void Com Stk Dividends
2530112	Def Cr Scana Dir Endowment
2530113	Def Cr 2014 Officer Long Term
2530114	Def Cr 2014 Officer Restrict S
2530115	Def Cr 2015 Officer Long Term
2530116	Def Cr 2015 Officr Restrict St
2530117	Def Cr 2017 Officer Long Term
2530118	Def Cr 2017 Off Restricted Stk
2530119	Def Cr 2018 Officer Lt Bonus
2530120	Def Cr 2018 Offcr Restrict Stk
2530121	Def Cr 99 Off Lt Bonus
2530122	Residential Mktg Bonus
2530123	Def Cr 2000 Emp Bonus
2530124	Def Cr 2000 Off Shrt Trm Bn
2530125	Def Cr 2000 Off Long Trm Bn
2530126	Def Cr Transit Emp Bonus
2530127	Def Cr 2001 Emp Bonus
2530128	Def Cr 2001 Off St Bonus
2530129	Def Cr 2001 Off Lt Plan
2530130	Def Cr Psnc Accr Severance
2530131	Def Cr Psnc Comp Out Cash
2530132	Def Cr Psnc Retirement Outs
2530133	Def Cr 2002 Emp Bonus
2530134	Def Cr 2002 St Bonus
2530135	Def Cr 2002 Lt Bonus
2530136	Def Cr 2003 Employ Bonus
2530137	Def Cr 2003 St Incentive Bonus

2530138	Def Credit 2003 Officer Lt
2530139	Def Credit 2004 Officer Lt
2530140	Def Credit 2005 Officer Lt Bon
2530141	Deferred Credit - Lock 2005
2530142	Def Credit 2006 Officer Lt Bon
2530143	Def Cr 2007 Officer Lt Bonus
2530144	Def Cr 2008 Officer Lt Bonus
2530145	Def Cr 2009 Officer Long Term
2530146	Def Cr 2010 Officer Long Term
2530147	Def Cr 2009 Officer Restr Stk
2530148	Def Cr 2010 Officer Restr Stk
2530149	Def Cr 2011 Officer Long Term
2530150	Def Cr 2011 Officer Restrictd
2530151	Def Cr 2012 Officer Long Term
2530152	Def Cr 2012 Officer Restricted
2530153	Def Cr 2013 Officer Long Term
2530154	Def Cr 2013 Officer Restricted
2530155	Due To Clinton Ess
2530156	Basis Swaps - Long Term Liabil
2530157	Cust Contr-long Term Liability
2530158	Semi-1330 Lady St Deferred Ren
2530159	Ap Fin 48 Int Exp
2530160	Der Liab Union Bank #260
2530161	Der Liab - Tdb #261
2530162	Der Liab Rbc #262
2530163	Der Liab - Cs #263
2530180	Cpw Inventory Due-greenwood
2530181	Sega - Aiken Lease
2530182	Long Term-grnwd Option Acrl
2530183	Due To Cnnga-inventory
2530184	Due To Odpu-inventory
2530185	Due To Bennettsville-inventory
2530186	Due To Bamberg-inventory
2530187	Due To Winnsboro-inventory
2530188	Due To Tyson-inventory
2530189	Unrealized Loss Otc Swaps
2530190	Bp Call Option Nn-lt
2530191	Unrealized Loss Guc Lt
2530192	Due To Greenwood-ess Inventory
2530193	Due To Greenwood-wss Inventory
2530194	Due To Union - Ess Inventory
2530195	Due To Union - Wss Inventory

2530196	Def Cr Unearn Int Third
2530197	Unreal Loss On Basis Swaps Lt
2530198	Ingleside Future Ciac Obligati
2530199	Cainhoy Future Ciac Obligation
2530200	Def Cr Cbl Pole Attach Rentals
2530201	Def Cr Gas Water Heater
2530202	Def Cr Home Value Visit
2530203	Def Cr Sidewalk Lighting
2530204	Def Cr Leases
2530205	Def Cr Gatu
2530206	Def Cr Lawn Mower
2530207	Def Cr Gas Heat And Cool
2530208	Def Cr Gas Appliances
2530209	Def Cr Food Service
2530210	Def Cr Commer Water Heater
2530211	Internal Wtr Htr Deferred Int
2530212	Def Cr Revenue
2530213	Def Cr Secondary Market Fees
2530214	Def Cr Service Pole
2530215	Def Cr Elec Appli Financing
2530216	Def Cr Unearned Sec Mkt Fees
2530217	Def Cr Emergency Repair
2530218	Def Cr Contribution In Aid
2530219	Def Cr Arms Lease
2530220	Def Cr Chas Garage
2530221	Deferred Cr Sads And Iaqs
2530222	Def Cr Ferc Settlement
2530223	Def Cr Srs Substation Markup
2530224	Trans Payable-twn Of Blythewoo
2530225	Dr Sci Info Ave #1 Char Rack L
2530226	Dr Sci Pmn Yemasee Grnd Ls
2530227	Dr Sci Pmn Yemasee Rack Ls
2530228	Dr Sci Pmn St George Grnd Ls
2530229	Dr Sci Pbt Safe Cu Lex Ind Fbr
2530230	Dr Sci Pbt 120 Hwy 378 Fbr Ls
2530231	Dr Sci Pbt Lextn Medical Fbr L
2530232	Dr Sci Pbt Midway 378 Fbr Ls
2530233	Dr Sci Sc Oir Sumtr Sled Fbr L
2530234	Dr Sci Att Generator Connect
2530235	Dr Sci Bcbs Rts 1-8 Annl Maint
2530236	Dr Sci Roper Fiber Relo
2530237	Dr Sci Home Tel 74 Dark Fbr Ls
2530238	Dr Sci Home 74 Dk Fbr Anl Mnt
2530239	Dr Sci Home Tel 96 Dark Fbr Ls
2530240	Dr Sci Home 96drk Fbr Anl Mnt
2530241	Dr Sci Sclr/musc Dark Fbr Ls

2530242	Dr Sci Frc 4 Fbr Sville Anl Mn
2530243	Dr Sci Srs Aiken 4 Dark Fbr Ls
2530244	Dr Sci-srs-10g Backbone Fbr Ls
2530245	Dr-sci-culr-dark Fbr Ls
2530246	Dr Sci Usc Bull St Fiber Relo
2530247	Dr Sci Verizon Coopers Creek
2530248	Dr-sci-choate Cnstr-dark Fbr L
2530249	Dr-sci-jbc-egan Bros Fbr Ls
2530250	Dr-sci-aiken Cty Fbr Connect
2530251	Dr-sci-cgt-shakespre Rd Twr Ls
2530252	Dr Sci Verizon Green South
2530253	Dr-sci-vftt-rosewood
2530254	Dr-sci-vftt-assembly St
2530255	Dr-sci-vftt-cayce Carolinas
2530256	Dr-sci-vftt-claire Towers
2530257	Dr-sci-vftt-highway 126
2530258	Dr-sci-vftt-highway 555
2530259	Dr-sci-vftt-riverfront Relo
2530260	Dr-sci-vftt-south Lexington
2530261	Dr-sci-vftt-woodland Hills
2530262	Dr-sci-vftt-wingard
2530263	Dr-sci-vftt-forest Acres
2530264	Dr-sci-vftt-hunley
2530265	Dr-sci-vftt-hamlin
2530266	Dr-sci-vftt-sawyer
2530267	Dr-sci-vftt-sgt Jasper
2530268	Dr-sci-vftt-snowden
2530269	Dr-sci-vftt-battery Park
2530270	Dr-sci-vftt-bees Ferry
2530271	Dr-sci-vftt-brittle Bank
2530272	Dr-sci-vftt-cypress Gardens
2530273	Dr-sci-vftt-city Market
2530274	Dr-sci-vftt-avondalet
2530275	Dr-sci-vftt-cross Country
2530276	Dr-sci-vftt-florida
2530277	Dr-sci-vftt-francis Marion
2530278	Dr-sci-vftt-columbia College
2530279	Dr-sci-vftt-wando Warrior
2530280	Dr-sci-vftt-scana Hq Cayce
2530281	Dr-sci-vftt-howard Street
2530282	Dr-sci-vftt-rosewood Upgrd
2530283	Dr-sci-vftt-n Rhett Goose Crk
2530284	Dr-sci-vftt-little Bull Bozard
2530285	Dr-sci-vftt-chas Airbs Wtr Twr
2530286	Dr-sci-vftt-billboard Vine St
2530287	Dr-sci-knolgy-darby-mt Pls Fbr
2530288	Dr Sci Aiken County Lt Storage

2530289	Dr Sci Aiken Cnty Lt Str Maint
2530290	Dr Sci Pbt Lex Med Anl Maint
2530291	Dr Sci Pbt Hwy 1 Safe Anl Main
2530292	Dr Sci Pbt I20 378 Anl Maint
2530293	Dr Sci Knolgy Darby Mt Pls Mnt
2530294	Dc-sci-core Campus-tower
2530295	Dc Sci Lk Mury Grnd Ls Tower
2530296	Dc Sci 1401 Main Fiber
2530297	Dr Musc Sclr Dk Fiber Ls
2530298	Dc-sci-core Campus-fiber
2530299	Dc Sci Cherokee Springs Gl
2530300	Def Cr Kerp Liab Active
2530301	Def Cr Kerp Liab Retired
2530302	Def Cr Kerp Loans Csv
2530303	Def Cr Kerp Accr Interest
2530304	Other Defrrd Credits-erip 1989
2530305	Def Cr 1990 Serp Benefits
2530306	Def Cr Oer Erip
2530307	Def Cr Opeb
2530308	Def Cr Srf
2530309	Def Cr Spplmntl Exec Retrmnt
2530310	Def Cr Kerp Fica W/h
2530311	Psnc Deferred Taxes Opeb
2530312	Df Cr Acc Dvd Sca Psnc Merg
2530313	Def Cr Deferred Compen Stk
2530314	Def Cr Consulting Fees
2530315	Def Cr Deferred Compen Cash
2530316	Def Cr Svdp
2530317	Deferred Credits - Ltd
2530318	Def Cr Supplemental Retirement
2530319	Def Cr Opeb
2530320	Def Cr - Opeb Contra
2530321	Def Cr Serp Fica Wh
2530322	Def Cr Apay Lt Disabil Sfas112
2530323	Oth Def Cr Ubs Swap #252
2530324	Oth Def Cr Boa Swap #249
2530325	Def Credit-other Compensation
2530326	Oth Def Cr Morgan Stanley #251
2530327	Oth Def Cr Boa Swap #250
2530328	Oth Def Cr Us Bank #254
2530329	Oth Def Cr Union Bank #255
2530330	Oth Def Cr Ms Swap #253
2530331	Pine Hill Transactions
2530332	Der Liab-m Stanley #256

2530333	Der Liab Wf #257
2530334	Der Liab Boa Swap #258
2530350	Dr-sci-spirit-oburg Dist 3 Fib
2530351	Dr Sci Verizon Camden Grace
2530352	Dr Sci Verizon Gray's Chapel
2530353	Dr-sci-verizon Lake Robinson
2530354	Dr Sci Egan Bros Dk Fiber Lic
2530355	Dr-sci-knology-anl Mnt-drk Fbr
2530356	Dr Sci Verizon Hunting Camp
2530357	Dr Sci Verizon Winding Bluff
2530358	Dr Sci Verizon Craggie Tower
2530359	Dr Sci Verizon 87n Tower
2530360	Dr Sci Verizon Cherokee Spring
2530361	Dr Sci Verizon Dunlop
2530362	Lt Cnnga Option Accrual
2530363	Atlanta Falcons Suite
2530400	Def Cr Pal Ctr Refinancing
2530401	Enviromental Settlement
2530402	Def Credits Ge Capital
2530429	Def Cr Unearn Int Gas Logs
2530430	Def Cr Unearn Int Propane Conv
2530500	Pension Obligation
2530501	Apay Pensions Sapp
2530503	Apay Pensions Semi
2530507	Apay Pensions Scpc
2530509	Apay Pensions Sci
2530512	Def Cr Apay Sh -pensions
2530513	Apay Pension From Subs
2530514	Ap Sh Pension Fas 158
2530526	Apay Pension Sega
2530528	Apay Pensions Psnc
2530530	Apay Pensions Ssec
2530532	Apay Pensions Psa
2530533	Apay Pension Psa Fas 158
2530605	Receipts Owed To Pine Island(p
2530606	Receipts Owed To Sand Dunes(sd
2530607	Receipts Owed To Misty Lake(ml
2530608	Receipts Owed To Sand Dunes(si
2530612	Apay Sh - Opeb
2530613	Apay Opeb From Subs
2530614	Ap Sh Opeb Fas 158
2530712	Def Cr Apay Lt Disabil Sfas112

2530713	Apay Def Taxes Pen Inc Psnc
2530812	Def Cr Apay Lt Disability
2530813	Def Cr Lt Disability
2530911	Def Cr Burton Ins Proceeds
2530912	Def Cr Apay-sh-erip
2530913	Csv Due To Eg For Dir Endow
2530915	Sh Apay To Eg - Edcp Funding
2530928	Csv Due To Psnc For Dir Endow
2530929	Def Cr - Microsoft Enterprise
2530930	Def Cr - Sea
2530931	Def Cr - Ca - Mf Upgrade
2530932	Microsoft - Eci
2530933	Deferred Liability - Ibm Ela
2531010	Longterm Benefits Payable
2534001	Transcontinental Gas Refunds
2535001	Southern Natural Gas Refunds
2536000	Reductions Owed The Wacog
2537000	Deferred Revenue-facility Char
2538005	Receipts Owed To Pine Island(p
2538006	Receipts Owed To Sand Dunes(sd
2538007	Receipts Owed To Misty Lake(ml
2538008	Receipts Owed To Sand Dunes(si
2539002	Def Cr Cashrs Ovrge Seb Cis
2540000	Reg Liab Fuel Clause Ovrcllctn
2540001	Reg Liability Pga Unbilled
2540002	Regulatory Liab Miscellane
2540003	Reg Liab Psnc Def Refunds
2540004	Reg Liab Estimated L&u Trueup
2540005	Deferred Hedge Gains
2540006	Reg Liab - Storm Damage
2540007	Reg Liab - In Storm Damage
2540008	Reg Liab - Ncemc Contract
2540009	Reg Liabil Major Maint Accrual
2540010	Reg Liabil Mmj Accrual Interes
2540011	Oth Reg Liab Nuclear Refueling
2540012	Oth Reg Liab - Pga -unbilled
2540013	Reg Liab Elec - Unbilled Fuel
2540014	Hedges - Liability
2540015	Reg Liab Est Sec Mkt Cust
2540016	Reg Liab Res Commondity Over
2540017	Reg Liab Com Commodity Over
2540018	Reg Liab Ind Commodity Over
2540019	Reg Liab Res Demand Over

2540020	Reg Liab Com Demand Over
2540021	Reg Liab Ind Demand Over
2540022	Hedges-liability
2540023	Otc Swaps- Liability
2540024	Reg Liab - Ncuc Expenses
2540025	Regulatory Liability - Calpine
2540026	Aro Regulatory Liability
2540027	Other Reg Liab-36.4m Fss
2540028	Other Reg Liab-150m Fss
2540029	Reg Liab - Pga Unbilled
2540030	Other Reg And Liab 150m Lock
2540031	Reg Liab Conservation Programs
2540032	2010 Electric Weather Adjust
2540033	Reg Liab Ciac Refunds
2540034	Oth Reg Liab 75m Jpm
2540035	Oth Reg Liab 75m Db
2540036	Oth Reg Liab 75m Ubs
2540037	Oth Reg Liab 75m Bac
2540038	Reg Liab $50m 3.635% Us Bank
2540039	Reg Liab $50m 3.625% Ubs
2540040	Fuel Clause Wholesale Overcoll
2540041	Reg Liab Reagent Over Collect
2540042	Other Reg Liability-35 Fss
2540043	Other Reg Liab-credit Suisse
2540044	Other Reg Liability 80m Swap U
2540045	Other Reg Liability 80m Swap M
2540046	Other Reg Liability 90m Swap C
2540047	Other Reg Liab - 90m Swap Ubs
2540048	Other Reg Liab - 80m Swap Wf
2540049	Other Reg Liab - 80m Swap Boa
2540050	Other Reg Liab - 90m Swap Mizu
2540051	Other Reg Liab - 80m Swap Ms
2540052	Other Reg Liab - 80m Swap Db
2540053	Other Reg Liab - 100m Swap Cs
2540054	Other Reg Liab - 100m Swap Jpm
2540055	Reg Liab 50m U S Bank 228
2540056	Reg Liab 100m Wf Link 226
2540057	Reg Liab 50m Jpm 220
2540058	Reg Liab 100m Jpm 230
2540059	Other Reg Liab-boa Swap-2010
2540060	Reg Liab Residental Cut
2540061	Reg Liab Commercial Cut

2540062	Reg Liab U S Bank 50m 219
2540063	Reg Liab 100m Tdb 221
2540064	Reg Liab 100m Mizuho 225
2540065	Reg Liab 50m Ubs 232
2540066	Reg Liab 100m Union Bank 233
2540067	Other Reg Liab-wachovia
2540068	Reg Liab 50m Ubs 231
2540069	Reg Liab Cs 100m 218
2540070	Reg Liab Cs 100m 229
2540071	Reg Liab Wf 100m 217
2540072	Reg Liab Ms 100m 227
2540073	Reg Liab 100m Boa 222
2540074	Reg Liab 35m Sifma 234
2540075	Other Reg Liab-db Jpm Ubs Boa
2540076	Reg Liab $100m Mizuho $500m De
2540077	Reg Liab $50m Ubs $500m Debt
2540078	Reg Liab-morgan Stanley #256
2540079	Reg Liab - Boa #258
2540080	Equity Dsm Residential Carry C
2540081	Equity Dsm Com/ind Carry Costs
2540082	Reg Liab - Wf #257
2540083	Reg Liab Swap#260 Mub
2540084	Reg Liab Swap#261 Tdb
2540085	Reg Liab Swap#262 Rbc
2540086	Reg Liab Swap#263 Credit Suiss
2540087	Reg Liab Swap#265 Morgan Stanl
2540088	Reg Liab Swap #266 Boa
2540089	Winnsboro Fuel Overcollected
2540090	Orangeburg Fuel Over Collected
2540091	Reg Liab Jpm Swap #242
2540092	Reg Liab Mizuho Swap #243
2540093	Reg Liab Ubs Swap #244
2540094	Reg Liab Wf Swap #245
2540095	Reg Liab Td Bank Swap #246
2540096	Reg Liab Us Bank Swap #247
2540097	Reg Liab - Imt(int Mgmt Trkr)
2540098	Reg Liab - Enviromental Remedi
2540099	Reg Liab- Def Rev Fed Tax
2540100	Reg Liab So2 Arp
2540101	Reg Liab S02 Csapr
2540110	Reg Liab State Adit Transit
2540116	Reg Liab-ip Fees Collected

2540117	Reg Liab-srs Fees Collected
2540118	Reg Liab-synfuel Fuel Disc Def
2540119	Reg Liab-synfuel Oper Loss-cdy
2540120	Reg Liab-synfuel Oper Loss-wat
2540121	St Adit Coaltch Op-wat
2540122	Fed Adit Coaltech-wat
2540123	Fed Syn Tax Cr-wat
2540124	St Adit Coaltch Op-cdy
2540125	Fed Adit Coaltech-cdy
2540126	Fed Syn Tax Cr-cdy
2540127	Oth Reg Liabilities-2006 Lock
2540130	Reg Liab - Cut Rate 101
2540131	Reg Liab - Cut Rate 102
2540132	Reg Liab - Cut Rate 125
2540133	Reg Liab - Cut Rate 127
2540134	Reg Liab - Cut Rate 140
2540140	Rg Liab-toshiba Settl Proceeds
2540150	Reg Liab Nox Ozone Cair
2540151	Reg Liab Nox Ozone Csapr
2540160	Reg Liab Nox Annual Cair
2540161	Reg Liab Nox Annual Csapr
2540162	Elec Pension Rider Overrcvry
2540200	Reg Liab Fed Adit Gas
2540201	Reg Liab Fed Adit Transit
2540202	Reg Liab Itc Federal Elec
2540203	Reg Liab Itc Fed Gas
2540204	Reg Liab Itc Fed Coach
2540205	Reg Liab Itc State Electric
2540206	Reg Liab Itc State Gas
2540207	Reg Liab Itc State Coach
2540208	Reg Liab Psnc Excess Def Tx
2540209	Reg Liab-psnc Excess Dit Fed O
2540210	Reg Liab - Psnc Excess Dit Fed
2540211	Reg Liab - Psnc Excess Dit St
2540212	Reg Liab-psnc Excess Dit 2.5%
2540220	State - Adit - Gas
2540250	Reg Liab Fed Tax Rate Change N
2540251	Reg Liab Fed Tax Rate Change A
2540252	Reg Liab Elec Fed Tax Rt Chg B
2540255	Reg Liab St Adit Elec
2540256	Reg Liab St Adit Gas
2540257	Reg Liab Fed Adit Elec
2540258	Reg Liab Fed Adit Gas
2540260	Reg Liab Gas Fed Tax Rate Chg
2540262	Reg Liab Gas Fed Tax Rt Chg Ba
2540303	Reg Liab - It Revenue

2540318	Reg Liab Associated Co Gas
2540401	Frq Regulatory Liability
2540402	It Revenue Shared Non Assoc Co
2540403	Reg Liab Assoc Co It Revenue
2540404	Estimated Tda-shippers
2540405	Tda-trans Shipper Imbalance
2540406	Estimated Tda-oba
2540407	Penalty Revenue Liab Non Assoc
2540408	Tda-oba
2540410	Tda Frq
2540412	It Revenue Shared Asso - Sceg
2540417	Penalty Revenue Liab Asso-sceg
2540420	Tda Overcollected Yr End July
2540422	It Revenue Shared Assoc - Semi
2540425	Cec Settlement Regulatory Liab
2540426	Ft Settlement Regulatory Liabi
2540427	Penalty Revenue Liab Asso-semi
2540428	Deferred Revenue - Facility Ch
2540430	Unrealized Frq Overcollct 7 07
2540499	Frq Regulatory Reclass To 1823
2550000	Accum Def Itc
2550001	Accum Def Itc State Elec
2550002	Accum Def Itc State Gas
2550003	Acc Def Itc Fed Elec
2550004	Acc Def Itc Fed Nucl
2550005	Acc Def Itc Fed Gas
2550006	Acc Def Itc Fed Coach
2570000	Unam Gain On Reacq Debt
2570103	Unam Gain 5% Gold Bnds 99
2570104	Unam Gain 5.95% 8/1/2003
2810000	Adit Accel Amort Property
2810001	Accel Amort State
2820000	Accum Def Income Tax Prior Yr
2820001	Adit Fed Elec Liberal Depr
2820002	Adit Fed Nuc Liberal Depr
2820003	Adit Fed Gas Liberal Depr
2820004	Adit Fed Btl Depr
2820005	Adit St Elec Liberal Depr
2820006	Adit St Nuc Liberal Depr
2820007	Adit St Gas Liberal Depr
2820008	Adit St Btl Depr
2820009	Adit Fed Parr & Hagood Demltn
2820010	Adit St Parr & Hagood Demltn

2820011	Adit Fed Elec Intangibles
2820012	Adit Fed Gas Intangibles
2820013	Adit Fed Tran Intangibles
2820014	Adit St Elec Intangibles
2820015	Adit St Gas Intangibles
2820016	Adit St Tran Intangibles
2820017	Adit Fed Elec Plt Fasb 109
2820018	Adit Fed Gas Plt Fasb 109
2820019	Adit Fed Tran Plt Fasb 109
2820020	Adit St Elec Plt Fasb 109
2820021	Adit St Gas Plt Fasb 109
2820022	Adit St Tran Plt Fasb 109
2820023	Adit Fed Elec Res And Exp
2820024	Adit Fed Gas Res And Exp
2820025	Adit Fed Tran Res And Exp
2820026	Adit St Elec Res And Exp
2820027	Adit St Gas Res And Exp
2820028	Adit St Nucl Stm Gen Remov
2820029	Adit Fed Elec Basis Dif
2820030	Adit Fed New Nucl Int Dif
2820031	Adit Fed Gas Basis Dif
2820032	Adit St Depr Scana Gas
2820033	Adit St Elec Basis Dif
2820034	Adit St New Nucl Int Dif
2820035	Adit St Gas Basis Dif
2820036	Adit St Tran Basis Dif
2820037	Adit Fed Stm Gen Removal
2820038	Adit Fed Int Emis Allowances
2820039	Adit St Emis Allowances
2820040	Accum Def Federal Income Tax
2820041	Accum Def State Income Tax
2820042	Adit Fed Depr Scana Gas
2820043	Adit Fed Bas Diff Gas
2820044	Adit State Elec Removal Cost
2820045	Adit State Gas Removal Cost
2820046	Adit Fed Elec Removal Cost
2820047	Adit Fed Gas Removal Cost
2820048	Accum Def Inc Tax Fed Cogen
2820049	Accum Def Inc Tax St Cogen
2820050	Adit Fed Psnc Integration
2820051	Adit State Psnc Integration
2820052	Adit Reg Cr Excess Adj
2820053	Adit Reg Dr Deficient
2820054	Adit Reg Cr Excess State
2820055	Adit Reg Dr Deficient
2820056	Adit Ratepayer Refund/recvy
2820057	Adit Fed Def Inc Tax

2820058	Adit Other Federal
2820059	Adit State Def Inc Tax
2820060	Adit Other State
2820061	Adit - Fed - Line Pack
2820062	Fed Psnc Cardinal Liberal Depr
2820063	St Psnc Cardinal Liberal Depr
2820064	Adit-state - Line Pack
2820065	Adit Fed Fin 48 (original Clai
2820066	Adit St Fin 48 (original Claim
2820067	Adit Fin 48 Int
2820068	Adit Fed Repairs Project
2820069	Adit State Repairs Project
2820070	Adit Fed Reg Pollution Control
2820071	Adit St Reg Pollution Control
2820072	Adit Fed Wateree Scrubber
2820073	Adit St Wateree Scrubber
2820074	Adit Fed Owips
2820075	Adit St Owips
2820076	Adit Fed Net Elec Arc
2820077	Adit St Net Elec Arc
2820078	Adit Fed Net Elec Nucl Arc
2820079	Adit St Net Elec Nucl Arc
2820080	Adit Fed Net Gas Arc
2820081	Adit St Net Gas Arc
2820082	Adit Fed No2 Emission Allowanc
2820083	Adit St No2 Emission Allowance
2820084	Adit Fed Nnd Basis Diff (orig
2820085	Adit St Nnd Basis Diff (orig C
2820086	Adit Fed Nnd Rate Base (orig C
2820087	Adit St Nnd Rate Base (orig Cl
2820088	Adit Fed Nnd 174 Rate Base (or
2820089	Adit St Nnd 174 Rate Base (ori
2820090	Powertax Adj-fed
2820091	Powertax Adj-fed Gas
2820092	Powertax Adj-state
2820093	Powertax Adj-state Gas
2820094	Powertax Adj-fed Nonutility
2820095	Powertax Adj-state Nonutility
2820100	Adit St Elec Lake Murray Dam
2820101	Adit Fed Nnd Basis Diff (pilot
2820102	Adit St Nnd Basis Diff (pilot)
2820103	Adit Fed Fin 48 (pilot)
2820104	Adit St Fin 48 (pilot)
2820105	Adit Fed Pilot Fasb 109
2820106	Adit St Pilot Fasb 109

2820107	Adit State Nc Rate Change
2820108	Adit Fed Nc Rate Change
2820110	Adit Fed Elec Lake Murray Dam
2820111	Adit St Dam Basis Dif
2820112	Adit Fed Dam Basis Dif
2820113	Adit Federal West Texas
2820114	Adit St Gas Mfg Unrecovered Pl
2820115	Adit Fed Gas Mfg Unrecovered P
2820142	Adit St Dam Research
2820143	Adit Fed Dam Research Project
2820144	Adit Fed Elec Research Project
2820145	Adit St Elec Research Project
2820146	Adit Fed Elec Res And Exp
2820147	Adit Fed Gas Res And Exp
2820148	Adit State Elec Res And Exp
2820149	Adit St Gas Res And Exp
2820150	Adit Fed Basis Old Nuc Amended
2820151	Adit St Basis Old Nuc Amended
2820200	Acc Def Fed Inc Tax-other Prop
2820300	Acc Def St Inc Tax-other Prop
2820400	Research And Exp Adit Fed
2820500	Research And Exp. Adit St
2830000	Accum Deferred Income Tax
2830001	Adit Fed Wesths Litigation
2830002	Adit St Wesths Litigation
2830003	Adit Fed Roto Shot Peen
2830004	Adit St Roto Shot Peen
2830005	Adit Fed Elec Erip
2830006	Adit Fed Gas Erip
2830007	Adit Fed Transit Erip
2830008	Adit Fed Nonoper Erip
2830009	Adit St Elec Erip
2830010	Adit St Gas Erip
2830011	Adit St Transit Erip
2830012	Adit St Nonoper Erip
2830013	Adit Fed Elec Prop Taxes
2830014	Adit Fed Gas Prop Taxes
2830015	Adit St Elec Prop Taxes
2830016	Adit St Gas Prop Taxes
2830017	Adit Fed Elec Fuel
2830018	Adit Fed Gas Fuel
2830019	Adit St Elec Fuel
2830020	Adit St Gas Fuel
2830021	Adit Fed Elec Res And Exp
2830022	Adit Fed Gas Res And Exp

2830023	Adit Fed Tran Res And Exp
2830024	Adit St Elec Res And Exp
2830025	Adit St Gas Res And Exp
2830026	Adit St Tran Res And Exp
2830027	Adit Fed Nuc Decom & Decontam
2830028	Adit St Nuc Decom And Decontam
2830029	Adit Fed Elec Dem Side Mgt
2830030	Adit St Elec Dem Side Mgt
2830031	Adit Fed Elec Ls Reacq Debt
2830032	Adit Fed Gas Ls Reacq Debt
2830033	Adit St Elec Ls Reacq Debt
2830034	Adit St Gas Ls Reacq Debt
2830035	Adit Fed Gas Ht Water Heaters
2830036	Adit St Gas Ht Water Heaters
2830037	Adit Fed Elec Storm Damage
2830038	Adit St Elec Storm Damage
2830039	Adit Fed Elec Pension Exp
2830040	Adit Fed Gas Pension Exp
2830041	Adit Fed Tran Pension Exp
2830042	Adit Fed Nonop Pension Exp
2830043	Adit St Elec Pension Exp
2830044	Adit St Gas Pension Exp
2830045	Adit St Tran Pension Exp
2830046	Adit St Nonop Pension Exp
2830047	Adit Fed Elec Ltd
2830048	Adit Fed Gas Ltd
2830049	Adit Fed Transit Ltd
2830050	Adit Fed - St Bonus
2830051	Adit St Gas Ltd
2830052	Adit St Transit Ltd
2830053	Adit Fed Non Oper Knd Exchng
2830054	Adit St Non Oper Kind Exchngs
2830055	Adit State Pal Cen Transit
2830056	Adit State Pal Ctr Elec
2830057	Adit State Pal Ctr Gas
2830058	Adit State Pal Ctr Non Oper
2830059	Adit Fed Pal Ctr Elec
2830060	Adit Fed Pal Ctr Gas
2830061	Adit Fed Pal Ctr Transit
2830062	Adit Fed Pal Ctr Non Oper
2830063	Adit State Nonop Exec Trust
2830064	Adit Fed Nonop Exec Trust
2830065	Adit Fed Non Oper-invol Conv
2830066	Adit St Non Oper-invol Conv

2830067	Adit-federal-psnc-195 Merger C
2830068	Adit-state-psnc-195 Merger Cos
2830069	Adit-fed-psnc-secondary Mkt
2830070	Adit-st-psnc-secondary Mkt
2830071	Adit Federal Psnc - Prepayment
2830072	Adit State Psnc - Prepayment
2830073	Adit-federal-psnc-enviromental
2830074	Adit-state-psnc-enviromental C
2830075	Adit-federal-psnc-exc Def Taxe
2830076	Adit-state-psnc-exc Def Taxes
2830077	Adit-federal-psnc-cardinal
2830078	Adit-state-psnc-cardinal
2830079	Adit-federal-psnc-y2k
2830080	Adit State - Prepay
2830081	Adit Psnc Reg Credit Fed Taxes
2830082	Adit Fed Elec Gridsouth
2830083	Adit State Elec Gridsouth
2830084	Adit Fed Elec Prepayments
2830085	Adit Fed Gas Prepayments
2830086	Adit State Elec Prepayments
2830087	Adit State Gas Prepayments
2830088	Accum Def Fed Inc Taxes - Spr
2830089	Adit-fed Def Pipeline Integ
2830090	Adit-st Def Pipeline Integ
2830091	Adit-fed Vacation Carryover
2830092	Adit-st Vacation Carryover
2830093	Adit Fed Elec Research Payment
2830094	Adit St Elec Research Payment
2830095	Adit-fed Bond Prepmt Penalty
2830096	Adit-st Bond Prepmt Penalty
2830097	Adit-fed Conservation Program
2830098	Adit-st Conservation Program
2830099	Adit Fed Defer Capacity
2830100	Adit Federal Prepayments
2830101	Adit State Prepayments
2830102	Adit-fed Workers Comp Ibnr
2830103	Adit-state Workers Comp Ibnr
2830104	Adit Fed Btl Interest On Eiz
2830105	Adit St Btl Interest On Eiz
2830106	Adit - 2007 Swap - State
2830107	Adit - 2007 Swap - Federal

2830108	Def Inc Tax-fed-over Under Gm
2830109	Def Inc Taxes-st-over Undergm
2830110	Adit Fed Elec Nustart
2830111	Adit St Elec Nustart
2830112	Def Inc Tax - Fed Nol
2830113	Def Inc Tax Liab-fed-financial
2830114	Def Inc Tax Liab-fed-oci
2830115	Def Inc Tax - Fed Nol
2830116	Def Inc Tax Liab-sta-financial
2830117	Def Inc Tax Liab-state-oci
2830118	Adit Fed Rec Cap Reg Asset
2830119	Adit St Rec Cap Reg Asset
2830120	Adit - 2008 20m Swap-state
2830121	Adit - 2008 20m Swap-federal
2830122	Adit Fed Of St Nol And Credits
2830123	Adit Fed Canadys Refined Prtsh
2830124	Adit St Canadys Refined Prtshp
2830125	Adit Fed Cope Refined Prtshp
2830126	Adit St Cope Refined Prtshp
2830127	Adit Fed Rate Case Costs
2830128	Adit St Rate Case Costs
2830129	Adit St Defer Capacity
2830130	Adit Fed Fukishima Reg Asset
2830131	Adit St Fukishima Reg Asset
2830132	Adit St Gas Wna Cap Reg Asset
2830133	Adit Fed Gas Wna Cap Reg Asset
2830134	Adit St Wholesale Fuel Under-c
2830135	Adit Fed Wholesale Fuel Under-
2830136	Adit St Unrecovered Plant- Can
2830137	Adit Fed Unrecovered Plant- Ca
2830138	Adit-fed Brandon Shores Llc
2830139	Adit St Brandon Shores Llc
2830140	Adit Fed Louisa Refined Llc
2830141	Adit St Louisa Refined Llc
2830142	Adit Fed Grants
2830143	Adit St Grants
2830144	Adit Fed Urquhart Unit 3
2830145	Adit Fed Mcmeekin
2830146	Adit Fed Srfi Llc
2830147	Adit St Urquhart Unit 3
2830148	Adit St Mcmeekin
2830149	Adit St Srfi Llc
2830150	Adit-federal-contribution Limi
2830151	Adit- Fed Reg Asset-fuel Track
2830152	Adit- St Reg Asset-fuel Tracke
2830153	Adit Fed Btl Fin 48 Int/exp

2830154	Adit St Btl Fin 48 Int Inc/exp
2830155	Adit-fed-concepts To Companies
2830156	Adit State-concepts To Compani
2830157	Adit Fed Elec Pilot Fin48 Int
2830158	Adit St Elec Pilot Fin48 Int E
2830160	Adit-federal-def Gain-laterals
2830161	Adit Fed Elec Nnd Fas 109
2830162	Adit St Elec Nnd Fas 109
2830163	Adit Fed Nnd Reg Asset Basis D
2830164	Adit St Nnd Reg Asset Basis Di
2830166	Adit Fed Pilot Fasb 109
2830167	Adit St Pilot Fasb 109
2830168	Adit Fed Pilot Interest/prof F
2830169	Adit St Pilot Interest/prof Fe
2830170	Adit-federal-def Gain-lng Sale
2830171	Adit St Reg Cust Aw Prg Vint
2830172	Adit Fed Reg Cust Aw Prg Vint
2830173	Adit St Vcs Cost Under Rateor
2830174	Adit Fed Vcs Cost Under Rateor
2830175	Adit Fed Aro Elec Reg Asset
2830176	Adit St Aro Elec Reg Asset
2830177	Adit Fed Aro Gas Reg Asset
2830178	Adit St Aro Gas Reg Asset
2830179	Adit Fed Nnd Carrying Cost-reg
2830180	Adit-federal-short Term Bonus
2830182	Adit Fed Apog Llc
2830183	Adit St Apog Llc
2830184	Adit St Nnd Carrying Cost-reg
2830185	Adit Fed Fin 48
2830186	Adit St Fin 48
2830187	Adit Fed Elec Jad Contract Ter
2830188	Adit St Elec Jad Contract Term
2830189	Adit Fed Elec Cybersecurity
2830190	Adit-state-short Term Bonus
2830191	St Elec Serp Reg Rec
2830192	St Gas Serp Reg Rec
2830193	Fed Elec Serp Reg Rec
2830194	Fed Gas Serp Reg Rec
2830195	Fed Elec Of St Nol And Credit
2830196	St Elec Serp Fas 158
2830197	St Gas Serp Fas 158
2830198	Fed Elec Serp Fas 158
2830199	Fed Gas Serp Fas 158
2830200	Adit Fed - Pension
2830201	St Elec Pension Reg Rec

2830202	St Gas Pension Reg Rec
2830204	St Elec Pension Fas 158
2830205	St Gas Pension Fas 158
2830206	Fed Elec Pension Reg Rec
2830207	Fed Gas Pension Reg Rec
2830208	Fed Elec Pension Fas 158
2830209	Fed Gas Pension Fas 158
2830210	Adit Fed Elec Net Metering
2830211	Adit St Elec Net Metering
2830212	Adit St Gas Pipeline Integrity
2830213	Adit Fed Gas Pipeline Integrit
2830214	Adit St Elec Cybersecurity
2830216	Adit Fed Wo 17 Carrying Costs
2830217	Adit St Wo 17 Carrying Costs
2830218	Adit Fed Fin 48 - Abandonment
2830219	Adit St Fin 48 - Abandonment
2830300	Adit State - Pension
2830301	St Elec Opeb Reg Rec
2830302	St Gas Opeb Reg Rec
2830306	Fed Elec Opeb Reg Rec
2830307	Fed Gas Opeb Reg Rec
2830308	Adit Fed Dimp(dist Int Mgmt)
2830309	Adit St Dimp(dist Int Mgmt)
2830310	Adit Fed Brunner Island Llc
2830311	Adit St Brunner Island Llc
2830312	Adit Fed Hedging
2830313	Adit St Hedging
3500120	Superint Operations
3500121	Superint Oper Chartered
3500125	Superint Oper Special Bus
3500220	Superint Supp And Exp Oper
3500221	Super Supp & Exp Oper Chartrd
3500225	Super Supp & Exp Oper Spec Bus
3500320	Garage Empl Operations
3500321	Garage Empl Oper Chartered
3500325	Garage Empl Oper Special Bus
3500420	Garage Supp And Exp Operations
3500421	Garage Supp & Exp Oper Chartrd
3500425	Garge Supp & Exp Oper Spec Bus
3500720	Pass Driver And Conduct Oper
3500721	Pass Drvr & Cond Oper Chartrd
3500725	Pass Drvr & Cond Oper Spec Bus

3500820	Fuel For Passenger Bus
3500821	Fuel Chartered
3500825	Fuel Special Bus
3500920	Lubric Passenger Bus Oper
3500921	Lubricants Oper Chartered
3500925	Lubricants Oper Special Bus
3501520	Oth Transp Employees
3501521	Oth Transp Emp Chartered
3501525	Oth Transp Emp Special Bus
3501620	Oth Transp Supplies And Exp
3501621	Oth Transp Supp & Exp Chartrd
3501623	Oth Transp Supp & Exp Dart Opr
3501625	Oth Transp Supp & Exp Spec Bus
3501720	Rent Of Roll Stk Leased Buses
3501721	Rent Of Roll Stk Chartered
3501725	Rent Of Roll Stk Special Bus
3509990	Conduct Trans Oper Bl Transfer
3510120	Superintendence Maint
3510121	Superintend Maint Chartered
3510125	Superintend Maint Special Bus
3510220	Superint Maint Supp And Exp
3510221	Supernt Mnt Supp & Exp Chartrd
3510225	Suprnt Mnt Supp & Exp Spec Bus
3510420	Shop Supplies And Expenses
3510421	Shop Supplies & Exp Chartered
3510425	Shop Supplies & Exp Spec Bus
3510520	Shop Structures Maint
3510521	Shop Structures Maint Chartrd
3510525	Shop Structures Maint Spec Bus
3510620	Shop Equipment Maint
3510621	Shop Equipment Maint Chartered
3510625	Shop Equipment Maint Spec Bus
3511420	Station & Misc Structrs Maint
3511421	Station & Misc Struct Chartrd
3511425	Station & Misc Struct Spec Bus
3511620	Transit Bodies Maint
3511621	Tran Bodies Maint Chartered
3511625	Tran Bodies Maint Special Bus
3511720	Tran Chassis Maint
3511721	Tran Chassis Maint Chartered
3511723	Tran Chassis Maint Dart

3511725	Tran Chassis Maint Special Bus
3512220	Rental Of Tires And Tubes
3512221	Rent Of Tires & Tubes Chartrd
3512225	Rent Of Tires & Tubes Spec Bus
3512320	New Flyer Maint Warr Credits
3519990	Conduct Trans Maint Bl Transfr
3600320	Advertising
3600321	Advertising Chartered
3600325	Advertising Special Bus
3609990	Advertising Traffic Bl Transfr
3700120	Admin And General Salaries
3700122	Admin & Gen Salaries Chartered
3700124	Admin & Gen Sal Bonus Incentv
3700125	Admin And Gen Sal Special Bus
3700128	Admin And Gen Sal Section 9
3700220	Office Supp And Exp
3700221	Off Supp And Exp Chartered
3700223	Off Supp & Exp All Aboard Prog
3700228	Off Supp And Exp Section 9
3700420	Outside Serv Employed
3700421	Out Serv Employ Chartered
3700422	Out Serv Holding Co Oh
3700520	Rents
3700521	Rents Chartered
3701020	Pension
3701021	Benefits
3701320	Reg Comm Expenses
3701520	Injuries And Damages
3701521	Injuries And Damages Chartered
3701620	Insurance
3701621	Insurance Chartered
3701625	Insurance Special Bus
3701820	Misc General Expenses
3701821	Misc Gen Exp Chartered
3701822	Misc Gen Exp Trans Insurance
3701823	Misc Gen Exp Trans Warranty
3701824	Misc Gen Exp Trans Rework
3701920	General Advert Expenses
3701921	Gen Advert Exp Chartered
3701925	Gen Advert Exp Special Bus
3703020	Misc Gen Exp Com Plt Reimbrsmt
3709990	A And G Oper Bl Transfer
3710220	Misc General Plant
3710221	Misc Gen Plant Chartered

3710320	Misc Gen Plant Environmental
3719990	A And G Maint Bl Transfer
4030000	Depreciation Expense
4030001	Depreciation Exp-scana Alloc
4030020	Depr Exp-purch Utility Plant
4035000	Depr Expense - Synfuel Credits
4040000	Amortization Expense
4040001	Amort Exp Srsp
4040002	Amort Exp Chas Franchise
4040003	Westvaco Gen Amort Expense
4040004	Amortization Exp. For Cis
4040005	Amort Exp Cola Franchise
4040006	Amort-metro Plex Leasehold
4040007	Amort - N Chas Flex
4040402	Amortization-ferc Acct 402
4040500	Amort Of Gas Billing System
4043002	Amortization Expense
4043003	Amort Exp Of Organization Cost
4050000	Amort Def Startup Costs
4060000	Amort Of Elec Plnt Acq Adj
4060001	Amt Of Gas Plant Acquistn Adj
4060002	Amort Plt Acq Adj-hagood Turb
4070000	Amort Of Prop Loss
4070001	Amort Of Unrec Plant Parr
4070002	Amort Of Unrec Plant Hagood
4070003	Amort Demol Parr Plant
4070004	Amort Demol Hagood Plant
4070005	Amortization Of Chas-franchise
4070006	Amortization Of Cola-franchise
4070007	Amort Reg Asset - Purh Power
4070008	Amort Prop Air Facil Cola
4070009	Amort Prop Air Facil Chas
4070010	Amort Can1 Unrecovered Plant
4070011	Amort Can2-3 Unrecovered Plant
4073002	It Rev Nonassoc Co Z 2-1 Jmpr
4073007	Penalty Revenue Non Assoc Co
4073010	Amort Wateree Scrubber Def
4073020	Amort Der Avoided Costs Deferr
4073021	Amort Der Incremental O&m Cost
4073022	Amort Der Incremental Capital
4073062	It Rev Nonassoc Pal 1st Day Rt
4073072	It Rev Nonassoc Pal Sub Day Rt

4073082	It Rev Nonassc Z1and2 Over Mdt
4073092	It Rev Nonassc Z1and2 It Usage
4073102	It Rev Asso Sce&g Z2-1 Firmjmp
4073107	Penalty Revenue Assoc Co Sceg
4073162	It Rev Asso Sceg Pal 1st Day
4073172	It Rev Asso Sceg Pal Sub Day
4073182	It Rev Asso Sceg Z1 2 Overmdtq
4073192	It Rev Asso Sce&g Z1&2 It Usag
4073202	It Rev Asso Semi Z2-1 Firmjmpr
4073207	Penalty Revenue Assoc Co Semi
4073254	It Rev Assoc Semi St Res Share
4073262	It Rev Asso Semi Pal 1st Day
4073272	It Rev Asso Semi Pal Sub Day
4073282	It Rev Asso Semi Z1 2 Overmdtq
4073292	It Rev Asso Semi Z1 2 It Usage
4073482	It Rev Nonassoc Alt Del Pt Z1
4073554	It Rev Nonasso St Reserv Share
4073562	It Rev Nonass St Pal1st Day Rt
4073572	It Rev Nonass St Palsub Day Rt
4073582	It Rev Nonass St Z1 2 Overmdtq
4073592	It Rev Nonass St Z1 2 It Usage
4074000	It Revenue Credit - Contra
4081000	Tx Oth Than Inc Tx Util
4081001	Tx Oth Than Inc Tx Pyrl-atl
4081990	Tx Oth Than Inc Tx Transfer
4082000	Tx Oth Than Inc Tx Oth Inc-ded
4082001	Tx Oth Than Inc Tx Bl Trnfr
4082008	Sci License Expense
4091001	Inc Tx Fed Elec Util
4091002	Inc Tx Fed Nuc Util
4091003	Inc Tx Fed Gas Util
4091004	Inc Tx Fed Tran Util
4091005	Inc Tx St Elec Util
4091006	Inc Tx St Nuc Util
4091007	Inc Tx St Gas Util
4091008	Inc Tx St Tran Util
4091009	Federal Estimated Income Tax
4091010	State Estimated Income Tax
4091011	Inc Tax Fed - Schi
4092000	Inc Tx Fed Oth Inc And Ded
4092001	Inc Tx St Oth Inc And Ded
4092009	Fed Estimated Inc Tax - Btl
4092010	State Estimated Inc Tax - Btl
4092011	Inc Tax Fed - Schi

4101000	Def Inc Tax Fed
4101001	Def Inc Tax State
4101002	Def Fed Tx Accel Amort
4101003	Def St Tx Accel Amort
4101004	Def Fed Tx Elec Depr
4101005	Def Fed Tx Gas Depr
4101006	Def Fed Tx Tran Depr
4101007	Def St Tx Elec Depr
4101008	Def St Tx Gas Depr
4101009	Def St Tx Tran Depr
4101010	Def Fed Tx West Litig
4101011	Def St Tx West Litig
4101012	Def Fed Tx West Cr
4101013	Def St Tx West Cr
4101014	Def Fed Tx Nuc Refuel
4101015	Def St Tx Nuc Refuel
4101016	Def Fed Tx Roto Shot
4101017	Def St Tx Roto Shot
4101018	Def Fed Tx Elec Prop Tx
4101019	Def Fed Tx Gas Prop Tx
4101020	Def St Tx Elec Prop Tx
4101021	Def St Tx Gas Prop Tx
4101022	Def St Tx Elec Prop Tx 10yr
4101023	Def St Tx Gas Prop Tx 10yr
4101024	Def Fed Tx Elec Unbill Rev
4101025	Def Fed Tx Gas Unbill Rev
4101026	Def St Tx Elec Unbill Rev
4101027	Def St Tx Gas Unbill Rev
4101028	Def Tx Elec Uoi
4101029	Def Tx Gas Uoi
4101030	Def Tx Tran Uoi
4101031	Def Fed Tx Elec Gain Debt
4101032	Def St Tx Elec Gain Debt
4101033	Def Fed Tx Nuc Interest
4101034	Def St Tx Nuc Interest
4101035	Def Fed Tx Inc Nu Fu Am
4101036	Def St Tx Inc Nu Fu Am
4101037	Def Fed Tx Elec Research
4101038	Def Fed Tx Gas Research
4101039	Def Fed Tx Tran Research
4101040	Def St Tx Elec Research
4101041	Def St Tx Gas Research
4101042	Def St Tx Tran Research
4101043	Def Fed Tx Elec Intangibles
4101044	Def Fed Tx Gas Intangibles
4101045	Def Fed Tx Tran Intangibles
4101046	Def St Tx Elec Intangibles

4101047	Def St Tx Gas Intangibles
4101048	Def St Tx Tran Intangibles
4101049	Def Fed Tx Elec Basis Dif
4101050	Def Fed Tx Gas Basis Dif
4101051	Def St Tx Elec Basis Dif
4101052	Def St Tx Gas Basis Dif
4101053	Def Fed Tx Elec Storm
4101054	Def St Tx Elec Storm
4101055	Def Fed Tx Elec Conserv
4101056	Def St Tx Elec Conserv
4101057	Def Fed Tx Elec Pension
4101058	Def Fed Tx Gas Pension
4101059	Def Fed Tx Tran Pension
4101060	Def St Tx Elec Pension
4101061	Def St Tx Gas Pension
4101062	Def St Tx Tran Pension
4101063	Def Fed Tx Elec Pal Ctr
4101064	Def Fed Tx Gas Pal Ctr
4101065	Def Fed Tx Tran Pal Ctr
4101066	Def St Tx Elec Pal Ctr
4101067	Def St Tx Gas Pal Ctr
4101068	Def St Tx Tran Pal Ctr
4101069	Def Fed Tx Elec Kerp
4101070	Def Fed Tx Gas Kerp
4101071	Def Fed Tx Transit Kerp
4101072	Def St Tx Elec Kerp
4101073	Def St Tx Gas Kerp
4101074	Def St Tx Tran Kerp
4101075	Def Fed Tx Elec Erip
4101076	Def Fed Tx Gas Erip
4101077	Def Fed Tx Tran Erip
4101078	Def St Tx Elec Erip
4101079	Def St Tx Gas Erip
4101080	Def St Tx Tran Erip
4101081	Def Fed Tx Elec Fuel
4101082	Def Fed Tx Gas Fuel
4101083	Def St Tx Elec Fuel
4101084	Def St Tx Gas Fuel
4101085	Def Fed Tx Fin 48
4101086	Def St Tx Fin 48
4101090	Prov Def Fed Inc Tax - Calpine
4101091	Prov Def State Inc Tax - Calpi
4101101	Def Tax St Wateree Synfuel
4101102	Def Tax St Canadys Synfuel
4101104	Def Tax Fed Wateree Synfuel
4101105	Def Tax Fed Canadys Synfuel
4101201	Def Fed Tax Elec Dam Depr

4101202	Def Fed Tax Elec Dam Research
4101203	Def Fed Tax Elec Dam Basis
4101204	Def St Tax Elec Dam Depr
4101205	Def St Tax Elec Dam Research
4101206	Def St Tax Elec Dam Basis
4102000	Def Fed Tx Oth Inc And Ded
4102001	Def St Tx Oth Inc And Ded
4102002	Def Fed Tx Nonoper Kerp
4102003	Def St Tx Nonoper Kerp
4102004	Def Fed Tx Nonoper Erip
4102005	Def St Tx Nonoper Erip
4102006	Def Fed Tx Nonoper Pal Ctr
4102007	Def St Tx Nonoper Pal Ctr
4102008	Def Fed Tx Nonoper Pension
4102009	Def St Tx Nonoper Pension
4102010	Def St Inctx Cltch-wat
4102011	Def Fd Inctx Cltch-wat
4102012	Def St Inctx Cltch-cdy
4102013	Def Fd Inctx Cltch-cdy
4111000	Def Tx Cr Elec Uoi
4111001	Def Tx Cr Gas Uoi
4111002	Def Tx Cr Tran Uoi
4111003	Def Fed Tx Cr Elec Gain Debt
4111004	Def St Tx Cr Elec Gain Debt
4111005	Def Fed Tx Cr Int Nu
4111006	Def St Tx Cr Int Nu
4111007	Def Fed Tx Cr Nu Fuel Am
4111008	Def St Tx Cr Nu Fuel Am
4111009	Def Fed Tx Cr Elec Loss Debt
4111010	Def Fed Tx Cr Gas Loss Debt
4111011	Def St Tx Cr Elec Loss Debt
4111012	Def St Tx Cr Gas Loss Debt
4111013	Def Fed Tx Cr Elec Basis Dif
4111014	Def Fed Tx Cr Nuc Basis Dif
4111015	Def Fed Tx Cr Gas Basis Dif
4111016	Def Fed Tx Cr Tran Basis Dif
4111017	Def St Tx Cr Elec Basis Dif
4111018	Def St Tx Cr Nuc Basis Dif
4111019	Def St Tx Cr Gas Basis Dif
4111020	Def St Tx Cr Tran Basis Dif
4111021	Def Fed Tx Cr Elec Lit Rev
4111022	Def St Tx Cr Elec Lit Rev
4111023	Def Fed Tx Cr Accel Amort
4111024	Def St Tx Cr Accel Amort
4111025	Def Fed Tx Cr Elec Depr
4111026	Def Fed Tx Cr Nuc Depr
4111027	Def Fed Tx Cr Gas Depr

4111028	Def Fed Tx Cr Tran Depr
4111029	Def St Tx Cr Elec Depr
4111030	Def St Tx Cr Nuc Depr
4111031	Def St Tx Cr Gas Depr
4111032	Def St Tx Cr Tran Depr
4111033	Def St Tx Cr Elec Int 7yr
4111034	Def St Tx Cr Gas Int 7yr
4111035	Def Fed Tx Cr West Litig
4111036	Def St Tx Cr West Litig
4111037	Def Fed Tx Cr Elec Prop Tax
4111038	Def Fed Tx Cr Gas Prop Tax
4111039	Def St Tx Cr Elec Prop Tax
4111040	Def St Tx Cr Gas Prop Tax
4111041	Def Fed Tx Cr Elec Unbill Rev
4111042	Def Fed Tx Cr Gas Unbill Rev
4111043	Def St Tx Cr Elec Unbill Rev
4111044	Def St Tx Cr Gas Unbill Rev
4111045	Def Fed Tx Cr Elec Storm
4111046	Def St Tx Cr Elec Storm
4111047	Def Fed Tx Cr Amort West Cr
4111048	Def St Tx Cr Amort West Cr
4111049	Def Fed Tx Cr Elec Ciac
4111050	Def Fed Tx Cr Gas Ciac
4111051	Def St Tx Cr Elec Ciac
4111052	Def St Tx Cr Gas Ciac
4111053	Def Fed Tx Cr Elec Pal Ctr
4111054	Def Fed Tx Cr Gas Pal Ctr
4111055	Def Fed Tax Cr Tran Pal Ctr
4111056	Def St Tax Cr Elec Pal Ctr
4111057	Def St Tx Cr Gas Pal Ctr Lease
4111058	Def St Tx Cr Tran Pal Ctr Leas
4111059	Def Fed Tx Cr Elec Kerp
4111060	Def Fed Tx Cr Gas Kerp
4111061	Def Fed Tx Cr Tran Kerp
4111062	Def St Tx Cr Elec Kerp
4111063	Def St Tx Cr Gas Kerp
4111064	Def St Tx Cr Tran Kerp
4111065	Def Fed Tx Cr Elec Erip
4111066	Def Fed Tx Cr Gas Erip
4111067	Def Fed Tx Cr Tran Erip
4111068	Def St Tx Cr Elec Erip
4111069	Def St Tx Cr Gas Erip
4111070	Def St Tx Cr Tran Erip
4111071	Def Fed Tx Cr Elec Ovrhds
4111072	Def Fed Tx Cr Gas Ovrhds
4111073	Def St Tx Cr Elec Ovrhds
4111074	Def St Tx Cr Gas Ovrhds

4111075	Def Fed Tx Cr Decom
4111076	Def St Tx Cr Decom
4111077	Def Fed Tx Cr Elec Fuel
4111078	Def Fed Tx Cr Gas Fuel
4111079	Def St Tx Cr Elec Fuel
4111080	Def St Tx Cr Gas Fuel
4111081	Def Fed Tx Cr Nuc Refuel
4111082	Def St Tax Cr Nuc Refuel
4111083	Def Fed Tax Cr Roto Shot
4111084	Def St Tax Cr Roto Shot
4111085	Def Fed Tx Cr Elec Sale Tax
4111086	Def Fed Tx Cr Gas Sale Tax
4111087	Def St Tx Cr Elec Sale Tax
4111088	Def St Tx Cr Gas Sale Tax
4111089	Def Inc Tax Cr Federal
4111090	Def Inc Tax Cr State
4111091	Def Tax Invest Tax Cr Restored
4111092	Def Fed Tax Cr Gas Depr
4111093	Def Fed Tax Cr Gas Depr
4111094	Def Fed Tx Cr Fin 48
4111095	Def St Tx Cr Fin 48
4111101	Def Tax Cr St Wateree Synfuel
4111102	Def Tax Cr St Canadys Synfuel
4111104	Def Tax Cr Fed Wateree Synfuel
4111105	Def Tax Cr Fed Canadys Synfuel
4111202	Def Fed Tax Elec Dam Research
4111203	Def Fed Tax Elec Dam Basis
4111205	Def St Tax Elec Dam Research
4111206	Def St Tax Elec Dam Basis
4112000	Def Fed Tx Cr
4112001	Def St Tx Cr
4112002	Def Fed Tx Cr Otarre
4112003	Def St Tx Cr Otarre
4112004	Def Fed Tx Cr Kerp
4112005	Def St Tax Cr Kerp
4112006	Def Fed Tax Cr Erip
4112007	Def St Tax Cr Erip
4112008	Def Fed Tx Decom
4112009	Def St Tx Decom
4112010	Def Fed Tx Cr Non Oper Inc
4112011	Def St Tx Cr Non Oper Inc
4112101	Def Tax Cr St-wateree Synfuel
4112102	Def Tax Cr St -canadys Synfuel
4112104	Def Tax Cr Fed Wateree Synfuel
4112105	Def Tax Cr Fed Canadys Synfuel

4114000	Tax Credit Adj Elec
4114001	Tax Credit Adj Nuc
4114002	Tax Credit Adj Gas
4114003	Tax Credit Adj Tran
4114004	Tax Credit Adj Net Elec
4114005	Tax Credit Adj Net Gas
4114006	Tax Credit Adj Net Tran
4114007	Tax Credit Adj Restored
4114100	Def Tax Cr Fed Wateree Synfuel
4114101	Def Tax Cr Fed Canadys Synfuel
4114104	Def Tax Cr Can Fed Gas
4114105	Def Tax Cr Wat Fed Gas
4115001	Def Fed Syn Tax Cr-wat
4115002	Def Fed Syn Tax Cr-cdy
4115003	Investment Tax Cr-other Income
4115101	Def Fed Syn Tax Cr Chgd Watere
4115102	Def Fed Syn Tax Cr Chgd Canady
4118000	Gains From Disp Of Allow
4119000	Losses From Disp Of Allow
4140000	Depr Exp Gas
4140001	Acc Amort Misc Gas
4140002	Amort Expense Gas Gis
4140003	Common Amort Alloc To Gas
4140004	Amrt Exp Gas Franchise Fees
4140005	Amort Gas Plt Acquisition Adj
4140006	Amort-metro Plex Bldg Leasehol
4140007	Amort - N Chas Flex
4140008	Amort-n Charleston Gas Ops Ctr
4140500	Amort For Scana Software
4140550	Depr For Scana Assets
4140800	Amort For Sega Assets
4140850	Depr For Sega Assets
4144320	Depr Exp Tran
4144620	Amort Of Tran Plnt Sftwr
4150000	Rev From Merch
4150005	Gross Sales Cng Phill Stations
4150050	Sceg Appliance Repair Plans
4150051	Sceg Hvac Repair Plans
4150052	Sceg Wtr Heater Sales Program
4150053	Sceg Wtr Heater Financing Prg
4150054	Sceg Hvac Dealer Financing Pr

4150055	Sceg Wtr Line Replacemt Plan
4150056	Sceg Gas Wtr Htr Repair Replc
4150057	Sceg Sewer Line Repair Plans
4150058	Sceg In-home Gas Pipe Prot Pl
4150059	Sceg In-home Elct Line Rep Pl
4150060	Internal Wh Sales/finance Rev
4150061	Preferred Sewer Line Rev
4150062	In Home Plumbing Rep Rev
4150063	Home Surge Prot $1k/yr
4150064	Gas Log Repair Plan Rev
4150065	Home Surge Prot $2k/yr
4150066	Home Surge Prot Rev$3k/yr
4150067	Sceg Hvac Repr Plns(1-4 Units)
4150111	Gross Sales Appliances
4150112	Cng Appliancesales Distributor
4150113	Subordinations Hvac Revenue
4150114	Service Contract Revenues
4150115	Returned Sales Appliances
4150116	Servicecare Cash Call Appl Rev
4150117	Servicecare Appl Contract Rev
4150118	Appliance Service Call Rev
4150119	Servicecare Hvac Contract Rev
4150120	Hvac Service Call Rev
4150121	Servicecare Pipeline Prot Rev
4150122	Servicecare Complete Revenue
4150123	Servicecare Pipe Pro Cash Call
4150124	Servicecare Pipe Prot Servcall
4150125	Servicecare Hvac Cash Call Rev
4150126	Servicecare Water Sewer Rev
4150127	Sc Water Heater-gas Rev
4150128	Sc Wh-electric Lp Rev
4150140	Sc Gas Log Repair Rev
4150141	Sc Gas Log Service Call Rev
4150185	Furnace Repair Plan Revenue
4150190	Sc In Home Plumbing Plan Rev
4150200	Palmetto Franchise Revenue
4150212	Gross Sales Jobbing
4150213	Late Payment Chrg Jobbing
4160000	Exp From Merch
4160005	Cost Of Cng Phill Station Sold
4160050	Sceg Appliance Repair Expenses
4160051	Sceg Hvac Repair Expense
4160052	Sceg Wtr Heater Sales Prgm Ex
4160053	Sceg Wtr Htr Financing Prg Ex
4160054	Sceg Hvac Dealer Financing Ex
4160055	Sceg Wtr Line Replacemt Expns

4160056	Sceg Wtr Htr Repair Replc Exp
4160057	Sceg Sewer Line Repair Exp
4160058	Sceg In-home Gas Pipe Prot Ex
4160059	Sceg In-home Elct Line Rep Ex
4160060	Internal Wh Sales/finance Expe
4160061	Sce&g Gas Log Financing Exp
4160062	Sceg Propane Conv Financing Ex
4160120	Employee Expenses
4160121	Cost Of Appliances Sold
4160122	Cost Of Installing Appliances
4160124	Cost Of Service Contract
4160125	Stock Value Of Returns
4160131	Supervision Merchandise
4160133	Comm & Bonus Merchandise
4160134	Advertising
4160135	Appliance Parts & Serv Merch
4160136	Misc Expenses Merchandise
4160137	Sales Bonuses
4160138	Estimated Hourly Payroll
4160140	Acctg And Cashiering-mdse
4160141	Collecting Cr Rep
4160148	Sc Wh-gas Repair Exp
4160150	Servicecare Contract Costs
4160151	Servicecare Marketing Costs
4160152	Servicecare Misc Costs
4160153	Uncollectible Account
4160154	Serviceare Hvac Contract Cost
4160155	Servicecare Hvac Marktg Costs
4160156	Servicecare Prospect Bonuses
4160157	Servicecare Comp Contract Cost
4160158	Sc Wh-gas Replace Exp
4160159	Sc Wh-electric Lp Exp
4160160	Servicecare Applian Commission
4160161	Servicecare Hvac Commissions
4160162	Servicecare Complete Commissio
4160163	Servicecare Pipe Prot Commissn
4160164	Dominion Repair Prog-labor
4160165	Servccare Pipe Prot Mktg Costs
4160166	Servccare Gas Logs Mktg Costs
4160167	Servcr Wh Repr Repl Mktg Costs
4160168	Servcr Gas Logs Comm Exp

4160170	Servccare Pipe Prot Exp
4160171	Repair Prog Sales Suppt Cost
4160172	Repair Prog Call Center Costs
4160175	Uncollectible Accts Third Part
4160179	Uncollectible Accts Merch
4160180	Sc Gas Log Repair Exp
4160201	Palmetto Franchise Labor Expns
4160202	Palmetto Frchs Contractr-parts
4160203	Palmetto Frchs Contractr-labor
4160204	Palmetto Frchs Misc Expenses
4160223	Cost Of Jobbing
4160231	Supervision Jobbing
4160233	Comm & Bonus Jobbing
4160235	Appliance Parts & Serv Jobbing
4160240	Acctg And Cashiering-jobbing
4160250	Rinnai Referral Fee Expense
4160289	Uncollectible Accts Jobbing
4170000	Nonutility Rev Other
4170001	Nonutil Rev Opr Mnt Fee
4170002	Nonutil Rev Srs H Area Oper
4170003	Nonutil Rev Telecom
4170004	Nonutil Rev Fleet Serv
4170005	Nonutil Rev Ind Coal Sales
4170006	Fed Energy Svc Nonutil Rev
4170007	Btl Rev-nmst Buy\resell Energy
4170008	Non Util Rev-cola Hyd Op Svcs
4170009	Btl Rev - Lt Energy Sales
4170010	Nonutil Rev Cust Contracts
4170011	Nonutil Rev Service Calls
4170012	Nonutil Rev Cash Calls
4170013	Nonutil Rev Franchise
4170014	Btl Rev - Pwr Mkting Swaps
4170015	Nonutil Rev Water Heater Progr
4170016	Nonutil Rev Dominion Wtrhtr Pr
4170024	Deductions Owed The Wacog
4170100	Non Util Rev Cng Retail Sales
4170101	Non Util Rev Gross Sales
4170200	Other Rev-retail Benefits Prog
4170201	Sci-fiber Revenue
4170202	Sci Pmn Revenue Sharing
4170206	Sci Management Fee Revenue
4170207	Sci Pop Access Revenue
4170208	Sci Power Chgs Per Fused Amp
4170210	Sci Tower Revenue

4170211	Sc Rooftop Revenue
4170220	Sci Miscellneous Revenue
4170221	Sci Fiber Revenue Affiliate
4170228	Sci Pwr Chgs Affiliate
4170230	Sci Twr Revenue Affiliate
4170287	Sci Pop Revenue Affiliate
4171000	Exp From Non-utility Opertns
4171001	Exp Frm Nonutil Oper Btl Maint
4171002	Exp Frm Nonutil Oper Btl Depr
4171003	Exp Frm Nonutil Oper Btl Oper
4171004	Exp From Non Util Op-cola Hyd
4171006	Exp-nonut Opr Prov Impair-inv
4171007	Rental Exp To Scpc
4171008	Exp Frm Nonutil Oper Amort Exp
4171009	Exp Frm Nonutil Oper Telecom
4171010	Exp Frm Nonutil Oper Fleet Mbu
4171011	Ind Coal Sale Exp-nonutil Oper
4171012	Pd Serv Mbu Exp Nonutil Oper
4171013	Exp Frm Nonutil Oper-cogs
4171014	Fed Energy Svc Exp Nonutil
4171015	Severance Tax & Other Exp
4171016	Operating Cost Loes
4171017	Deprctn Depletion & Amort Exp
4171018	Exp Frm Nonutl Outsde Srv Call
4171019	Exp Frm Nonutl Oper Cust Refnd
4171020	Exp From Nonutil Oper Other
4171021	Btl Exp-nmst Buy\resell Purch
4171022	Btl Exp-nmst Buy\resell Transm
4171023	Btl Exp-nmst Buy\resell Market
4171024	Exp Frm Nonutil Oper Bad Debt
4171100	Exp Frm Non Util Cog Cng
4171101	Exp Frm Non Util Cost Of Sale
4171114	Btl Exp - Pwr Mkting Swaps
4171201	Sci Salaries
4171202	Sci Employee Benefits
4171205	Sci Sales Commission Expense
4171206	Sci Bonus Expense
4171210	Sci Bad Debt Expense
4171229	Sci Legal Services
4171230	Sci Outside Services Expense
4171232	Sci Depreciation Expense
4171240	Sci Maintenace Expense
4171241	Sci Operatiing Supplies Expens

4171243	Sci Provision/monitor Svc
4171246	Sci Office Supply Expense
4171247	Sci Printing Expense
4171249	Sci Postage/mailing Expense
4171250	Sci Telephone Expense
4171255	Sci Utility Pole Exp
4171260	Sci Transportation Expense
4171261	Sci Lodging Expense
4171262	Sci Subscription/publication
4171263	Sci Membership/dues
4171264	Sci Education/seminars
4171265	Sci Meals & Entertainment
4171268	Sci Advertising Expense
4171269	Sci Temp Services Expense
4171270	Sci Insurance Expense
4171272	Sci Scana Overhead Expense
4171275	Sci Rental Expense
4171278	Sci-misc General Expense
4171280	Sci Admin Allocation
4171285	Sci Rent Expense Affiliates
4171290	Sci Cost Of Sales
4171920	A&g Salaries Non Util Exp
4171921	A&g Off Supp & Exp Non Util
4171923	A&g Outside Serv Non Util Exp
4171930	A&g Misc Gen Exp Non Util
4171931	A&g Rents Non Util Exp
4171935	A&g Maint Gen Plt Non Util Exp
4171936	Billing Costs
4171937	Billing Adjustments
4171938	Nonutility Ist Charges
4180000	Nonopr Rent Inc Sublease Rcpts
4180001	Tower Rental Income Non-assoc
4180002	Non Operating Rental Income
4180009	Rental Inc From Sci
4180010	Ground Rental Income Non-assoc
4181000	Equity In Earn Of Sub Co
4181001	Equity-earnings Of Sub Co Svci
4181002	Equity-earnings Of Sub Co Sps
4181003	Equity-earnings Of Sub Co Semi
4181004	Equity-earnings Of Sub Co Psi
4181005	Equity-earnings Of Sub Co Spr
4181006	Equity-earnings Of Sub Co Sdc
4181007	Equity-earnings Of Sub Co Scpc

4181008	Equity-earnings Of Sub Co Spg
4181009	Equity-earnings Of Sub Co Sci
4181010	Equity-earnings Of Sub Co Scfc
4181011	Equity-earnings Of Sub Co West
4181013	Equity-earnings Of Sub Co Sceg
4181014	Equity-earnings Of Sub Co Genc
4181015	Equity-earnings Of Sub Co Sr
4181028	Equity In Earning Of Sub Co
4181032	Equity Earn Of Sub Co Pscp
4181033	Equity Earn Of Sub Co Blue
4181034	Equity Earn Of Sub Co Prod
4181035	Equity In Earn Of Sub Co - Scg
4181036	Equity Earn Of Sub Co Clean
4181037	Equity Earn Schi
4181060	Equity Earn Sub - Canadys Refi
4181061	Equity Earn Sub - Brandon Shor
4181062	Equity Earn Sub - Louisa Refin
4181063	Equity Earn Sub-brunner Isld R
4190000	Interest And Dividend Income
4190001	Svci Int Inc
4190002	Sps Int Inc
4190003	Semi Int Inc
4190004	Psi Int And Div Inc
4190005	Spr Int And Div Inc
4190006	Sdc Int And Div Inc
4190007	Scpc Int And Div Inc
4190008	Spg Int And Div Inc
4190009	Int And Div Inc Sci
4190010	Int And Div Inc Assoc Co Scfc
4190011	Over Under Fuel Carrying Cost
4190013	Int And Div Inc Assoc Co Sceg
4190014	Int & Div Inc Assoc Co Genco
4190015	Int And Div Inc Sce&g
4190016	Interest And Div Inc-boa Swap
4190017	Int And Div Inc-w Fargo Swap
4190018	Int And Div Inc-boa 100m 125m
4190019	Int And Div Inc - Mizuho
4190020	Int And Div Inc-sce&g Trust I
4190021	Int And Div Inc Dir Tr Def
4190022	Int And Div Inc - Edcp-fund
4190025	Int And Div Inc-genco Boa Swap
4190028	Psnc Int And Div Inc
4190029	Service Interest Income
4190030	Sc Sh Lt Note Interest Income
4190035	Scg Int And Div Inc

4190037	Gas Pipeln Inty Carrying Cost
4190050	Unrealized Gains On Finan Trns
4190051	Unrealized G L On Fpas
4190053	Wtr Htr Earn Interest 3rd Part
4190054	Hvac Earn Interest 3rd Party
4190056	Sega Int And Div Income
4190057	Set Int And Div Income
4190060	Internal Wtr Htr Prog Earn Int
4190061	Gas Log Earn Interest 3rd Prty
4190062	Propane Conv Earn Int 3rd Part
4190080	Int Inc Dsm Carrying Costs
4190085	Int Inc Cipv5 Carrying Costs
4190086	Vcs Cyber Carrying Costs
4190087	New Nuclear Gen Carry Costs
4190090	Int Inc - Der O&m Incremental
4190091	Int Inc - Der Cap Increm-debt
4190092	Int Inc-der Cap Increm-equity
4190093	Int Inc - Der O&m
4190094	Int And Div Inc-bank Ny Mellon
4190095	Int And Div Inc-wachovia Swap
4190096	Int And Div Inc Short Term Inv
4190097	Div Inc Psnc
4190098	Int And Div Inc St Invest Tax
4190099	Int And Div Inc Other
4190100	Temp Inv Tax Int And Div Inc
4190101	Temp Inv Fd-st Exmpt Int-div I
4190102	Temp Inv Fed Exmpt Int-div Inc
4190103	Temp Inv St Exmpt Int-div Inc
4190104	Int And Div Inc Tax Exempt
4190105	Int Income- Govt Money Mkt Fun
4190129	Interest Income - Nu Pool
4190150	Semi Customer Late Charges
4190155	Elimination Account With Sce&g
4190160	Int Inc Sc Pipeline Corp-elimi
4190175	Earned Interest Third Party
4190179	Earned Interest Merchandise
4190190	Earned Interest Merchandise
4190200	Prosolutions Int Inc
4190201	Instel Int Inc
4190202	One Step Interest Income
4190203	Int On Adv To Accutrak
4190204	Int On Adv To Online Energy
4190205	Retailco Int Income
4190207	Int On Advances - Cgtc

4190210	Int-div Inc Mobile Home Hookup
4190211	Int-div Inc Elec Mkt Programs
4190212	Gas Marketing Prog Int Inc
4190213	Emergency Repair Int Inc
4190214	Interest Income Cdm Invest
4190215	Chas Garage Project
4190216	Inv Inc Sccoaltech-wat
4190217	Inv Inc Coaltech 1-cdy
4190218	Wat Deferred Ptnrshp Loss Revs
4190219	Cdy Deferred Ptnrshp Loss Revs
4190221	Inv Inc-canadys Refined Coal
4190222	Inv Inc-cope Refined Coal
4190223	Inv Inc - Brandon Shores Coalt
4190224	Inv Inc - Louisa Refined Coal
4190225	Inv Inc - Brunner Island Refin
4190250	Schi Earnings
4190301	Int And Div Inc Airplane
4190302	Int And Div Inc Sr
4190303	Int And Div Inc Rabbi Trust
4190410	Int-div Inc Scfc Fossil & Nu
4191000	Allow Funds Used Constr Eq
4191001	Sal Dam Carrying Costs-equity
4191100	Interest Income - Affiliate
4199000	Temp Inv Tax Int&div Ga Gas
4199001	Tmp Inv Fed&st Exmpt Ga Gas
4199002	Temp Inv Fed Exempt Ga Gas
4199003	Temp Inv St Exempt Ga Gas
4210000	Misc Nonoper Income
4210001	Misc Nonoper Inc Fta Funds
4210002	Msc Nonopr Inc Cmrpc Sctn9 Fnd
4210003	Misc Non Oper Inc Spec Serv
4210004	Sal Dam Carrying Cost
4210005	Pension Income
4210006	Misc Non Oper Income Nnd Carry
4210007	Gain On Cgt Sale
4210008	Gain On Sci Sale
4210009	Btl Pension - Cgtc
4210010	Btl Pension - Sci
4210050	Srfi Llc
4210100	Misc Nonoper Inc Recy Pap Exp
4210101	Misc Nonoper Inc Recy Pap Rev
4210300	Misc Non Oper Inc Other

4210301	Other Income - Secondary Marke
4210305	Oth In Rel Cap Transco
4210306	Oth Inc Released Cap Sonat
4210307	Oth Inc Released Cap Cgtc
4210309	Rental Income From Poe
4210310	Ciac Tax Gross-up
4210315	Sci Frc Llc Revenue
4210316	Sci Frc Llc Expense
4211000	Gain On Disp Of Prop
4211001	Gain On Disp Of Prop Lknd Exch
4211010	Gain On Disposition Of Prop-le
4212000	Loss On Disp Of Prop
4212010	Loss On Disposition Of Prop-le
4219990	Msc Nonop Inc Chatran Intrm Op
4250000	Miscellaneous Amortization
4250001	Misc Amort-acq Hagood Turb
4250200	Misc Amrt Urq Turbine Wholesl
4260309	Rental Expense For Poe
4261000	Donations
4262000	Life Insurance
4262001	Ins Expense - Prem - Dir Endow
4262002	Ins Exp Csv Directors Endowmnt
4262003	Ins Exp-proceeds Dir Endowment
4263000	Penalities
4264000	Exp-civic Polit & Related Act
4265000	Other Deductions
4265001	Other Deductions Scana
4265002	Misc Inc Ded Dir Endow
4265003	Oth Ded Pine Needle
4265004	Oth Ded Cardinal Exten
4265005	Impairment In Investments
4265006	Impairment Of Goodwill
4265007	Misc Deduct- Security Services
4265008	Misc Inc Ded - Edcp
4265009	Psi Charges Post Inactivation
4265010	Oth Deduct Kerp
4265011	Cgt/dominion Transaction
4265012	Sci/spirit Transaction
4265013	Dominion Merger Expenses
4265020	Oth Deduct Erip
4265030	Oth Deduct Ramsey Grove
4265040	Oth Ded Exp Sale Timbr & Pulpw

4265050	Oth Deduct Employee Clubs
4265060	Oth Deduct Nonutil Environ Exp
4265070	Oth Ded Exp Frm Sale-land
4265080	Oth Deduct Decommission Exp
4265081	Sci Oth Accretion/depreciation
4265090	New Nuclear Abandonment
4265309	Rental Expense For Poe
4265605	Employee Clubs Pine Island
4265606	Employee Clubs Sand Dunes
4265607	Employee Clubs Misty Lake
4265609	Recreational Activities
4265610	Service Awards
4270000	Interest On Long Term Debt
4270001	Int Ltd Orangeburg Bond
4270002	Int Ltd Commt Fees Wachovia Nc
4270003	Distrib Trust Pref Securities
4270004	Interest Ltd-gn Ind Rev Bonds
4270010	Interest Exp-berk Co 2003
4270011	Int Exp 5 49% Due 2 01 24
4270012	Int Exp 6 06% Due 2018
4270013	Interest Exp Arb/loc-fossil
4270014	Interest Exp Arb/loc-allowanc
4270015	Interest Exp Arb/loc-nuclear
4270016	Interest Exp Arb/loc-cap Nucl
4270017	Interest Exp Arb Loan
4270018	Interest Exp Loc
4270020	Interest Exp Spare Parts
4270100	Int Ltd Emission Allow Exp
4270101	Int Ltd Emissn Allw Capitlzd
4270200	Int Ltd Other
4270201	Int Ltd Expensed Fuel
4270202	Int Ltd Capitalized Fuel
4270203	Int Ltd Agent And Commit Fees
4270207	Int Ltd Commt Fees Bk Of Amerc
4270208	Int Ltd Com Fees - Bbt
4270210	Interest Exp-loc Fee-gn Irb
4270300	Int Ltd Note Payable Scana
4280000	Amort Of Debt Disc And Exp
4280001	Amort Of Debt Disc-berk Co
4280003	Amort Debt Exp-prud 2 01 24
4280004	Amort Debt Exp-genco 2018
4280005	Amort Debt Exp-gn Ind Rev Bond
4281000	Amort Of Loss On Reacq Debt

4290000	Amort Of Prem On Debt Cr
4291000	Amort Of Gain On Reacq Debt Cr
4300000	Interest On Debt To Assoc Co
4300003	Int Exp On Adv From Semi Inc
4300005	Interest On Advance From Spr
4300006	Int On Debt - Assoc Co - Sdc
4300007	Int Expense Assoc Co - Scpc
4300010	Int On Debt Assoc Co Scfc
4300012	Intrst On Debt-assoc Cos-scana
4300013	Int On Debt Assoc Co Sceg
4300014	Int On Debt Assoc Co Genco
4300015	Int On Debt Assoc Co- Trust 1
4300018	Int Exp Assoc Co Gas
4300020	Int On Debt Assoc Co Ti
4300028	Money Pool Interest Exp-psnc
4300029	Int On Debt Assoc Co - Svc Co
4300030	Interest Expense-services Co N
4300060	Int On Note - Sh
4300061	Sc Sh Lt Note Interest Expense
4300129	Interest On Advances - Sc
4300416	Int Exp Assoc Co Adv Fh
4300417	Int Exp Assoc Co Adv Nu
4301100	Interest Expense - Affiliate
4310000	Other Interest Expense
4310001	Oth Int Exp Int-cust Deposits
4310002	Oth Int Exp Commercial Paper
4310003	Oth Int Exp Notes Payable
4310004	Oth Int Exp 60m Scana Loan
4310005	Oth Int Exp Deferred Comp Dir
4310006	Int Dbt Assoc Co-elec Ror Rfnd
4310007	Oth Int Exp Bank Loans
4310008	Interest Exp On Short-term Dbt
4310009	Oth Int Exp Comm Paper-fossil
4310010	Oth Int Exp Comm Paper-emiss
4310011	Over Under Fuel Carrying Cost
4310012	Oth Int Exp Comm Paper-nuclear
4310013	Oth Int Exp-cap Int- Nucl Fuel
4310014	Other Interest Expense Semi
4310015	Oth Int Exp-loc-pwr Mkt-soco
4310018	Oth Int Exp Associated Co Gas
4320000	Allw Fnds Used Drng Constr Dbt
4320001	Allow Borrowed Funds-scana Al
4390000	Adj To Retained Earnings

4400000	Residential Sales Elec
4400090	Residential Elec Unbilled
4420000	Commercial Sales Elec
4420001	Industrial Sales Elec
4420090	Commercial Elec Unbilled
4420091	Industrial Elec Unbilled
4440000	Pub Street And Hwy Lgt Elec
4440090	St Lights Unbilled
4450000	Oth Sales To Public Auth Elec
4450090	Opas Unbilled
4470000	Sale-resle Utilts & Pblc Auth
4470001	Mun Sale-resle Fulle Rqur Trff
4470002	Sale For Resale-nmst-s-t
4470003	Impct Stdy Rev Tran Sale-resle
4470004	Sale For Resale- Transm-s-t
4470005	Sale For Resale-nmst-l-t
4470006	Sale For Resale- Transm-l-t
4470007	Sale For Resale Nmst Contra
4470008	Other Sale For Resale Rev
4470009	Trans Rev - Pm St Btl Wheeling
4470090	Sale For Resale Unbilled
4470600	Impact Studies Rev - Transmiss
4480000	Interdepartmental Sales
4490000	Sale Rev Fuel Cls Ovr-undrcoll
4490001	Oth Sale Rev Allocated Rev
4490002	Oth Sale Rev Alloc Rev Contra
4491000	Provision For Rate Refunds
4500000	Delinquent Charges Elec
4510000	Misc Service Revenues
4510001	Misc Ser Rev Return Ck Fees
4510002	Misc Ser Rev Mobile Hm Hookup
4510100	Reserved For Nancy Mctyre
4510600	Investigative Charges
4530000	Sales Of Water _ Water Power
4540000	Rent Frm Elec Prop Facil Chrgs
4540001	Rent From Elec Property
4540002	Facilities Charges Sce&g
4540003	Imbalance Penalty Service
4540004	Rent Elec Prop Lady St Semi
4540005	Rent From Land Lease For Tower
4540100	Rent From Elec Prop-cis Interf
4560000	Other Elec Revenue
4560001	Oth Elec Rev Wheeling
4560003	Oth Elc Rev Invst-fld Collect
4560004	Tth Elec Rev Qre Agreements

4560100	Oth Elec Rev Timber Sales
4560200	Oth Elec Rev Recreat Facilits
4560300	Oth Elec Rev Lk Murr Prmt Fees
4560400	Oth Elec Rev Fish And Wildlife
4561000	Rev From Trans Of Elec Of Othr
4561001	Revenue - Orangeburg Transmiss
4561002	Revenue - Winnsboro Transmissi
4570000	Scana Services Direct Rev
4570001	Scana Services Alloc Rev
4570002	Scana Services Cap Inv Rev
4581000	Sc Alloc Non Affiliate Rev
4582000	Sc Direct Non Affiliate Rev
4600120	Transit Revenue
4600121	Tran Rev 10 Ride Disc Fare
4600122	Tran Rev 40 Ride Disc Fare
4600123	Tran Rev Charit Org Disc Fare
4600220	Tran Rev Special Bus
4600320	Tran Rev Chartered
4600420	Tran Rev Advertising
4600520	Tran Rev Other
4600599	Tran Rev Chas Interim Oper Rev
4600820	Tran Rev Lease
4609990	Tran Rev Oper Rev Bl Transfer
4800000	Residential Sales Gas
4800090	Resident Sales Gas Unbilled
4800095	Resident Sales Gas Unbilled-no
4800101	Residential Gas Sales Rate 101
4800102	Residential Gas Sales Rate 102
4800105	Residential Gas Sales Rate 105
4800110	Residential Gas Sales Rate 110
4800115	Unmetered Lighting Svc-res
4800120	Residential Gas Sales Rate 120
4800190	Reserved For Nancy Mctyre
4800200	Residential Gas Sales Contra
4800900	Promotion And Courtesy Credits
4801000	Residential Gas Sale Nonreg
4810000	Commercial Sales Gas
4810013	Assoc Elec Generation-sceg
4810020	Comm Firm Gas Sales Rate 120
4810025	Comm Firm Gas Sales Rate 125
4810026	Comm Firm Gas Sales Rate 126
4810027	Comm Firm Gas Sales Rate 127
4810035	Cng Gas Sales Rate 135

4810040	Med Gen Serv-comm Rate 140
4810045	Comm Firm Gas Sales Rate 145
4810075	Comm Firm Gas Sls Trans Rt 175
4810090	Commercial Sales Gas Unbilled
4810091	Comm Firm Gas Sales Rate 190
4810095	Comm Firm Gas Sales Rate 195
4810100	Commercial Sales Interupt Gas
4810110	Commercial Sales Gas
4810115	Unmetered Lighting Svc-commer
4810120	Industrial Sales Gas
4810150	Comm Int Gas Sales Rate 150
4810160	Comm Int Gas Sales Rate 160
4810180	Comm Int Gas Sls Trans Rte 180
4810190	Comm Interruptible-cog Adj
4810200	Industrial Sales Gas
4810201	Ind Firm Gas Sls Trans Rte 200
4810202	Ind Firm Gas Sls Trans Rte 201
4810225	Ind Firm Gas Sales Rate 125
4810226	Ind Firm Gas Sales Rate 126
4810227	Ind Firm Gas Sales Rate 127
4810240	Med Gen Serv-ind Rate 140
4810245	Ind Firm Gas Sales Rate 145
4810275	Ind Firm Gas Sls Trans Rte 175
4810290	Ind Firm Gas Sales Rate 190
4810300	Industrial Sales Interupt Gas
4810350	Ind Int Gas Sales Rate 150
4810351	Ind Int Gas Sls-rt 150-demnd
4810360	Ind Int Gas Sales Rate 160
4810380	Ind Int Gas Sales Trans Rt 180
4810390	Ind Interruptible Cog Adj
4810400	Commercial
4810500	Industrial
4810600	Commercial Gas Sales Nonreg
4810700	Indstrial Gas Sales Nonreg
4820000	Oth Op Rev-sales To Pub Auth
4830000	Sale For Resale Municipal Gas
4830001	Sale-rsale Muncpl Interupt Gas
4830002	Non Assoc Sales For Resale
4830003	Municipal Gas Sales Nonreg
4830007	Revenue Sales For Resale Assoc
4830013	Sceg - Sale For Resale
4830015	Sales For Resale Non Assoc - S
4830195	Oper Rev Gas Rev Intercomp
4840000	Intrdpt Sals Gas Used-elec Gen
4840001	Interdepartmenal Sales Cng

4840100	Semi Sales To Sce&g Jasper-
4840101	Commercial - Affiliate Sales
4840102	Industrial - Affiliate Sales
4840103	Sales For Resale-affilit Sales
4840104	Municipal - Affiliate Sales
4840195	Interdepartment Gas Sales-cee
4840225	Interdptmnt Gas Sales-cee 225
4841000	Interdepartmenal Sales Sceg
4842000	Interdepartmentl Gas Nonreg
4850000	Pga Ovr/undr Collctns Oth Sals
4850100	Deferred Gas Rev
4850101	Def Gas Rev Refund
4850200	Unbill Rev Def Gas Rev
4850201	Unbill Rev Increm Gas Cost
4850300	Unbilled Gas Nonregulated
4870000	Other Oper Rev-delinquent Chgs
4870001	Assoc Sceg Delinquent Charge
4870002	Delinquent Charge - Semi
4870003	Other Oper Rev-semi Delinq Chg
4870018	Other Oper Rev-sceg Delinq Chg
4870100	Other Oper Rev-delinquent Chgs
4880000	Miscellaneous Service Revenue
4880001	Oth Oper Rev Rents From Gas
4880002	Oth Oper Rev-ciac Tax Gross-up
4880010	Miscellaneous Service Revenue
4880011	Other Oper Rev-ret Check Fee
4880012	Oth Oper Revenue-hedging Activ
4880100	Other Oper Rev-ret Check Fee
4880200	Misc Gas Service Rev Nonreg
4880300	Other Oper Rev After Hours Chg
4880500	New Meter Set Trip Charges
4880600	Investigative Charges
4890000	Rev Transp Of Gas Of Others
4890003	Rev - Semi Firm Jumper Chg
4890018	Rev Transp Associated Co Gas
4890075	Comm Firm Gas Sls-trans Rt 175
4890100	Rev Rate35 Transp & Stdby Chrg
4890180	Comm Int Gas Sls-trans Rte 180

4890200	Industrl Transprtn-scpc Custmr
4890201	Ind Firm Gas Sls-trans Rte 200
4890202	Ind Firm Gas Sls-trans Rte 201
4890203	Ind Firm Gas Sls-trans Rte 202
4890210	Transportation - Assoc Co
4890275	Ind Firm Gas Sls-trans Rte 175
4890365	Ind Int Gas Sales-trans Rt 165
4890380	Ind Int Gas Sales-trans Rte 18
4890400	Capacity Release Sharing- Sc
4890401	Cust Pass Thru Reservation Chg
4890402	Cust Pass Thru Reservation Chg
4890403	Cust Pass Thru Reservation Chg
4890404	Cust Pass Thru Transport Cha
4890405	Cust Pass Thru Transport Cha
4890406	Cust Pass Thru Transport Cha
4890407	Cust Pass Thru Cgt Reseva
4891000	Comm And Indust Transportatn
4892000	Transportation - Scpc
4892009	Non Assoc Z2-1 Ft Use Delv-sm
4892010	Non Assoc Z-1 Firm Reservation
4892011	Non Assoc Z1 Firm Usage Transp
4892013	Non Assoc Z1 Firm Usage Aca
4892019	Na Z1 Firm Usage Mt Mdtq Sm
4892020	Non Assoc Z-2 Firm Reservation
4892021	Non Assoc Z2 Firm Usage Transp
4892023	Non Assoc Z2 Firm Usage Aca
4892029	Non Asso Z2 Firm Usage Mdtq-sm
4892031	Non Assoc Z1 It Usage Transp
4892033	Non Assoc Z1 It Usage Aca
4892039	Non Assoc Z-1 It Usage (sm)
4892041	Non Assoc Z-2 It Usage Transp
4892043	Non Assoc Z-2 It Usage Aca
4892049	Non Assoc Z-2 It Usage (sm)
4892069	Non Assoc Pal 1st Day Rate(sm)
4892079	Non Assoc Pal Sub Day Rate(sm)
4892080	Na Z1 Bh Firm Reservation
4892081	Na Z1 Bh Firm Var Usage Trans
4892083	Na Z1 Bh Firm Var Usage Aca
4892110	Asso Sceg Z1 Firm Reservation
4892111	Asso Sceg Z1 Firm Usage Transp
4892113	Asso Sceg Z1 Firm Usage Aca

4892119	Asso Scegz1 Firm Usage Mdtq-sm
4892120	Asso Sceg Z2 Firm Reservation
4892121	Asso Sceg Z2 Firm Usage Transp
4892123	Asso Sceg Z2 Firm Usage Aca
4892129	Asso Scegz2 Firm Usage Mdtq-sm
4892131	Asso Sceg Z1 It Usage Transp
4892133	Asso Sceg Z1 It Usage Aca
4892139	Asso Sceg Z1 It Usage -sm
4892141	Asso Sce&g Z2 It Usage
4892143	Asso Sce&g Z2 It Usage Aca
4892149	Asso Sce&g Z2 It Usage -sm
4892169	Asso Sceg Pal 1st Day Rate-sm
4892179	Asso Sceg Pal Sub Day Rate-sm
4892209	Asso Semi Z2-1 Ft Use Delv -sm
4892210	Asso Semi Z1 Firm Reservation
4892211	Asso Semi Z1 Firm Usage Transp
4892213	Asso Semi Z1 Firm Usage Aca
4892219	Asso Semi Z1 Firm Usgae Mdtq-s
4892220	Asso Semi Z2 Firm Reservation
4892221	Asso Semi Z2 Firm Usage Transp
4892223	Asso Semi Z2 Firm Usage Aca
4892229	Asso Semi Z2 Firm Usage Mdtq S
4892231	Asso Semi Z1 It Usage Transp
4892233	Assoc Semi Z 1 It Usage Aca
4892239	Asso Semi Z1 It Usage Sm
4892241	Asso Semi Z2 It Usage
4892243	Assoc Semi Z2 It Usage Aca
4892249	Asso Semi Z2 It Usage -sm
4892259	Asso Semi St Z-1 Firm Res
4892269	Asso Semi Pal 1st Day Rate-sm
4892279	Asso Semi Pal Sub Day Rate-sm
4892400	Scg - Aca Revenue - Assoc
4892410	Non Assoc Discounted Ft Reserv
4892419	Non Ass Second Pt Z1 Ft Use-sm
4892429	Non Ass Alt Del Pt Z2 Ftuse-sm
4892510	Non Assoc St Z-1 Firm Reservtn
4892511	Non Assoc St Z1 Firm Usage Trn
4892513	Non Assoc St Z1 Firm Usage Aca

4892519	Non Assoc St Z1 Frm Usage Mdtq
4892680	Na Z1 Bh Neg Firm Reservation
4892682	Na Z1 Bh Neg Z1 Transportation
4892758	Non Assoc Ft Contract Revenue
4892858	Non Assoc Cec Gross Revenue
4892859	Non Assoc Ft Contract Revenue
4892958	Nonassc Cec Gross Rev Contra
4893000	Transportation Scpc-sale For R
4894000	Transportation Scpc-industrial
4930000	Rent From Gas Property
4930001	Facility Charge Revenues - Non
4930002	Rent Gas Prop Lady St Semi
4930003	Rent Gas Prop Salley Cgtc
4950000	Other Gas Revenues
4950001	Gain Loss Fr Disp Of Util Prop
4950010	Other Gas Revenues
4950011	Sega Retail Benefit Commission
4950018	Oth Gas Rev-associated W Gas
4950040	Agl Rider Charges
4950100	Standby Charges Oth Gas Rev
4950110	Trade Discounts
4950140	Agl Rider Charges
4950200	Recovry-scpc Chrgs Oth Gas Rev
4950210	Other Gas Revenues-sales Tax D
4950250	Other Gas Revenues-cec Gross R
4950255	Other Gas Revenues-cec Gross R
4960000	Provision For Rate Refund
4990000	Cum Pfd Stk.-is Line
4990001	Dum Pfd Stk-is Line Contra
4990002	Dum Pfd Stk-bs Reversal
4990003	Dum Pfd Stk-bs Rever Contra
5000000	Oper Superv And Eng Steam Pwr
5010000	Oper Fuel Steam Pwr
5010002	Fuel Expense Ferc Adjustment
5010099	Chemicals - Fuel Clause
5010100	Fuel Handling Exp Steam Pwr
5010200	Fuel Exp-nndeadhead Billing
5020000	Oper Steam Expenses Steam Pwr

5040000	Oper Steam Transfrrd Steam Pwr
5050000	Oper Elec Expenses Steam Pwr
5060000	Op Msc Steam Pwr Exp Steam Pwr
5070000	Oper Rents Steam Pwr
5090001	Allowances Expensed
5091010	Oper So2 Arp Allow Exp
5091011	Oper S02 Csapr Allow Exp
5091020	Oper Nox Ozone Cair Expense
5091021	Oper Nox Ozone Csapr Exp
5091030	Oper Nox Annual Cair Exp
5091031	Oper Nox Annual Csapr Exp
5100000	Maint Superv And Eng Steam Pwr
5110000	Maint Structures Steam Pwr
5120000	Maint Boiler Plant Steam Pwr
5130000	Maint Elec Plant Steam Pwr
5140000	Maint Msc Steam Plnt Steam Pwr
5170000	Oper Superv And Eng Nuc Pwr
5180000	Oper Nuc Fuel Exp Nuc Pwr
5180001	Op Nuc Fuel Doe Settle
5190000	Oper Coolants & Water Nuc Pwr
5200000	Oper Steam Expenses Nuc Pwr
5230000	Oper Elec Expenses Nuc Pwr
5240000	Oper Misc Nuc Pwr Exp Nuc Pwr
5240100	Op Msc Nu Pwr Decom Exp Nu Pwr
5240200	Oper Refuel Reserve Nuc Pwr
5280000	Maint Superv & Engnrng Nuc Pwr
5280100	Maint Refueling Reserve Nu Pwr
5290000	Maint Structures Nuc Pwr
5300000	Maint Reactr Plnt Equip Nu Pwr
5310000	Maint Elec Plant Nuc Pwr
5310001	Maint Elec Plant Nucl-bus Tie
5320000	Maint Misc Nuc Plant Nuc Pwr
5320001	Maint Misc Nuc Plnt-fib Opt-bt
5350000	Oper Superv And Eng Hydro Pwr
5360000	Oper Water For Power Hydro Pwr
5370000	Oper Hydraulic Exp Hydro Pwr

5370100	Oper Fish & Wildlife Hydro Pwr
5370200	Oper Recreationl Fac Hydro Pwr
5370300	Oper Lake Murray Mgt Hydro Pwr
5370301	Op Lake Montcllo Mgt Hydro Pwr
5370400	Oper Timber Sales Hydro Pwr
5380000	Oper Elec Expenses Hydro Pwr
5390000	Op Msc Hydrlc Pwr Gen Hydr Pwr
5400000	Oper Rents Hydro Pwr
5410000	Maint Superv And Eng Hydro Pwr
5420000	Maint Structures Hydro Pwr
5430000	Maint Rrvr Dams & Wtrwys Hydr
5440000	Maint Elec Plant Hydro Pwr
5450000	Maint Msc Hydrlc Plt Hydro Pwr
5450100	Maint Fish & Wildlf Hydro Pwr
5450200	Maint Recrtnl Faclts Hydro Pwr
5460000	Oper Superv & Enginrng Oth Pw.
5470000	Oper Fuel Oth Pwr
5470001	Oper Fuel Handlng Gas Turbines
5470300	Fuel - Scg It Revenue Sharing
5480000	Oper Generation Exp Oth Pwr
5490000	Op Msc Oth Prw Gen Exp Oth Pwr
5500000	Oper Rents Oth Pwr
5510000	Maint Superv And Eng Oth Pwr
5520000	Maint Structures Oth Pwr
5530000	Maint Gen & Elec Plant Oth Pwr
5530001	Jasper Csa Maint Gen&elec Plnt
5530002	Urquhart - Ge Csa Maintenance
5540000	Maint Msc Oth Pwr Gen Plnt Pwr
5550000	Pur Pwr Non Assoc Oth Pwr Sup
5550001	Pur Pwr Assoc Co Oth Pwr Sup
5550002	Pur Pwr From Genco - Deferred
5550003	Purchased Power - Pr1 Customer
5550004	Prch Pwr - Amort Of Def Exps
5550005	Prch Pwr - Mjm Accrual Act Rev

5550006	Purch Pwr-der-solar-avoided
5550007	Purch Pwr-der-solar-incrementa
5550008	Purch Pwr-der-solar-avo-contra
5550009	Purch Pwr-der-solar-inc-contra
5550010	Pur Pwr Non Der Solar
5550100	Pur Pwr Pwr Sup Nmst & Emerg
5550200	Prch Pwr - Amort Def Capacity
5550201	Prch Pwr - Long-term Ppa
5560000	Sys Cntrl & Load Dsptch Pwr
5570000	Other Expenses Oth Pwr Supply
5570100	Stndby Gen Stndby Fees Pwr Sup
5570101	Stndby Gen Fuel-maint Supp Oth
5600000	Oper Supervsn & Enginrng Tran
5610000	Oper Load Dispatching Trans
5611000	Load Dispatch-reliability
5612000	Load Dispatch-monitor And Oper
5613000	Load Dispatch-trans Serv And S
5615000	Relia Planning And Stndrd Deve
5616000	Transmission Service Studies
5617000	Generation Interconnect Studie
5620000	Oper Station Expenses Trans
5630000	Oper Oh Line Expenses Trans
5640000	Oper Undrgrnd Line Exp Trans
5650000	Oper Trans-elec By Others Tran
5660000	Oper Misc Trans Exps Trans
5660100	Op Trans Impct Stud Natve Load
5660200	Oper Redispatch Expense Trans
5660300	Op Trans Exp Impct Stud-nw Sls
5660400	Oper-amort Of Gridsouth Reg As
5670000	Oper Rents Trans
5680000	Maint Super & Enginrng Trans
5690000	Maint Structures Trans
5690100	Maint Struct Relay-cntrl Bldg
5691000	Maint Of Computer Hardware
5692000	Maint Of Computer Software
5693000	Maint Of Communication Equip
5700000	Maint Station Equip Trans

5700001	Maint Statn Equ Ctrl & Instrmt
5700002	Maint Statn Equ Dc Sys Nu Tran
5700003	Maint Statn Equ Ug Cble & Cndt
5710000	Maint Overhead Lines Trans
5710001	Storm Damage - Reserve
5720000	Maint Underground Lines Trans
5730000	Maint Misc Transm Plnt Trans
5730001	Maint Misc Trans Pl-enrnmntl
5800000	Dist Oper Superv & Engineering
5810000	Dist Oper Load Dispatch
5820000	Dist Oper Stat Expenses
5830000	Dist Oper Oh Line Expenses
5830001	Dist Op Remv & Reset Oh Trans
5830002	Dist Op Remv & Reset Pdmnt Tra
5840000	Dist Oper Undergrnd Line Exp
5840001	Dist Oper Netwk Transformers
5840002	Dist Op Remv & Reset Submersbl
5850000	Dist Op St Light & Sgnl Sys Ex
5860000	Dist Oper Meter Expenses
5870000	Dist Oper Cust Install Exp
5870001	Dist Op Cust Instl Exp Bill
5870002	Dist Cust Instl Amt Bill Cust
5880000	Dist Oper Misc Distrib Expns
5880001	Dist Oper Environ Expenses
5890000	Dist Oper Rents
5900000	Dist Maint Superv & Engineerng
5910000	Dist Maint Structures
5920000	Dist Maint Of Stat Equipment
5920001	Maint Stat Equip-environmental
5930000	Dist Maint Oh Lines
5930001	Rights Of Way Re
5930002	Oh Lines Storm Dam Res Re
5940000	Dist Maint Undergrnd Lines
5950000	Dist Maint Line Transformers
5950001	Dist Maint Netwk Transformers
5950002	Dist Maint Submers Transfrmrs
5950003	Dist Maint Padmtd Transformers
5960000	Dist Maint St Light & Sgnl Sys
5970000	Dist Maint Meters
5980000	Dist Maint Misc Distrib Plant

7100000	Oper Supervision And Engr Mgp
7170000	Oper Liq Petroleum Gas Exp Mgp
7280000	Liq Petroleum Gas Fuel Mgp
7350000	Envir Amrt & Misc Oper Exp Mgp
7410000	Maint Struct And Impr Mgp
7420000	Maint Production Equip Mgp
8030000	Natural Gas Purch-resale Fuel
8030007	Gas - Assoc Co
8030100	Ng Purch From Transpr Customrs
8030200	Gas-elec Genrtn Cr Ng Oper
8030300	Cng Station Purchases Ng Oper
8030310	Gas Upstream It Rev Sharing
8030400	Gas Purch For Resale Nonreg
8030401	Transportation - Assoc Co
8030402	Cost Of Gas - Aca Chgs Assoc
8030403	Cost Of Gas - Assoc Co - Semi
8030404	Regulated Gas - Aca Charges
8030420	Elimination Account With Cgt
8030450	Semi Cost Of Gas -commodity
8030451	Cost Of Gas Re-accrual Adj
8030455	Semi Cost Of Gas -resrvation A
8030460	Semi Cost Of Gas-transportatio
8030461	Semi Cost Of Gas-storage Charg
8030462	Semi Cost Of Gas-cust Pass Thr
8030463	Agl Marketer True-up
8030464	Agl Marketer Prior Month True-
8030470	Semi Cost Of Gas -commodity
8030480	Elimination Account With Cgt
8030481	Agl Gas Charges
8030482	Agl Demand Chrgs-residential
8030483	Franchise Tax - Cog
8030484	Cost Of Gas - Agl Base Charges
8030485	Semi Cost Of Gas
8030486	Agl Peaking Reservation
8030487	Agl Service Order Charges
8030488	Property Tax Accruals-inventor
8030490	Semi Hedging Gains And Losses
8030491	Unrealized Gain Loss Petal Sto
8030510	Pipeline Fixed Charges
8030520	Ng Trans Line Purch Interco
8030550	Commodity Purchases
8030576	Income-customer Futures Orders

8030582	Cola Hca Option Mtm
8030590	Realized Hedge Gain
8030592	Unrealized Hedge Gain-
8030610	Ng Demand Transco
8030620	Ng Commodity Transco
8030630	Ng Transportation Transco
8030717	Ng Demand Assoc Co Cgtc
8030737	Ng Transp Assoc Co Cgtc
8030810	Ng Demand Sonat
8030820	Ng Commodity Sonat
8030830	Ng Transpoprtation Sonat
8030910	Ng Demand Semi
8030920	Ng Commodity Semi
8040000	Ng City Gate Purch Oth Rec
8050000	Other Gas Purchases
8070000	Purchased Gas Expenses Ng Oper
8080000	Gas Withdrawn Or Delivered To
8081010	Lng Storage Charges-fixed
8081011	Gas Wd Frm Stor Transco Gss
8081013	Gas Wd Frm Stor Transco Wss
8081015	Gas Wd Frm Stor Saltville
8081017	Gas Wd Frm Stor Dti Gss
8081018	Gas Wd Frm Stor Transco Ess
8081019	Gas Wd Frm Stor - Eminence
8081020	Lng Storage Charges-volumetric
8081021	Gas Wd Frm Stor Transco Lga
8081023	Gas Wd Frm Stor-cove Point
8081024	Gas Wd Frm Stor Cola Fss
8081025	Gas Wd Frm Stor-pine Needle
8081031	Gas Wd Frm Stor-psnc Cary
8081050	Storage Charges - Fixed
8081051	Gas Wd Frm Stor Trans Gss
8081052	Gas Wd Frm Stor Trans Wss
8081053	Stored Gas Demand Chrg Dti Gss
8081054	Gas Wd Frm Stor Trans Ess
8081055	Demand Charges - Saltville
8081056	Lng-cary Power Costs
8081058	Gas Wd Frm Stor Cola Fss
8081060	Storage Charges - Volumetric
8081061	Gas Wd Frm Stor Trans Lga
8082011	Gas Delv To Stor Transco Gss
8082013	Gas Delv To Stor Transco Wss
8082015	Gas Delv To Stor Saltville

8082017	Gas Delv To Stor Dti Gss
8082018	Gas Delv To Stor Transco Ess
8082019	Gas Delv To Stor - Eminence
8082021	Gas Delv To Stor Transco Lga
8082023	Gas Delv To Stor- Cove Point
8082024	Gas Delv To Stor Columbia
8082025	Gas Delv To Stor -pine Needle
8082031	Gas Delv To Stor-psnc Cary
8090000	Lng Withdrawn Or Delivered To
8091010	Lng Storage Charges-fixed
8091020	Lng Storage Charges-volumetric
8091023	Lng Wd Cove Point
8091025	Lng Wd Pine Needle
8091031	Lng Wd Withdrawal
8091056	Lng - Cary Power Costs
8091057	Lng Wd Cove Point
8092023	Lng Delivery Cove Point
8092025	Lng Delivery Pine Needle
8092031	Lng Delivery Injections
8100000	Gas-for Comp Station Fuel-crdt
8120000	Gas-for Other Utlty Oper-crdt
8130000	Oth Gas Supply Expns Ng Oper
8130001	Fac Chrg Oth Gas Supp Exp
8130002	Gas Cost Oth Gas Supp Exp
8130003	Cost Of Un Oth Gas Supp Exp
8130004	Other Gas Supply Exp
8130005	Lost And Unaccounted For
8130010	Other Gas Supply Exp-non Reg
8400000	Oper Supr & Engr Oth Stor Exp
8410000	Oper Labor & Exp Oth Stor Exp
8410001	Oper Refrigerants Oth Stor Exp
8410002	Oper Lubricants Oth Stor Exp
8410003	Oper Oth Consum Oth Stor Exp
8410004	Oper Exp Oth Stor Exp
8410005	Oper Transp Labor And Expenses
8410006	Oper Vapor Labor And Expenses
8410007	Oper Liquefac Labor And Expens
8420000	Oper Rents Oth Stor Exp
8421001	Oper Fuel Ng Oth Stor Exp
8421002	Oper Fuel Oil Oth Stor Exp
8422000	Oper Power Oth Stor Exp
8423000	Oper Gas Loss Unaccntd For Gas

8431000	Maint Supervision And Engineer
8432000	Maint Struct & Impr Oth Stor
8433000	Maint Gas Holders Oth Stor Exp
8434000	Maint Purificatn Equip Oth Sto
8435000	Maint Liquefaction Oth Stor
8436001	Maint Vaporizing Equip Boilers
8436002	Maint Vaporizing Equip Liq Pum
8436003	Maint Vaporizing Equip Other
8437001	Maint Compressor Equip C1
8437002	Maint Compressor Equip C2
8437003	Maint Compressor Equip C3
8437004	Maint Compressor Equip C4
8437005	Maint Compressor Equip Air
8437006	Maint Compressor Equip Vapor
8437007	Maint Compressor Equip Other
8437008	Maint Transportation Equpment
8437009	Maint Communication Equipment
8438000	Maint Measuring & Reg Equip
8439000	Maint Other Equip Oth Stor
8441000	Lng - Operation
8442000	Lng Operation- Labor And Expen
8443000	Lng Operation-liquif Proc Lbr
8444100	Lng-transp Labor & Exp-bushy
8444200	Lng-transp Labor & Exp-salley
8445000	Lng Operation -m And R Labor A
8446000	Lng Operation-compressor Labor
8447000	Lng Operation-communication Sy
8451000	Lng Operation-communication Sy
8452000	Lng Operation-power
8461000	Lng Operations-gas Losses
8462000	Lng Operation-other Expenses
8471000	Lng - Maintenance
8472000	Lng Maintenance-struct And Imp
8473000	Lng Maintenance-proc Term Equp
8474000	Lng Maintenance-transp Equip

8475000	Lng Maintenance-m And R Equip
8476000	Lng Maintenance-compressor Eqp
8477000	Lng Maintenance-comm Equip
8478000	Lng Maintenance-other Equip
8500000	Oper Supervsn & Engineering
8510000	Syst Cntrl And Load Disptch
8510003	System Control-t-1 Phones Sall
8520000	Oper Comm Sys Exp Trans Exp
8530000	Oper Commpressor Station Exp
8540000	Gas For Compressor Station Fue
8560000	Oper Mains Exp Transmission
8560100	Oper Mains Exp Transmiss Row
8560101	Right Of Way Mowing
8560102	Right Of Way Swamp Maintenance
8560103	Right Of Way Valve Move And Lu
8560104	Row Maintenance Marketers
8560105	Row Miscellaneous Maintnance
8560106	Right Of Way Training
8560107	Right Of Way Mowing Facilities
8570000	Oper Meas & Reg Stations Exp
8590000	Oper Other Transmission Exp
8600000	Oper Rents Transmission Exp
8610000	Maint Supervision & Enginrng
8620000	Maint Struct & Impr Trans Exp
8630000	Maint Mains Transmission Exp
8640000	Maint Compressor Stat Trans Ex
8650000	Maint Meas & Reg Stat Equip
8660000	Maint Comm Equip Trans Exp
8670000	Maintenace Of Other Equipment
8700000	Supervsn & Engr Ng Dist Oper
8710000	Load Dispatching Ng Dist Oper
8740000	Mains & Srvcs Exp Ng Dist Oper
8750000	Meas/reg Statn Exp Gnrl Ng Dst
8760000	Meas/reg Statn Exp Indstl Ng D
8780000	Meter/house Reg Exp Ng Dist Op
8780020	Oper Meter House Reg Pre Fab
8780030	Oper Meter House Reg Install
8790000	Cust Installation Ng Dist Oper
8790001	Cust Instl Bill Exp Ng Dist

8790002	Instl Amt Bill Cust Cr Ng Dst
8790003	Gwh Net Warranty Expense
8800000	Other Expenses Ng Dist Oper
8810000	Rents Ng Dist Oper
8850000	Maint Supervsn & Engr Ng Dist
8860000	Maint Strctr & Imprvmnt Ng Dis
8870000	Maint Mains Ng Dist
8890000	Maint Meas/reg Statn Equ Genrl
8900000	Maint Meas/reg Statn Equ Indst
8920000	Maint Services Ng Dist
8930000	Maint Metrs/house Regtr Ng Dis
8940000	Maint Other Equipment Ng Dist
9010000	Supervision Cust Acct
9020000	Meter Reading Exp Cust Acct
9030001	Billing & Accntng Exp Cust Act
9030002	Collecting Exp Cust Acct
9030003	Contrct & Orders Exp Cust Acct
9030004	Customer Records And Collect E
9040000	Uncollectbl Accnts Cust Acct
9040001	Uncollectible Accts - Calpine
9040002	Uncoll Acct Cust-georgia Unbl
9040003	Uncoll Acct Cust-georgia Seb
9040004	Uncoll Acct Cust-ga Unbill Agl
9040005	Uncoll Acct Cust-ga Seb Segr
9050000	Misc Cust Accnts Exp Cust Acct
9050001	Uncollectible Accts - Calpine
9070000	Supervision Cust Serv
9080000	Customr Assistnc Exp Cust Srv
9080001	Rebates Cust Serv
9080002	Demand Side Mgmt Cust Serv
9080003	Cust Acctg Courtesy Adjustmnts
9080004	Amortization - Demand Side Mgm
9090000	Info/instrct Advert Ex Cst Srv
9100000	Misc Cust Srv/info Exp Cus
9110000	Supervision Sales
9120000	Demonstrtng & Sellng Exp Sales
9120001	Demo & Selling Exp Psnc Oth
9120002	Demo & Selling Exp Psnc Sal
9120003	Demo & Selling Exp Psnc Exp
9130000	Advertising Exp Sales
9130001	Advert Exp Psnc Misc

9130002	Advert Exp Psnc Residential
9130003	Advert Exp Psnc Commercial
9130004	Advert Exp Psnc Industrial
9130005	Advert Exp Psnc Trade
9160000	Misc Sales Exp Sales
9200000	A And G Salaries
9200001	Accrue Vacation Carryover
9200003	A And G Salaries Bonus
9210000	A And G Off Supp And Expenses
9210001	A&g Sal Psnc Scana Ohs
9210999	A And G Off Sup Ex Btl Trnf
9220000	A And G Admn Exp Trns Cr
9230000	A And G Outside Svcs
9230001	A And G Out Svcs Scana Ovhds
9230004	A&g Out Svcs Wesths Lit Amort
9230091	Outside Serv-scana-disputed
9230092	Outside-serv-holding Co O/h
9240000	A And G Property Insurance
9250000	A And G Injuries And Damages
9250001	A&g Inj & Dam Psnc Exc Gen Lai
9250002	A&g Inj & Dam Psnc Work Comp
9250003	A&g Inj & Dam Psnc Crime & Fid
9250004	A&g Inj & Dam Psnc Dir Off Lia
9250005	A&g Inj & Dam Psnc Fid & Emp
9250006	A&g Inj & Dam Psnc Workpl Viol
9260000	A And G Pension
9260001	A And G Benefits
9260002	A And G Pens And Bene Vcs Opeb
9260003	A And G Psa Balancing For Pb&t
9260004	Retail Electric Pension Rider
9260005	Non Retail Electric Pension Ex
9260006	Electric Pension Non Service C
9260007	Gas Pension Non Service Cost -
9270000	A And G Franch Requirements
9280000	A And G Reg Comm Exps
9280001	A&g Reg Comm Exps Scana Ovhds
9280002	A&g Reg Comm Exp Psnc Fees
9280200	Regulatory Commission Exp-ferc
9280210	Ferc Aca Charges
9290000	A And G Duplicate Chgs Cr

9300100	General Advertising Expenses
9301000	A And G Gen Advert Exps
9302000	A And G Misc Gen Exps
9302001	A&g Misc Gen Exps Scana Ovhds
9310000	A And G Rents
9310002	Office Space Rental Lady Stree
9310010	Leases-communications Equipmnt
9310015	Rents - Aircraft
9310020	Other Leases And Rentals
9320000	Maintenace Of General Plant
9350000	A And G Maint General Plant
9350001	A And G Environ Exp
9350010	Maint - Transportation And Poe
9350020	Maint Of Communication Eqpmnt
9350030	Maint Of Office Furn And Equip
9350040	Maintenance Of Other Equipment
9777777	Consolidations Suspense Acct
9999999	Retained Earn Contra

SOUTH CAROLINA ELECTRIC & GAS
OFFICE OF REGULATORY STAFF AUDIT INFORMATION REQUEST
DOCKET 2017-207-E, 2017-305-E, 2017-370-E

RESPONSE NO. 1-24

Balance Sheet Reconciliation to Exhibit 14,15,16,17

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
Total Assets and Other Debits	1. Utility Plant Net	1. Utility Plant	1010100 Elec Plant In Service	8,990,309,427	-	8,990,309,427	9,039,622,434	49,313,008	Difference is related to Fleet. The Fleet business unit is not reflected on the Electric B/S. It is reflected on the SCE&G B/S
			1010160 - Electric - Plant In Service-de	3,213,243	-	3,213,243	-	(3,213,243)	Not included in Rate Base
			1010180 Elec Pis For Arc- Non Ratebase	15,285,635	-	15,285,635	-	(15,285,635)	Not included in Rate Base
			1060100 Compl Constr Not Classfd Elec	450,338,149	-	450,338,149	450,338,149	-	
			1060160 - Elect-completed Constr No Clas	490,525	-	490,525	-	(490,525)	Not included in Rate Base
			1140000 Elec Plant Acq Adj	1,981,659	-	1,981,659	-	(1,981,659)	Not included in Rate Base
			1140003 Elec Plt Acq Adj Hagood Lm2500	21,100,783	-	21,100,783	21,100,783	-	
			1140004 Elec Plt Acq Adj Hagood Tm2500	8,278,384	-	8,278,384	8,278,384	-	
			1180710 Common Plant in Service	-	-	-	319,311,869	319,311,869	Electric Portion of Common is calculated from SCE&G B/S
			1180760 Common Compl Constr not Classfd	-	-	-	9,110,972	9,110,972	Electric Portion of Common is calculated from SCE&G B/S
		1. Utility Plant Total		**9,490,997,804**	**-**	**9,490,997,804**	**9,847,762,591**		
		2. Accum Depreciation/Amortizatn	1080100 Acc Depr Rwip Elec	56,447,809	-	56,447,809	56,447,809	-	
			1080101 - Accum Depr Salv Elec	(1,183,807)	-	(1,183,807)	(1,181,467)	2,340	Difference is related to Fleet. The Fleet business unit is not reflected on the Electric B/S. It is reflected on the SCE&G B/S
			1080110 Acc Depr Of Elec Utility Plant	(2,943,438,106)	-	(2,943,438,106)	(2,980,602,674)	(37,164,568)	Difference is related to Fleet. The Fleet business unit is not reflected on the Electric B/S. It is reflected on the SCE&G B/S
			1080112 - Accum Depr Cor Electric	(462,589,936)	-	(462,589,936)	(462,589,936)	-	
			1080120 Acc Depr Of Elect Ut Plt - Aro	(14,348,626)	-	(14,348,626)	-	14,348,626	Not included in Rate Base
			1080150 Acc Depr Elec Ut Plt - Synfuel	(263,885,659)	-	(263,885,659)	(263,885,659)	-	
			1080160 - Der Capital - Incremental	(222,388)	-	(222,388)	-	222,388	Not included in Rate Base
			1080180 Accum Depr Electric Pis - Arc	(28,935,762)	-	(28,935,762)	-	28,935,762	Not included in Rate Base
			1110000 Acc Amort-elec Utility Plant	(63,718,082)	-	(63,718,082)	(63,718,082)	-	
			1110160 - Acc Amort-electric Utility Pla	(26,376)	-	(26,376)	-	26,376	Not included in Rate Base
			1150000 Acc Amort-elec Plant Acq Adj	(1,981,659)	-	(1,981,659)	-	1,981,659	Not included in Rate Base
			1150003 Acc Amor Acq Adj Hagood Lm2500	(3,720,541)	-	(3,720,541)	(3,720,541)	-	
			1150004 Acc Amor Acq Adj Hagood Tm2500	(1,459,665)	-	(1,459,665)	(1,459,665)	-	
			1190770 Acc Depr Of Common Utility Pl	(20,033)	-	(20,033)	(140,637,719)	(140,617,686)	Electric Portion of Common is calculated from SCE&G B/S
			1190773 Accum Depr for Amrt Metroplex	-	-	-	(2,048,383)	(2,048,383)	Electric Portion of Common is calculated from SCE&G B/S
			1190774 Accum for Depr Chas Flex	-	-	-	(280,593)	(280,593)	Electric Portion of Common is calculated from SCE&G B/S
			1190775 - Accum Depr Cor Common		-		(2,229,184)	(2,229,184)	Electric Portion of Common is calculated from SCE&G B/S
			1190710 Common RWIP	-	-	-	248,137	248,137	Electric Portion of Common is calculated from SCE&G B/S
		2. Accum Depreciation/Amortizatn Total		**(3,729,082,830)**	**-**	**(3,729,082,830)**	**(3,865,657,956)**		
		3. Construction Work in Progress	1070100 Constr Work In Prog Elec	5,042,664,283	-	5,042,664,283	5,042,697,514	33,231	Difference is related to Fleet. The Fleet business unit is not reflected on the Electric B/S. It is reflected on the SCE&G B/S
			1180770 Common CWIP	-	-	-	1,498,187	1,498,187	Electric Portion of Common is calculated from SCE&G B/S
		3. Construction Work in Progress Total		**5,042,664,283**	**-**	**5,042,664,283**	**5,044,195,701**	**1,531,418**	
		4. Nuclear Fuel Net	1201002 Nf In Proc Batch Tbd-conversio	-	-	-	-		
			1201004 Nf In Proc Batch Tbd-fabricat	-	-	-	-		
			1201005 Nf In Proc Batch Tbd-afudc	-	-	-	-		
			1201232 Nf In Proc Batch 23 Conversion	-	-	-	-		
			1201272 - Nf In Proc Batch 27 Conversion	-	5,751,893	5,751,893	-		
			1201275 - Nf In Proc Batch 27 Afudc	-	85,376	85,376	-		
			1202002 Nuclear Fuel Stock-conversion	-	62,674,450	62,674,450	-		
			1202003 - Nuclear Fuel Stock-enrichment	-	76,881,148	76,881,148	-		
			1202004 - Nuclear Fuel Stock-fabrication	-	2,574,132	2,574,132	-		
			1202005 - Nuclear Fuel Stock-afudc	-	6,154,431	6,154,431	-		
			1203203 Nf In Reactor Batch 20 Enrich	-	-	-	-		
			1203204 Nf In Reactor Batch 20 Fabric	-	-	-	-		
			1203205 Nf In Reactor Batch 20 Afudc	-	-	-	-		
			1203212 Nf In Reac Btch 21 Conv	-	-	-	-		
			1203213 Nf In Reac Btch 21 Enr	-	-	-	-		
			1203214 Nf In Reac Btch 21 Fab	-	-	-	-		
			1203215 Nf In Reac Btch 21 Afc	-	-	-	-		
			1203222 Nf In Reactor Batch 22 Conver	-	-	-	-		
			1203223 Nf In Reactor Batch 22 Enrich	-	-	-	-		
			1203224 Nf In Reactor Batch 22 Fabric	-	-	-	-		
			1203225 Nf In Reactor Batch 22 Afudc	-	-	-	-		
			1203242 - Nf In Reactor Batch 24 Conver	-	43,028,887	43,028,887	-		
			1203243 - Nf In Reactor Batch 24 Enrich	-	18,100,223	18,100,223	-		
			1203244 - Nf In Reactor Batch 24 Fabric	-	6,779,894	6,779,894	-		
			1203245 - Nf In Reactor Batch 24 Afudc	-	139,096	139,096	-		
			1203252 - Nf In Reactor Batch 25 Conver	-	44,600,733	44,600,733	-		
			1203253 - Nf In Reactor Batch 25 Enrich	-	23,839,791	23,839,791	-		
			1203254 - Nf In Reactor Batch 25 Fabric	-	7,392,670	7,392,670	-		
			1203255 - Nf In Reactor Batch 25 Afudc	-	387,761	387,761	-		
			1203262 - Nf In Reactor Batch 26 Conver	-	38,493,440	38,493,440	-		
			1203263 - Nf In Reactor Batch 26 Enrich	-	25,246,899	25,246,899	-		
			1203264 - Nf In Reactor Batch 26 Fabric	-	6,929,696	6,929,696	-		

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			1203265 - Nf In Reactor Batch 26 Afudc	-	558,926	558,926	-		
			1204000 Spent Nuclear Fuel	-	503,692,514	503,692,514	-		
			1204203 - Spent Nf Batch 20 Enrichment	-	23,146,815	23,146,815	-		
			1204204 - Spent Nf Batch 20 Fabrication	-	6,916,657	6,916,657	-		
			1204205 - Spent Nf Btch 20 Afudc	-	90,183	90,183	-		
			1204212 - Spent Nf Batch 21 Conv	-	36,205,137	36,205,137	-		
			1204213 - Spent Nf Batch 21 Enri	-	18,571,654	18,571,654	-		
			1204214 - Spent Nf Batch 21 Fabr	-	7,405,200	7,405,200	-		
			1204215 - Spent Nf Btch 21 Afudc	-	2,633,560	2,633,560	-		
			1204222 - Spent Nf Batch 22 Conversion	-	49,905,188	49,905,188	-		
			1204223 - Spent Nf Batch 22 Enrichment	-	19,493,827	19,493,827	-		
			1204224 - Spent Nf Batch 22 Fabrication	-	5,816,057	5,816,057	-		
			1204225 - Spent Nf Batch Afudc	-	117,034	117,034	-		
			1204232 - Spent Nf Batch 23 Conversion	-	52,547,467	52,547,467	-		
			1204233 - Spent Nf Batch 23 Enrichment	-	19,151,939	19,151,939	-		
			1204234 - Spent Nf Batch 23 Fabrication	-	7,426,756	7,426,756	-		
			1204235 - Spent Nf Batch 23 Afudc	-	328,667	328,667	-		
			1205000 Acc Pro Nuclear Fuel Amort	-	(503,692,514)	(503,692,514)	-		
			1205203 - Acc Prov Nf Amort 20 Enrichmnt	-	(23,146,815)	(23,146,815)	-		
			1205204 - Acc Prov Nf Amort 20 Fabricat	-	(6,916,657)	(6,916,657)	-		
			1205205 - Acc Prov Nf Amort 20 Afudc	-	(90,183)	(90,183)	-		
			1205212 - Ac Pro Nf Amort 21 Con	-	(36,205,137)	(36,205,137)	-		
			1205213 - Ac Pro Nf Amort 21 Enr	-	(18,571,654)	(18,571,654)	-		
			1205214 - Ac Pro Nf Amort 21 Fab	-	(7,405,200)	(7,405,200)	-		
			1205215 - Ac Pro Nf Amort 21 Afc	-	(2,633,560)	(2,633,560)	-		
			1205222 - Acc Prov Nf Amort #22 Conversi	-	(49,905,188)	(49,905,188)	-		
			1205223 - Acc Prov Nf Amort #22 Enrich	-	(19,493,827)	(19,493,827)	-		
			1205224 - Acc Prov Nf Amort #22 Fabricat	-	(5,816,057)	(5,816,057)	-		
			1205225 - Acc Prov Nf Amort #22 Afudc	-	(117,034)	(117,034)	-		
			1205232 - Acc Prov Nf Amort #23 Conversi	-	(52,547,467)	(52,547,467)	-		
			1205233 - Acc Prov Nf Amort 23 Enrich	-	(19,151,939)	(19,151,939)	-		
			1205234 - Acc Prov Nf Amort 23 Fabrica	-	(7,426,756)	(7,426,756)	-		
			1205235 - Acc Prov Nf Amort 23 Afudc	-	(328,667)	(328,667)	-		
			1205242 - Acc Prov Nf Amort #24 Conversi	-	(41,278,073)	(41,278,073)	-		
			1205243 - Acc Prov Nf Amort 24 Enrich	-	(17,362,869)	(17,362,869)	-		
			1205244 - Acc Prov Nf Amort 24 Fabrica	-	(6,485,742)	(6,485,742)	-		
			1205245 - Acc Prov Nf Amort 24 Afudc	-	(133,398)	(133,398)	-		
			1205252 - Acc Prov Nf Amort #25 Conversi	-	(27,688,194)	(27,688,194)	-		
			1205253 - Acc Prov Nf Amort#25 Enrich	-	(14,799,741)	(14,799,741)	-		
			1205254 - Acc Prov Nf Amort#25 Fabrica	-	(4,460,702)	(4,460,702)	-		
			1205255 - Acc Prov Nf Amort#25 Afudc	-	(240,488)	(240,488)	-		
			1205262 - Acc Prov Nf Amort 26 Convers	-	(4,381,642)	(4,381,642)	-		
			1205263 - Acc Prov Nf Amort 26 Enrich	-	(2,873,811)	(2,873,811)	-		
			1205264 - Acc Prov Nf Amort 26 Fabric	-	(788,179)	(788,179)	-		
			1205265 - Acc Prov Nf Amort 26 Afudc	-	(63,621)	(63,621)	-		
		4. Nuclear Fuel Net Total		**-**	**249,062,987**	**249,062,987**	**258,391,568**	**9,328,581**	**Nuclear Fuel is included in the Materials & Supplies total using a 12 month average balance**
	1. Utility Plant Net			**10,804,579,257**	**249,062,987**	**11,053,642,244**	**11,284,691,904**		
	2. Other Property and Investment	1. Nonutility Property	1210100 Nonutility Property	5,678	-	5,678	-		
			1210700 Constr Work In Prog Non Util	-	-	-	-		
		1. Nonutility Property Total		**5,678**	**-**	**5,678**	**-**	**(5,678)**	**Not included in Rate Base**
		2. Investments in Affiliated Co	1231044 Other Inv Apog Llc	250	-	250	-		
		2. Investments in Afflliated Co Total		**250**	**-**	**250**	**-**	**(250)**	**Not included in Rate Base**
		3. Other Investments	1240043 Other Inv Nustart	-	-	-	-		
			1240044 Other Inv Apog Llc	-	-	-	-		
			1280015 Other Special Funds-trust Loan	-	-	-	-		
			1280205 Other Special Funds-trust Cash	2,387,898	-	2,387,898	-		
			1280206 Other Special Funds-trust-csv	184,760,615	-	184,760,615	-		
		3. Other Investments Total		**187,148,514**	**-**	**187,148,514**	**-**	**(187,148,514)**	**Not included in Rate Base**
	2. Other Property and Investment Total			187,154,442	-	187,154,442	-		
	3. Current Assets	1. Cash Temp Inv & Spec Deposits	1310000 Cash	(26,275,471,043)	(7,193,525)	(26,282,664,568)	-		

SOUTH CAROLINA ELECTRIC & GAS
OFFICE OF REGULATORY STAFF AUDIT INFORMATION REQUEST
DOCKET 2017-207-E, 2017-305-E, 2017-370-E

Balance Sheet Reconciliation to Exhibit 14,15,16,17

RESPONSE NO. 1-24

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			1310001 Cash - Bank Of America	61,848,338	-	61,848,338	-		
			1310005 Cash - Chase Sce&g	-	-	-	-		
			1310100 Csh Trnfr Btwn Sc & Eg Units	(3,294,664,629)	(1,716,364)	(3,296,380,992)	-		
			1310200 Csh Trnfr Btwn Sh & Eg Units	5,218,603	2,518,205	7,736,808	-		
			1310300 Csh Trnfr Btwn Eg & Psnc Units	974,157	-	974,157	-		
			1310800 Csh Trnfr Btwn Svci & Sceg	5,619	-	5,619	-		
			1310901 Csh Trnfr Btwn Eg & Gen Eag	661,996,492	-	661,996,492	-		
			1310902 Csh Trnfr Btwn Eg & Re Eag	24,832,085,919	-	24,832,085,919	-		
			1310904 Csh Trnfr Btwn Eg & In Eag	3,387,880,403	-	3,387,880,403	-		
			1310905 Csh Trnfr Btwn Gen And Re Eag	108,391	-	108,391	-		
			1310906 Csh Trnfr Btwn Gen & Gas Eag	(1,011,660,912)	-	(1,011,660,912)	-		
			1310908 Csh Trnfr Btwn Re And Gas Eag	108,370,085	-	108,370,085	-		
			1310909 Csh Trnfr Btwn Re And In Eag	(939,930)	-	(939,930)	-		
			1310910 Csh Trnfr Btwn Gas And In Eag	7,071,567	-	7,071,567	-		
			1310920 Csh Trnfr Betwn Semic And Eg	(11,527)	-	(11,527)	-		
			1310930 Csh Trnfr Betwn Sega And Eg	(38,813)	-	(38,813)	-		
			1310940 Csh Trnfr Betwn Cgt And Eg	7,448,338	-	7,448,338	-		
			1310950 - Cash Transfer B/t Sci & Eg	362,833	-	362,833	-		
			1350000 Perm Working Funds	-	-	-	-		
			1350001 Temp Working Funds	-	-	-	-		
			1350002 Cashier Working Funds	43,925	-	43,925	-		
			1350003 Imprest Funds	-	-	-	-		
			1350009 Right Of Way Working Fund	(110,821)	-	(110,821)	-		
		1. Cash Temp Inv & Spec Deposits Total		**(1,509,483,005)**	**(6,391,683)**	**(1,515,874,688)**	**-**	**1,515,874,688**	**Not included in Rate Base**
		2. Accounts Receivable-Customers	1420200 Cust Ar Interchange & Wheeling	871,222	-	871,222	-		
			1420201 Wholesale Fuel Clause Under Co	(81,959)	-	(81,959)	-		
			1730000 Accrued Utility Revenues	94,769,395	-	94,769,395	-		
			1730001 Accr Util Rev Res-ewna	-	-	-	-		
			1730002 Accr Util Com - Ewna	-	-	-	-		
		2. Accounts Receivable-Customers Total		**95,558,658**	**-**	**95,558,658**	**-**	**(95,558,658)**	**Not included in Rate Base**
		3. Accounts Receivable-Other	1430001 Oth Ar Other	89,301,088	13,117	89,314,205	-		
			1430026 Other Ar Psa - Scfc Invoices	-	-	-	-		
			1430048 - Other Ar - Rg Billing	662	-	662	-		
			1430051 - A/r - Refunds From Ajg-s45	282,198	-	282,198	-		
			1430055 - Ar-ge Jasper $705k	26,591	-	26,591	-		
			1430111 Other Ar Chas Garage	710,558	-	710,558	-		
			1430200 Oth Ar Psa O And M	9,253,230	-	9,253,230	-		
			1430201 Oth Ar Psa Cap Wo16xxxx	3,087,709	-	3,087,709	-		
			1430203 Oth Ar Psa Vcs Stores Exp	(13,633)	-	(13,633)	-		
			1430204 Oth Ar Psa Vcs Inventory	97,186	-	97,186	-		
			1430205 Oth Ar Psa Nnd-vcs Units 2and3	50,123,211	-	50,123,211	-		
			1430207 Oth Ar Psa Retire Wk In Prgrss	320,912	-	320,912	-		
			1430600 Oth Ar Cable Owip Billings	105,565	-	105,565	-		
		3. Accounts Receivable-Other Total		**153,295,277**	**13,117**	**153,308,394**	**-**	**(153,308,394)**	**Not included in Rate Base**
		4. Accts Receivable Affiliated Co	1465051 Ar Affil Co-canadys Ref Coal	7,434,002	-	7,434,002	-		
		4. Accts Receivable Affiliated Co Total		**7,434,002**	**-**	**7,434,002**	**-**	**(7,434,002)**	**Not included in Rate Base**
		5. Inventories-Fuel	1510000 Fuel Stock Coal	-	19,958,385	19,958,385	-		
			1510100 Fuel Stock No2 Fuel Oil	19,373,732	-	19,373,732	-		
		5. Inventories-Fuel Total		**19,373,732**	**19,958,385**	**39,332,117**	**43,119,770**	**3,787,653**	**Included in Materials & Supplies in Exhibits 14,15,16,17 using a 12 month average balance**
		6a. Inventories-Emission Allow	1581000 Nox Allow Cair Allow Inv Cp	-	-	-	-		
			1581002 So2 Arp Allow Inv Cp	-	635,037	635,037	638,559		
		6a. Inventories-Emission Allow Total		**-**	**635,037**	**635,037**	**638,559**	**3,522**	**Allowances are included in Materials & Supplies in Exhibit 14,15,16,17 using a 12 month average**
		7. Inventories-Materls/Supplies	1540003 Plnt Matls And Oper Sup Vcs	45,173,091	-	45,173,091			
			1540400 M And S Inventory	89,593,111	-	89,593,111			
			1630000 Stores Exp	(3,568)	-	(3,568)			
		7. Inventories-Materls/Supplies Total		**134,762,634**	**-**	**134,762,634**	**135,154,798**	**392,164**	**Difference is related to Fleet. The Fleet business unit is not reflected on the Electric B/S. It is reflected on the SCE&G B/S**
		8. Prepayments	1650000 Prepayments - Misc	4,193,958	26,250	4,220,208	-		
			1650001 Prepay Fuel Interest	-	125,674	125,674	-		
			1650005 Title V Air Ems Fee	299,062	-	299,062	-		
			1650007 Prepayments- Leases	319,727	-	319,727	-		
			1650008 Prepaid Acct For Hydro Usgs	6,504	-	6,504	-		
			1650010 Prepay Hydro Water Sampler	277,020	-	277,020	-		
			1650018 Prepaid-software Agreement	-	-	-	-		

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			1650050 - Prepay-op Support Agrmts	79,645	-	79,645	-		
			1650225 Pike Anon Environmental Insura	-	-	-	-		
			1650434 Prepay - Commitment Fees		547,301	547,301	-		
		8. Prepayments Total		**5,175,916**	**699,225**	**5,875,141**	**84,883,295**	**79,008,154**	**Included in Working Capital Calculation. Many prepayments are included on the SCE&G B/S in total and therefore a calculation is done to determine the electric portion**
	3. Current Assets Total			(1,093,882,785)	14,914,079	(1,078,968,706)			
	4. Deferred Debits	1. Accum Deferred Income Tax	1900001 Adit Fed Nuc Fuel Amort	-	2,020,500	2,020,500			
			1900002 Adit St Nuc Fuel Amort	-	303,900	303,900			
			1900012 Adit St Elec Itc Fasb 109	(2,441,400)	-	(2,441,400)			
			1900013 Adit St Gas Itc Fasb 109	3,000	-	3,000			
			1900023 Adit Fed Elec Erip	(3,083,000)	-	(3,083,000)			
			1900027 Adit St Elec Erip	(463,500)	-	(463,500)			
			1900031 Adit Fed Elec Bonus Plan	26,900	-	26,900			
			1900037 Adit Fed Elec Epa Cleanup	(21,200)	-	(21,200)			
			1900041 Adit St Elec Epa Cleanup	(3,200)	-	(3,200)			
			1900045 Adit Fed Nuc Refuel	865,000	-	865,000			
			1900046 Adit St Nuc Refuel	130,200	-	130,200			
			1900047 Adit Fed Nuc Decom	31,145,892	-	31,145,892			
			1900048 Adit Fed Nuc Decom Oth Inc	37,239,815	-	37,239,815			
			1900049 Adit St Nuclear Decom	4,727,083	-	4,727,083			
			1900050 Adit St Nuc Decom Oth Inc	5,556,482	-	5,556,482			
			1900051 Adit Fed Otarre Basis	-	-	-			
			1900052 Adit St Otarre Basis	-	-	-			
			1900061 Adit Fed Elec Unbill Rev	-	-	-			
			1900063 Adit St Elec Unbill Rev	-	-	-			
			1900065 - Adit Elec Fed Closed Non-hedge	(41,462,400)	-	(41,462,400)			
			1900066 - Adit Elec St Closed Non-hedges	(6,235,000)	-	(6,235,000)			
			1900067 Adit Fed Elec Uncoll Accts	(441,200)	-	(441,200)			
			1900069 Adit St Elec Uncoll Accts	(66,400)	-	(66,400)			
			1900071 Adit Fed Elec Inj And Dam	1,340,400	-	1,340,400			
			1900074 Adit St Elec Inj And Dam	201,400	-	201,400			
			1900077 Adit Fed Elec Opeb	7,475,000	-	7,475,000			
			1900080 Adit St Elec Opeb	1,237,800	-	1,237,800			
			1900103 Adit Fed Elec St Inv Tax Crdts	-	-	-			
			1900104 Adit Fed Gas St Inv Tax Crdts	-	-	-			
			1900105 Adit Fed Elec Storm Dmg Accrls	(22,696,700)	-	(22,696,700)			
			1900106 Adit St Elec Storm Dmg Accrls	(3,413,100)	-	(3,413,100)			
			1900137 Adit Fed Elec Ltd	(2,612,300)	-	(2,612,300)			
			1900139 Adit St Elec Ltd	(392,900)	-	(392,900)			
			1900143 Adit Fed Elec Accrued Vacation	269,300	-	269,300			
			1900146 Adit St Elec Accrued Vacation	40,500	-	40,500			
			1900159 Adit Fed Nonoper Ferc Reserve	-	-	-			
			1900160 Adit St Nonoper Ferc Reserve	-	-	-			
			1900161 Adit Fed - Directors Endowment	96,200	-	96,200			
			1900162 Adit St - Directors Endowment	14,500	-	14,500			
			1900163 Adit St Elec Major Maint	(576,000)	-	(576,000)			
			1900165 Adit Fed Elec Major Maint	(3,829,700)	-	(3,829,700)			
			1900167 Adit St Elec Unearned Rev	(5,600)	-	(5,600)			
			1900169 Adit Fed Elec Unearned Revenue	(37,800)	-	(37,800)			
			1900179 Adit Fed St Tax Deduct Eiz	-	-	-			
			1900180 Adit Fed St Tax Ded Eiz-gas	-	-	-			
			1900197 - Fed Non Oper Serp Interco	277,700	-	277,700			
			1900198 - St Non Oper Serp Interco	41,800	-	41,800			
			1900199 Adit Fed Amt Cr Carryforward	-	-	-			
			1900267 - Adit Fed Elec Long Term Pledge	(111,200)	-	(111,200)			
			1900269 - Adit St Elec Long Term Pledges	(16,700)	-	(16,700)			
			1900272 Adit Fed Pal Ctnr Litigation	-	-	-			
			1900273 Adit St Pal Ctnr Litigation	-	-	-			
			1900274 Adit Fed Reg Asset Enviromenta	(114,300)	-	(114,300)			
			1900275 Adit St Reg Wat Scrubber	-	-	-			
			1900276 Adit Fed Reg Wat Scrubber	-	-	-			
			1900277 Adit St Reg Asset Enviromental	(17,400)	-	(17,400)			
			1900301 St Elec Opeb Fas 158	(82,400)	-	(82,400)			
			1900306 Fed Elec Opeb Fas 158	(548,200)	-	(548,200)			
			1900408 - Adit Fed Toshiba Settlement	364,164,100	-	364,164,100			

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			1900409 - Adit St Toshiba Settlement	54,761,500	-	54,761,500			
			1900410 - Adit Fed Impairment Charge	68,185,800	-	68,185,800			
			1900411 - Adit St Impairment Charge	10,253,500	-	10,253,500			
		1. Accum Deferred Income Tax Total		**499,382,272**	**2,324,400**	**501,706,672**	**2,655,000**	**(499,051,672)**	**ADIT is booked in total for SCE&G. A calculation is done to determine the amount applicable to electric**
		2. Clearing Accounts	1840250 Clr Storeroom Sales	4,356	-	4,356	-		
			1840641 - Indir Payroll Holiday	6,816,926	-	6,816,926	-		
			1840644 - Indir Payroll Jury Duty	67,434	-	67,434	-		
			1840645 - Indir Payroll Funeral	368,580	-	368,580	-		
			1840646 - Indir Payroll Paid Time Off	13,444,540	-	13,444,540	-		
			1840649 - Clear Indirect Payroll	(20,697,322)	-	(20,697,322)	-		
		2. Clearing Accounts Total		**4,514**	**-**	**4,514**	**-**	**(4,514)**	**Not included in Rate Base**
		3. Misc Deferred Debits	1750000 Derivative Instruments - Ncemc	-	-	-	-		
			1860006 - Def Dr Inv Wo Prop Acct Dist	8,125	-	8,125	-		
			1860007 - Def Dr Blnkt Po Wo Prop Dist	9,211	-	9,211	-		
			1860010 Misc Deferred Debits - Misc	146,573	-	146,573	-		
			1860022 Def Dr Other Work In Prog	28,730,670	-	28,730,670	-		
			1860023 Def Dr Telephone Pole Rent	1,647,658	-	1,647,658	-		
			1860053 Def Debit-chas Garage L-t Rec	-	-	-	-		
			1860067 Chas Garage Accrued Interest	1,590	-	1,590	-		
			1860069 - Def Debit Cble Pole Attach Ren	1,663,733	-	1,663,733	-		
			1860072 Def Dr - Canadys W O Issuance	-	-	-	-		
			1860073 Def Dr - Mcmeekin W O Issuance	-	-	-	-		
			1860081 Deferred Dr-jasper Ge Csa	681,312	-	681,312	-		
			1860085 Def Dr Nu Inventory Wo	(68,593)	-	(68,593)	-		
			1860096 Deferred Debit - Urquhart Ge C	303,414	-	303,414	-		
			1860134 - Def Dr 5yr Commitment Fees		1,185,820	1,185,820	-		
			1860149 Sceg Workers Comp Reserve Def	165,167		165,167	-		
			1860200 - Def Dr - Vcs Isfsi Maint	413,243	-	413,243	-		
			1860201 - Def Dr - Vcs Inv Obs	752,802	-	752,802	-		
			1860202 - Def Dr-vcs Wo Issuance	3,773,027	-	3,773,027	-		
			1860241 - Interconnect Studies Deposit	82,500	-	82,500	-		
			1860306 Def Dr Ar Psa Opeb	11,281,862	-	11,281,862	-		
			1860405 - Ar Int Inc Amended Rtn	2,147,023	-	2,147,023	-		
			1860505 - Def Debit-ge Jasper $705k	15,369	-	15,369	-		
			1860632 Ar Opeb Psa	4,074,233	-	4,074,233	-		
		3. Misc Deferred Debits Total		**55,828,918**	**1,185,820**	**57,014,738**	**-**	**(57,014,738)**	**Not included in Rate Base**
		4. Other Regulatory Assets	1822100 Unrecovered Plant Parr	498,661	-	498,661	-		
			1822101 Unrecov Plnt Contra Parr	(498,661)	-	(498,661)	-		
			1822102 Unrecov Plant Hagood	876,914	-	876,914	-		
			1822103 Unrecov Plnt Contra Hagood	(876,914)	-	(876,914)	-		
			1822104 Unrecov Plnt Defective Stm Gen	10,476,165	-	10,476,165	-		
			1822105 Unrcvrd Plt Dfctv Stm Gen Cont	(10,476,165)	-	(10,476,165)	-		
			1822106 - Unrecovered Plant - Urq Unit 3	557,755	-	557,755	-		
			1822107 - Unrecovered Plant - Mcmeekin	1,427,729	-	1,427,729	-		
			1822108 - Unrecovered Plant - Canadys 2	96,230,804	-	96,230,804	59,422,522	(36,808,283)	Tax effected balance is included in Rate Base
			1822200 Demolition - Parr Steam Plant	961,933	-	961,933	-		
			1822201 Demolitn-contra-parr Steam Plt	(961,933)	-	(961,933)	-		
			1822202 Demolitn-hagood Steam Plant	964,004	-	964,004	-		
			1822203 Demolitn-contra-hagood Stm Plt	(964,004)	-	(964,004)	-		
			1822208 - Unrecovered Plant - Can Unit 1	12,125,813	-	12,125,813	7,487,689	(4,638,123)	Tax effected balance is included in Rate Base
			1823004 Reg Asst Fuel Claus Undrcllctn	-	-	-			
			1823016 City Of Charleston - Franchise	32,012,572	-	32,012,572			
			1823017 Charleston - Franchise-contra	(27,356,355)	-	(27,356,355)			
			1823018 City Of Columbia - Franchise	50,841,005	-	50,841,005			
			1823019 Columbia - Franchise - Contra	(41,148,154)	-	(41,148,154)			
			1823026 Reg Asset Major Maint Accrual	13,173,377	-	13,173,377			
			1823028 Reg Asset Elec Fuel - Unbilled	-	-	-			
			1823041 Reg Asset Reagent Under Colect	-	-	-			
			1823046 Carolina Transfmr Superfd Site	-	-	-			
			1823048 2010 $25mil Elec Wthr Adj	-	-	-			
			1823051 Interest Income Mjm Psc Accrl	954,841	-	954,841			
			1823052 Reg Asset - Environmental Psi	264,602	-	264,602			
			1823055 Reg Asset Def Vcs Up-flow Mod	4,552,289	-	4,552,289			
			1823056 Reg Asst Recover Capacity Purc	826,333	-	826,333			
			1823057 Incremental Rate Case Expenses	-	-	-			
			1823063 Reg Asset So2 Emission Allowan	-	-	-			

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			1823064 Reg Asset-defer Capacity Purch	-	-	-			
			1823065 - Reg Asset-fukushima-vcs	4,211,659	-	4,211,659			
			1823066 - Reg Asset - Defer Capacity Pur	2,134,511	-	2,134,511			
			1823069 - Reg Asset-def Cap-2014-2016-so	2,624,177	-	2,624,177			
			1823070 - Reg Asset-def Cap-2014-19 Colu	20,698,982	-	20,698,982			
			1823072 - Reg Asset Nnd Carrying Costs	45,762,447	-	45,762,447			
			1823073 - Reg Asset - Cip5	11,003,551	-	11,003,551			
			1823075 - Reg Asset-cyber Security Compl	3,084,297	-	3,084,297			
			1823085 - Reg Asset-cyber Secur Depr Car	912,118	-	912,118			
			1823095 - Reg Asset Nnd 41/199 (pilot)	18,730,200	-	18,730,200			
			1823096 - Reg Asset Nnd Acct Fees/intere	8,958,262	-	8,958,262			
			1823105 Reg Asset - Decom Aro	(10,697,724)	-	(10,697,724)			
			1823106 Def Aro Acretion And Arc Depr	321,685,989	-	321,685,989			
			1823107 Def Econ Grant - Dixie Narco	200,000	-	200,000			
			1823108 Def Econ Grant - Michelin	358,333	-	358,333			
			1823109 Def Econ Grant-bf Phase 1	425,000	-	425,000			
			1823110 Def Econ Grant-bf Phase 2	425,000	-	425,000			
			1823111 Def Econ Grant-bf Phase 3	2,096,667	-	2,096,667			
			1823112 R & D Grant - Clemson	3,025,000	-	3,025,000			
			1823113 - Def Econ Grant - Michelin 2	236,264	-	236,264			
			1823114 - Def Econ Grant - Nexans	175,000	-	175,000			
			1823115 - Def Econ Grant - Koyo Corp	168,750	-	168,750			
			1823116 - Def Econ Grant - Boeing/chas C	4,527,778	-	4,527,778			
			1823117 - Def Econ Grant - Mercedes/chas	1,888,889	-	1,888,889			
			1823118 - Def Econ Grant - Fairfield Meg	2,204,558	-	2,204,558			
			1823120 - Def Econ Grant-kronotex	977,778	-	977,778			
			1823200 Reg Asset Dem Side Mgt Costs	1,220,327	-	1,220,327			
			1823205 - Deferred Storm Damage Costs	22,200,018	-	22,200,018			
			1823255 - Res Water Heaters	2,788,787	-	2,788,787			
			1823256 - Res Appliance Recycling	1,310,632	-	1,310,632			
			1823259 - Res Limited Income	2,502,555	-	2,502,555			
			1823260 Dsm Admin	5,411,269	-	5,411,269			
			1823261 Res Benchmarking	3,363,256	-	3,363,256			
			1823262 Res In-home Display	1,315,466	-	1,315,466			
			1823263 Res Energy Check Up	4,062,626	-	4,062,626			
			1823264 Res Estar Light And Appliance	15,509,086	-	15,509,086			
			1823265 Res New Hvac Water Heater	11,922,237	-	11,922,237			
			1823266 Res Existing Hvac - Tune-up	1,956,211	-	1,956,211			
			1823267 Res Energy Star New Homes	1,557,504	-	1,557,504			
			1823268 Res Home Perf Audit	3,613,364	-	3,613,364			
			1823271 Com And Ind Prescriptive	30,740,864	-	30,740,864			
			1823272 Com And Ind Custom	4,476,934	-	4,476,934			
			1823273 Dsm C And I Special Project	4,146,321	-	4,146,321			
			1823280 Res Dsm Accum Amort	(29,222,351)	-	(29,222,351)			
			1823281 Com Ind Dsm Accum Amort	(18,059,938)	-	(18,059,938)			
			1823282 Res Dsm Carrying Costs	9,873,764	-	9,873,764			
			1823283 Com Ind Dsm Carrying Costs	5,907,439	-	5,907,439			
			1823385 - Der/net - O&m Incremental	3,373,752	-	3,373,752			
			1823391 - Der Avoided Costs	(3,521,688)	-	(3,521,688)			
			1823392 - Der Capital - Incremental	(370,230)	-	(370,230)			
			1823398 - Der Incremental Nem Costs Def	(1,645,627)	-	(1,645,627)			
			1823414 - Reg Asset - Elec Fas 87 Deferr	53,210,719	-	53,210,719	32,857,619	(20,353,100)	Tax effected balance is included in Rate Base
			1823601 Reg Asset-poll Cntrl-wms Scrbr	7,731,607	-	7,731,607			
			1823602 Reg Asset-poll Cntrl-wat Scrbr	24,359,501	-	24,359,501	15,041,992	(9,317,509)	Tax effected balance is included in Rate Base
		4. Other Regulatory Assets Total		**760,014,499**	**-**	**760,014,499**	**114,809,821**	**(645,204,677)**	**Canadys retirement, Wateree scrubber deferral and pension deferral included in Rate base at tax effected amount**
		5. Prelim Suvy & Investigation	1830020 Psi Prelim Engr Vcs	-	-	-	-		
			1830175 Landfill Compl - Waste Reclass	-	-	-	-		
			1830178 Wateree - So3 Injection System	-	-	-	-		
			1830180 - Fish Entrainment Studies	116,852	-	116,852	-		
			1830186 - Psi Vcs1 Switchyard Add Capaci	2,137	-	2,137	-		
			1830187 - Meeting St Replacement Sub Sit	3,496	-	3,496	-		
			1830523 Psi - Lidar Surveys	-	-	-	-		
			1830524 - Calhoun/bull St Substation	65,543	-	65,543	-		
			1832005 - Fossil Hydro Study	552,286	-	552,286	-		
		5. Prelim Suvy & Investigation Total		**740,315**	**-**	**740,315**	**-**	**(740,315)**	**Not included in Rate Base**
	4. Deferred Debits Total			1,315,970,517	3,510,220	1,319,480,738			

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
Total Assets and Other Debits Total				**11,213,821,431**	**267,487,287**	**11,481,308,718**	**11,665,953,147**	**184,644,429**	
Total Liabilities/Other Credt	1. Current Liabilities	1. Accounts Payable	2320000 Apay	-	-	-	-		
			2320001 Apay Fuel Liabilities	61,395	11,082,930	11,144,325	-		
			2320003 Apay Manual Accrual	15,259,346	-	15,259,346	-		
			2320013 - Ap Manual Accruals - Inc Stmnt	10,931,176	-	10,931,176	-		
			2320023 - Ap Manual Accruals-bal Sheet	44,800,488	-	44,800,488	-		
			2320103 Apay Stvn Ck Hdwtr Bene Chg	57,789	-	57,789	-		
			2320106 Apay Disp Costs Nuc Two 3rds	-	-	-	-		
			2320107 Apay Disp Costs Psa	-	-	-	-		
			2320112 Apay Ferc Annual Bill Chg	-	-	-	-		
			2320118 Apay Accr Rcpts Liab	816,447	-	816,447	-		
			2320119 Apay Nonstock Rcpts Acrl Psft	2,040,563	-	2,040,563	-		
			2320121 Apay Bulk Pwr And Transmission	10,321,805	-	10,321,805	-		
			2320200 Apay Pace	-	-	-	-		
		1. Accounts Payable Total		**84,289,009**	**11,082,930**	**95,371,939**	**-**	**(95,371,939)**	**Not included in Rate Base**
		2. Accounts Payable Assoc Co	2340010 Apay Assoc Co Scfc	-	-	-	-		
			2340014 Apay Assoc Co Genco	-	-	-	-		
			2340101 Apay Assoc Co Genco Billing	8,019,853	-	8,019,853	-		
			2341029 Inter Co Payable Sc Apay	19,906,096	-	19,906,096	-		
		2. Accounts Payable Assoc Co Total		**27,925,949**	**-**	**27,925,949**	**-**	**(27,925,949)**	**Not included in Rate Base**
		3. Accounts Payable-Affiliated Co	2345051 Ap Affiliate Co-canadays Refin	7,479,393	-	7,479,393	-		
		3. Accounts Payable-Affiliated Co Total		**7,479,393**	**-**	**7,479,393**	**-**	**(7,479,393)**	**Not included in Rate Base**
		4. Interest Accrued Other	2370201 Int Accr Commit Fee Nuc	-	2,163	2,163	-		
			2370202 - Int Acr Cm Ppr Comm Fee Fosful	-	267	267	-		
		4. Interest Accrued Other Total		**-**	**2,431**	**2,431**	**-**	**(2,431)**	**Not included in Rate Base**
		5. Misc Current Liabilities	2420000 Misc Cur And Accr Liab	6,718,225	-	6,718,225	-		
			2420004 Misc Cur & Accr Liab Retainage	-	-	-	-		
			2420005 Ferc Annual Hydro Bill	214,689	-	214,689	-		
			2420007 Misc Acc Liab Nl Shls	-	-	-	-		
			2420013 Msc Cur&acr Nucl Radwaste Liab	1,389,196	-	1,389,196	-		
			2420033 Misc Accr Fin 48 Interest	-	-	-	-		
			2420202 - Accrued Benefits	185,899	-	185,899	-		
			2420300 Msc Cur & Accr Liab Accr Pyrll	7,010,180	-	7,010,180	-		
		5. Misc Current Liabilities Total		**15,518,189**	**-**	**15,518,189**	**-**	**(15,518,189)**	**Not included in Rate Base**
		6. Notes Payable	2310000 Notes Payable	-	255,336,000	255,336,000	-		
		6. Notes Payable Total		**-**	**255,336,000**	**255,336,000**	**-**	**(255,336,000)**	**Not included in Rate Base**
		7. Tax Collections Payable	2410111 - Tax Col Pay Sc Sales Tax Other	344	-	344	-		
			2410112 Tax Col Pay Sc Use Tax	376,339	-	376,339	-		
			2410200 - Tax Col Pay Lost Collctd Other	246	-	246	-		
			2410201 Tax Col Pay Lost Coll Pay Use	26,059	-	26,059	-		
			2410210 - Tax Col Pay Lost Oth Trans	123	-	123	-		
			2410211 - Tax Col Pay Lost Oth School	246	-	246	-		
			2410220 Tax Col Pay Lost Use Transp	22,796	-	22,796	-		
			2410221 Tax Col Pay Lost Use School	36,978	-	36,978	-		
			2410222 Tax Col Pay Lost Use Capitl	6,438	-	6,438	-		
		7. Tax Collections Payable Total		**469,569**	**-**	**469,569**	**-**	**(469,569)**	**Not included in Rate Base**
		8. Taxes Accrued Federal Income	2360002 Taxes Accr Current Fed Inc	(51,599,681)	(1,619,000)	(53,218,681)			
			2360300 Tax Accr Fed Sbu Estimate	101,687,376		101,687,376			
		8. Taxes Accrued Federal Income Total		**50,087,695**	**(1,619,000)**	**48,468,695**	**(118,015,305)**	**(166,484,000)**	**Included in Working Capital Calculation. Amount reflected includes both federal and state 13 month averages**
		9. Taxes Accrued State Income	2360003 Taxes Accr State Inc Tax	(51,284,832)	(11,300)	(51,296,132)			
			2360301 Tax Accr State Sbu Estimate	14,358,032	-	14,358,032			
		9. Taxes Accrued State Income Total		**(36,926,799)**	**(11,300)**	**(36,938,099)**	**-**	**36,938,099**	**See above**
	1. Current Liabilities Total			148,843,004	264,791,061	413,634,064	(118,015,305)		
	2. Deferred Credits	1. Accum Def Inc Taxes-Liability	2820001 Adit Fed Elec Liberal Depr	40,082,080	-	40,082,080			
			2820004 Adit Fed Btl Depr	6,499,100	-	6,499,100			
			2820005 Adit St Elec Liberal Depr	8,270,200	-	8,270,200			
			2820008 Adit St Btl Depr	971,400	-	971,400			
			2820009 Adit Fed Parr & Hagood Demltn	-	-	-			
			2820011 Adit Fed Elec Intangibles	(11,310,100)	-	(11,310,100)			
			2820014 Adit St Elec Intangibles	(1,669,800)	-	(1,669,800)			

SOUTH CAROLINA ELECTRIC & GAS
OFFICE OF REGULATORY STAFF AUDIT INFORMATION REQUEST
DOCKET 2017-207-E, 2017-305-E, 2017-370-E

Balance Sheet Reconciliation to Exhibit 14,15,16,17

RESPONSE NO. 1-24

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			2820029 Adit Fed Elec Basis Dif	64,555,616	-	64,555,616			
			2820030 - Adit Fed New Nucl Int Dif	34,368,800	-	34,368,800			
			2820033 Adit St Elec Basis Dif	8,394,000	-	8,394,000			
			2820034 - Adit St New Nucl Int Dif	5,171,200	-	5,171,200			
			2820038 Adit Fed Int Emis Allowances	(2,013,000)	-	(2,013,000)			
			2820039 Adit St Emis Allowances	(302,600)	-	(302,600)			
			2820044 Adit State Elec Removal Cost	-	-	-			
			2820046 Adit Fed Elec Removal Cost	-	-	-			
			2820065 Adit Fed Fin 48	(29,639,000)	-	(29,639,000)			
			2820066 Adit St Fin 48	(4,570,200)	-	(4,570,200)			
			2820068 Adit Fed Repairs Project	-	-	-			
			2820069 Adit State Repairs Project	-	-	-			
			2820070 Adit Fed Reg Pollution Control	2,215,300	-	2,215,300			
			2820071 Adit St Reg Pollution Control	333,300	-	333,300			
			2820072 Adit Fed Wateree Scrubber	(477,800)	-	(477,800)			
			2820073 Adit St Wateree Scrubber	(71,800)	-	(71,800)			
			2820078 - Adit Fed Net Elec Nucl Arc	2,841,279	-	2,841,279			
			2820079 - Adit St Net Elec Nucl Arc	427,260	-	427,260			
			2820082 Adit Fed No2 Emission Allowanc	(15,200)	-	(15,200)			
			2820083 Adit St No2 Emission Allowance	(2,300)	-	(2,300)			
			2820084 - Adit Fed Nnd Basis Diff (orig	8,312,500	-	8,312,500			
			2820085 - Adit St Nnd Basis Diff (orig C	1,250,000	-	1,250,000			
			2820092 Powertax Adj-state	-	-	-			
			2820100 Adit St Elec Lake Murray Dam	-	-	-			
			2820101 - Adit Fed Nnd Basis Diff (pilot	470,309,000	-	470,309,000			
			2820102 - Adit St Nnd Basis Diff (pilot)	70,720,200	-	70,720,200			
			2820103 - Adit Fed Fin 48 (pilot)	(281,303,700)	-	(281,303,700)			
			2820104 - Adit St Fin 48 (pilot)	(42,301,300)	-	(42,301,300)			
			2820110 Adit Fed Elec Lake Murray Dam	-	-	-			
			2820111 Adit St Dam Basis Dif	-	-	-			
			2820112 Adit Fed Dam Basis Dif	-	-	-			
			2820142 Adit St Dam Research	-	-	-			
			2820143 Adit Fed Dam Research Project	-	-	-			
			2820144 Adit Fed Elec Research Project	-	-	-			
			2820145 Adit St Elec Research Project	-	-	-			
			2820146 Adit Fed Elec Res And Exp	(7,617,100)	-	(7,617,100)			
			2820148 Adit State Elec Res And Exp	(1,115,800)	-	(1,115,800)			
			2830001 Adit Fed Wesths Litigation	-	-	-			
			2830002 Adit St Wesths Litigation	-	-	-			
			2830017 Adit Fed Elec Fuel	(1,247,800)	-	(1,247,800)			
			2830019 Adit St Elec Fuel	(762,700)	-	(762,700)			
			2830021 Adit Fed Elec Res And Exp	-	-	-			
			2830024 Adit St Elec Res And Exp	-	-	-			
			2830029 Adit Fed Elec Dem Side Mgt	18,684,100	-	18,684,100			
			2830030 Adit St Elec Dem Side Mgt	2,809,700	-	2,809,700			
			2830031 Adit Fed Elec Ls Reacq Debt	(3,761,100)	-	(3,761,100)			
			2830033 Adit St Elec Ls Reacq Debt	(565,600)	-	(565,600)			
			2830039 Adit Fed Elec Pension Exp	(5,391,300)	-	(5,391,300)			
			2830042 Adit Fed Nonop Pension Exp	2,888,600	-	2,888,600			
			2830043 Adit St Elec Pension Exp	(810,800)	-	(810,800)			
			2830046 Adit St Nonop Pension Exp	434,500	-	434,500			
			2830053 Adit Fed Non Oper Knd Exchng	-	-	-			
			2830054 Adit St Non Oper Kind Exchngs	-	-	-			
			2830056 Adit State Pal Ctr Elec	-	-	-			
			2830059 Adit Fed Pal Ctr Elec	-	-	-			
			2830082 Adit Fed Elec Gridsouth	-	-	-			
			2830083 Adit State Elec Gridsouth	-	-	-			
			2830084 Adit Fed Elec Prepayments	11,336,200	-	11,336,200			
			2830086 Adit State Elec Prepayments	1,704,800	-	1,704,800			
			2830099 - Adit Fed Defer Capacity	5,169,500	-	5,169,500			
			2830118 Adit Fed Rec Cap Reg Asset	(225,800)	-	(225,800)			
			2830119 Adit St Rec Cap Reg Asset	(34,000)	-	(34,000)			
			2830129 - Adit St Defer Capacity	777,800	-	777,800			
			2830130 - Adit Fed Fukishima Reg Asset	1,422,900	-	1,422,900			
			2830131 - Adit St Fukishima Reg Asset	213,900	-	213,900			
			2830136 - Adit St Unrecovered Plant- Can	6,261,000	-	6,261,000			
			2830137 - Adit Fed Unrecovered Plant- Ca	41,635,600	-	41,635,600			
			2830142 - Adit Fed Grants	1,882,800	-	1,882,800			
			2830143 - Adit St Grants	283,200	-	283,200			
			2830145 - Adit Fed Mcmeekin	342,100	-	342,100			

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			2830148 - Adit St Mcmeekin	51,500	-	51,500			
			2830153 - Adit Fed Btl Fin 48 Int/exp	306,000	-	306,000			
			2830154 - Adit St Btl Fin 48 Int Inc/exp	45,900	-	45,900			
			2830157 - Adit Fed Elec Pilot Fin48 Int	(2,411,800)	-	(2,411,800)			
			2830158 - Adit St Elec Pilot Fin48 Int E	(362,700)	-	(362,700)			
			2830166 - Adit Fed Pilot Fasb 109	6,227,800	-	6,227,800			
			2830167 - Adit St Pilot Fasb 109	936,500	-	936,500			
			2830168 - Adit Fed Pilot Interest/prof F	2,975,900	-	2,975,900			
			2830169 - Adit St Pilot Interest/prof Fe	447,600	-	447,600			
			2830173 Adit St Vcs Cost Under Rateor	51,900	-	51,900			
			2830174 Adit Fed Vcs Cost Under Rateor	345,200	-	345,200			
			2830179 - Adit Fed Nnd Carrying Cost-reg	15,215,900	-	15,215,900			
			2830184 - Adit St Nnd Carrying Cost-reg	2,288,400	-	2,288,400			
			2830187 - Adit Fed Elec Jad Contract Ter	(399,000)	-	(399,000)			
			2830188 - Adit St Elec Jad Contract Term	(60,000)	-	(60,000)			
			2830189 - Adit Fed Elec Cybersecurity	2,432,900	-	2,432,900			
			2830210 - Adit Fed Elec Net Metering	(350,200)	-	(350,200)			
			2830211 - Adit St Elec Net Metering	(52,600)	-	(52,600)			
			2830212 - Adit St Gas Pipeline Integrity	38,000	-	38,000			
			2830213 - Adit Fed Gas Pipeline Integrit	252,400	-	252,400			
			2830214 - Adit St Elec Cybersecurity	365,900	-	365,900			
			2830301 St Elec Opeb Reg Rec	(82,400)	-	(82,400)			
			2830306 Fed Elec Opeb Reg Rec	(548,200)	-	(548,200)			
		1. Accum Def Inc Taxes-Liability Total		**453,074,035**	**-**	**453,074,035**	**(1,170,963,900)**	**(1,624,037,935)**	**ADIT is booked in total for SCE&G. A calculation is done to determine the amount applicable to electric**
		2. Decommision Reserve	2300000 Asset Retirement Oblig - Vcs	205,671,299	-	205,671,299	-		
			2300002 Aro Layer 2	-	-	-	-		
		2. Decommision Reserve Total		**205,671,299**	**-**	**205,671,299**		**(205,671,299)**	**Not included in Rate Base**
		3. Other Asset Retirement Obligtn	2300001 Aro - Electric And Gas	285,142,036	-	285,142,036	-		
		3. Other Asset Retirement Obligtn Total		**285,142,036**	**-**	**285,142,036**	**-**	**(285,142,036)**	**Not included in Rate Base**
		4. Other Deferred Credits	2282000 Acc Pro Inj And Dam Claims	2,774,758	-	2,774,758			
			2282010 Acc Pro Inj And Dam Work Comp	2,458,974	-	2,458,974			
			2282017 Acc Pro Work Comp Nnd	3,135,800	-	3,135,800			
			2530018 Misc Deferred Credits - Misc	-	-	-			
			2530038 Chas Garage Pre-pymt	102,419	-	102,419			
			2530041 - Interconnect Studies Deposit	82,500	-	82,500			
			2530045 Unearned Rev - Street Lights	-	-	-			
			2530047 Oth Def Cr Nustart-psa	-	-	-			
			2530048 Oth Def Cr Apog Llc-psa	113	-	113			
			2530053 Santee River Basin Accord	959,384	-	959,384			
			2530065 City Of Columbia Nssf	5,854,308	-	5,854,308			
			2530070 Intercon Stdy Dep 3rd Pty	2,712,184	-	2,712,184			
			2530159 - Ap Fin 48 Int Exp	8,581,700	-	8,581,700			
			2530198 - Ingleside Future Ciac Obligati	1,559,702	-	1,559,702			
			2530199 - Cainhoy Future Ciac Obligation	15,764,543	-	15,764,543			
			2530200 - Def Cr Cbl Pole Attach Rentals	2,230,276	-	2,230,276			
			2530223 Def Cr Srs Substation Markup	1,733,107	-	1,733,107			
			2530224 Trans Payable-twn Of Blythewoo	-	-	-			
			2530911 Def Cr Burton Ins Proceeds	-	-	-			
		4. Other Deferred Credits Total		**47,949,768**	**-**	**47,949,768**	**(113,188,619)**	**(161,138,387)**	**Includes per books amounts for Injuries & Damages; FAS 106 Liability, and Net Environmental Liability as a reduction to Rate Base.**
		5. Other Regulatory Liabilities	2540000 - Reg Liab Fuel Clause Ovrcllctn	(15,174,996)	-	(15,174,996)			
			2540006 Reg Liab - Storm Damage	-	-	-			
			2540007 Reg Liab - In Storm Damage	-	-	-			
			2540008 Reg Liab - Ncemc Contract	-	-	-			
			2540011 Oth Reg Liab Nuclear Refueling	2,850,791	-	2,850,791	(1,760,363)	(4,611,154)	Exhibit 14,15,16,17 amount is Tax effected
			2540013 - Reg Liab Elec - Unbilled Fuel	18,179,011	-	18,179,011			
			2540041 - Reg Liab Reagent Over Collect	1,410,591	-	1,410,591			
			2540080 Equity Dsm Residential Carry C	2,531,108	-	2,531,108			
			2540081 Equity Dsm Com/ind Carry Costs	1,410,693	-	1,410,693			
			2540089 - Winnsboro Fuel Overcollected	62,850	-	62,850			
			2540090 - Orangeburg Fuel Over Collected	1,023,966	-	1,023,966			
			2540098 - Reg Liab - Enviromental Remedi	53,153	-	53,153			
			2540100 - Reg Liab So2 Arp	707	-	707			

Category	Sub Category	Sub Category 1	Account Description	ELEC	SCFC	Grand Total	Exhibit 14,15,16,17 Amt	Diff	Comments
			2540101 - Reg Liab S02 Csapr	322	-	322			
			2540121 St Adit Coaltch Op-wat	(111,600)	-	(111,600)			
			2540122 Fed Adit Coaltech-wat	(486,600)	-	(486,600)			
			2540123 Fed Syn Tax Cr-wat	(1,737,559)	-	(1,737,559)			
			2540124 St Adit Coaltch Op-cdy	(49,500)	-	(49,500)			
			2540125 Fed Adit Coaltech-cdy	(330,300)	-	(330,300)			
			2540126 Fed Syn Tax Cr-cdy	(1,090,141)	-	(1,090,141)			
			2540140 - Rg Liab-toshiba Settl Proceeds	1,095,230,291	-	1,095,230,291			
			2540150 Reg Liab Nox Ozone Cair	-	-	-			
			2540151 - Reg Liab Nox Ozone Csapr	657	-	657			
			2540160 Reg Liab Nox Annual Cair	-	-	-			
			2540161 - Reg Liab Nox Annual Csapr	377	-	377			
			2540162 - Elec Pension Rider Overrcvry	96,173	-	96,173			
			2540205 Reg Liab Itc State Electric	(2,441,400)	-	(2,441,400)			
			2540206 Reg Liab Itc State Gas	3,000	-	3,000			
		5. Other Regulatory Liabilities Total		**1,101,431,596**	**-**	**1,101,431,596**	**(1,760,363)**	**(1,103,191,959)**	
		6. Unrecognized Tax Benefits	2360015 - Taxes Accrd Fed Fin 48 (origin	29,197,000	-	29,197,000	-		
			2360016 - Taxes Accrd St Fin 48 (origina	4,570,200	-	4,570,200	-		
			2360018 - Taxes Accrd Fed Fin 48 (pilot)	289,179,500	-	289,179,500	-		
			2360019 - Taxes Accrd St Fin 48 (pilot)	84,721,300	-	84,721,300	-		
		6. Unrecognized Tax Benefits Total		**407,668,000**	**-**	**407,668,000**	**-**	**(407,668,000)**	**Not included in Rate Base**
	2. Deferred Credits Total			2,500,936,734	-	2,500,936,734			
	3. Total Capitalization	1. Long-Term Debt	2240206 State Infrastructure Bank Loan	-	-	-	-		
		1. Long-Term Debt Total		**-**	**-**	**-**	**-**	**-**	**Not included in Rate Base**
		2. Total Stockholders Investment	2010000 Com Stk Issued	-	1,000	1,000	-		
			2080000 Donations From Stockholders	-	2,695,226	2,695,226	-		
			2110000 Misc Paid In Cap Org Adv-sceg	3,066,016,900	-	3,066,016,900	-		
			2151000 App Ret Earn Amt Resv Fed Proj	83,909,569	-	83,909,569	-		
			2160000 Unapp Retained Earnings	5,244,504,054	-	5,244,504,054	-		
			2160001 Unap Ret Earn Pro-div Pref Stk	(82,234,637)	-	(82,234,637)	-		
			2169999 - Cur Mo Retd Earn	251,845,807	-	251,845,807	-		
		2. Total Stockholders Investment Total		**8,564,041,693**	**2,696,226**	**8,566,737,919**	**-**	**(8,566,737,919)**	**Not included in Rate Base**
	3. Total Capitalization Total			8,564,041,693	2,696,226	8,566,737,919	-	(8,566,737,919)	
Total Liabilities/Other Credt Total				**11,213,821,431**	**267,487,287**	**11,481,308,718**	**(1,403,928,187)**	**(12,885,236,905)**	

		10,262,024,959
Additional Working Capital Items in Exhibit 14,15,16,17	Working Cash (1/8 of O&M)	118,264,371
	Customer Deposits	(54,354,631)
	Adjustment for Rounding	1
	Rate Base per Exhibit 14,15,16,17	**10,325,934,700**

SOUTH CAROLINA ELECTRIC & GAS
OFFICE OF REGULATORY STAFF AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E, 2017-305-E, 2017-370-E

Income Statement Reconciliation

RESPONSE NO. 1-24

	Electric Amount
1 Revenues	
Electric Sales	
Commercial	
4420000 Commercial Sales Elec	840,680,830
4420090 Commercial Elec Unbilled	3,966,607
Commercial Total	844,647,437
Industrial	
4420001 Industrial Sales Elec	442,895,977
4420091 Industrial Elec Unbilled	500,467
Industrial Total	443,396,444
Other Public Authorities	
4450000 Oth Sales To Public Auth Elec	47,018,806
4450090 Opas Unbilled	190,130
Other Public Authorities Total	47,208,936
Over/Under Recovery Fuel-Retail	
4490000 Sale Rev Fuel Cls Ovr-undrcoll	58,331,634
Over/Under Recovery Fuel-Retail Total	58,331,634
Over/Under Recovery Fuel-Wholesale	
4470008 Other Sale For Resale Rev	1,164,547
Over/Under Recovery Fuel-Wholesale Total	1,164,547
Residential	
4400000 Residential Sales Elec	1,129,389,085
4400090 Residential Elec Unbilled	3,652,049
Residential Total	1,133,041,134
Sales For Resale-Interchange	
4470002 Sale For Resale-nmst-s-t	515,533
4470004 Sale For Resale- Transm-s-t	105,033
4470005 Sale For Resale-nmst-l-t	43,186,795
4470006 Sale For Resale- Transm-l-t	0
4470007 Sale For Resale Nmst Contra	(64)
Sales For Resale-Interchange Total	43,807,297
Sales For Resale-Municipal	
4470001 Mun Sale-resle Fulle Rqur Trff	1,189,595
Sales For Resale-Municipal Total	1,189,595
Street Lighting	
4440000 Pub Street And Hwy Lgt Elec	14,939,780
4440090 St Lights Unbilled	4,551
Street Lighting Total	14,944,331
Electric Sales Total	**2,587,731,354**
Other Operating Revenue	
Electric Facility Charge	
4540000 Rent Frm Elec Prop Facil Chrgs	11,206,150
4540004 Rent Elec Prop Lady St Semi	0
Electric Facility Charge Total	11,206,150
Misc Service Revenue	

RESPONSE NO. 1-24

	Electric Amount
4500000 Delinquent Charges Elec	6,948,784
4510000 Misc Service Revenues	3,224,656
4510001 Misc Ser Rev Return Ck Fees	713,431
4510600 Investigative Charges	137,317
4530000 Sales Of Water _ Water Power	375,190
Misc Service Revenue Total	11,399,378
Other Electric Revenues	
4491000 Provision For Rate Refunds	0
4560000 Other Elec Revenue	(123,539)
4560100 Oth Elec Rev Timber Sales	23,596
4560200 Oth Elec Rev Recreat Facilits	166,739
4560300 Oth Elec Rev Lk Murr Prmt Fees	45,515
4560400 Oth Elec Rev Fish And Wildlife	40,050
4561000 Rev From Trans Of Elec Of Othr	3,058,850
4560004 - Tth Elec Rev Qre Agreements	10,500
4561001 - Revenue - Orangeburg Transmiss	5,173,431
4561002 - Revenue - Winnsboro Transmissi	398,776
Other Electric Revenues Total	8,793,918
Rent from Electric Property	
4540001 Rent From Elec Property	7,590,023
4540003 Imbalance Penalty Service	4,204
Rent from Electric Property Total	7,594,227
Other Operating Revenue Total	**38,993,674**
1 Revenues Total	**2,626,725,028**
2 Fuel	
Fuel & Purchased Power	
Fuel	
5010000 Oper Fuel Steam Pwr	235,994,780
5010099 Chemicals - Fuel Clause	7,233,722
5010100 Fuel Handling Exp Steam Pwr	2,650,789
5091010 Oper So2 Arp Allow Exp	7,474
5180000 Oper Nuc Fuel Exp Nuc Pwr	44,981,357
5470000 Oper Fuel Oth Pwr	194,187,929
5010200 - Fuel Exp-nndeadhead Billing	(1,291,827)
4073020 - Amort Der Avoided Costs Deferr	4,060,203
4073021 - Amort Der Incremental O&m Cost	373,404
4073022 - Amort Der Incremental Capital	824,534
Fuel Total	489,022,366
Purchased Power	
5550000 Pur Pwr Non Assoc Oth Pwr Sup	1,969,100
5550001 Pur Pwr Assoc Co Oth Pwr Sup	190,581,625
5550003 Purchased Power - Pr1 Customer	20,948
5550004 Prch Pwr - Amort Of Def Exps	282,658
5550005 Prch Pwr - Mjm Accrual Act Rev	(2,295,949)
5550100 Pur Pwr Pwr Sup Nmst & Emerg	14,519,783

RESPONSE NO. 1-24

	Electric Amount
5550200 Prch Pwr - Amort Def Capacity	296,000
5550010 - Pur Pwr Non Der Solar	201,479
5550201 - Prch Pwr - Long-term Ppa	50,931,905
Purchased Power Total	256,507,550
Fuel & Purchased Power Total	**745,529,915**
2 Fuel Total	**745,529,915**
3 Variable O&M	
A&G Maintenance	
A&G Maintenance	
9320000 Maintenace Of General Plant	1,215
9350000 A And G Maint General Plant	5,621,565
9350001 A And G Environ Exp	230,745
9350010 Maint - Transportation And Poe	1,110
9350020 Maint Of Communication Eqpmnt	558,279
9350030 Maint Of Office Furn And Equip	64,525
9350040 Maintenance Of Other Equipment	13,215
A&G Maintenance Total	6,490,655
A&G Maintenance Total	**6,490,655**
A&G Operations	
A&G Operations	
9200000 A And G Salaries	44,897,639
9200001 Accrue Vacation Carryover	(342,125)
9200003 A And G Salaries Bonus	8,689,970
9210000 A And G Off Supp And Expenses	13,142,322
9230000 A And G Outside Svcs	14,691,093
9240000 A And G Property Insurance	7,084,913
9250000 A And G Injuries And Damages	9,395,774
9260000 A And G Pension	3,682,443
9260001 A And G Benefits	37,662,103
9260002 A And G Pens And Bene Vcs Opeb	705,187
9270000 A And G Franch Requirements	13,296
9280000 A And G Reg Comm Exps	5,197,951
9290000 A And G Duplicate Chgs Cr	(9,601,907)
9301000 A And G Gen Advert Exps	20,419
9302000 A And G Misc Gen Exps	4,191,018
9310000 A And G Rents	3,968,343
9260004 - Retail Electric Pension Rider	12,981,875
9260005 - Non Retail Electric Pension Ex	256,083
9310015 - Rents - Aircraft	1,162,319
A&G Operations Total	157,798,715
A&G Operations Total	**157,798,715**
Customer Accounts	
Customer Accounts	
9010000 Supervision Cust Acct	1,158,406
9020000 Meter Reading Exp Cust Acct	1,890,144

RESPONSE NO. 1-24

	Electric Amount
9030001 Billing & Accntng Exp Cust Act	17,335,252
9030002 Collecting Exp Cust Acct	4,676,512
9030003 Contrct & Orders Exp Cust Acct	13,700,464
9040000 Uncollectbl Accnts Cust Acct	6,232,131
9050000 Misc Cust Accnts Exp Cust Acct	2,840,230
Customer Accounts Total	47,833,138
Customer Accounts Total	**47,833,138**
Customer Srvc & Information	
Cust Svc & Info	
9070000 Supervision Cust Serv	255,033
9080000 Customr Assistnc Exp Cust Srv	2,234,659
9080001 Rebates Cust Serv	6,150
9080003 Cust Acctg Courtesy Adjustmnts	3,200
9080004 Amortization - Demand Side Mgm	11,656,124
9100000 Misc Cust Srv/info Exp Cus	9,261
Cust Svc & Info Total	14,164,427
Customer Srvc & Information Total	**14,164,427**
Electric Maintenance	
Distribution Maintenance	
5900000 Dist Maint Superv & Engineerng	242,747
5910000 Dist Maint Structures	1,149
5920000 Dist Maint Of Stat Equipment	3,207,774
5930000 Dist Maint Oh Lines	11,861,477
5930001 Rights Of Way Re	15,279,513
5930002 Oh Lines Storm Dam Res Re	(1,912,056)
5940000 Dist Maint Undergrnd Lines	3,302,438
5950000 Dist Maint Line Transformers	124,490
5950001 Dist Maint Netwk Transformers	1,251
5950002 Dist Maint Submers Transfrmrs	0
5950003 Dist Maint Padmtd Transformers	30,644
5960000 Dist Maint St Light & Sgnl Sys	3,590,410
5970000 Dist Maint Meters	393,446
5980000 Dist Maint Misc Distrib Plant	3,232,030
5920001 - Maint Stat Equip-environmental	173,547
Distribution Maintenance Total	39,528,863
Hydro Power Maintenance	
5410000 Maint Superv And Eng Hydro Pwr	182,183
5420000 Maint Structures Hydro Pwr	9,737
5430000 Maint Rrvr Dams & Wtrwys Hydr	685,619
5440000 Maint Elec Plant Hydro Pwr	2,991,214
5450000 Maint Msc Hydrlc Plt Hydro Pwr	83,746
5450100 Maint Fish & Wildlf Hydro Pwr	0
5450200 Maint Recrtnl Faclts Hydro Pwr	49,190
Hydro Power Maintenance Total	4,001,690
Nuclear Pwr Maintenance	

RESPONSE NO. 1-24

	Electric Amount
5280000 Maint Superv & Engnrng Nuc Pwr	3,637,691
5280100 Maint Refueling Reserve Nu Pwr	(4,534,127)
5290000 Maint Structures Nuc Pwr	3,418,156
5300000 Maint Reactr Plnt Equip Nu Pwr	17,765,285
5310000 Maint Elec Plant Nuc Pwr	4,785,660
5320000 Maint Misc Nuc Plant Nuc Pwr	10,061,290
Nuclear Pwr Maintenance Total	35,133,955
Other Power Maintenance	
5510000 Maint Superv And Eng Oth Pwr	315,293
5520000 Maint Structures Oth Pwr	543,373
5530000 Maint Gen & Elec Plant Oth Pwr	12,690,510
5530001 Jasper Csa Maint Gen&elec Plnt	63,563
5530002 Urquhart - Ge Csa Maintenance	114,774
5540000 Maint Msc Oth Pwr Gen Plnt Pwr	523,784
Other Power Maintenance Total	14,251,297
Steam Pwr Maintenance	
5100000 Maint Superv And Eng Steam Pwr	79,520
5110000 Maint Structures Steam Pwr	809,881
5120000 Maint Boiler Plant Steam Pwr	12,159,439
5130000 Maint Elec Plant Steam Pwr	11,528,167
5140000 Maint Msc Steam Plnt Steam Pwr	4,596,958
Steam Pwr Maintenance Total	29,173,965
Transmission Maintenance	
5680000 Maint Super & Enginrng Trans	46,314
5690100 Maint Struct Relay-cntrl Bldg	36,650
5691000 Maint Of Computer Hardware	0
5692000 Maint Of Computer Software	96
5693000 Maint Of Communication Equip	27,105
5700000 Maint Station Equip Trans	2,853,415
5710000 Maint Overhead Lines Trans	5,486,571
5710001 Storm Damage - Reserve	(649,245)
5720000 Maint Underground Lines Trans	1,592
5730000 Maint Misc Transm Plnt Trans	163,100
5690000 - Maint Structures Trans	440
5730001 - Maint Misc Trans Pl-enrnmntl	67,560
Transmission Maintenance Total	8,033,598
Electric Maintenance Total	**130,123,369**
Electric Operations	
Distribution Operations	
5800000 Dist Oper Superv & Engineering	820,032
5810000 Dist Oper Load Dispatch	919,236
5820000 Dist Oper Stat Expenses	562,180
5830000 Dist Oper Oh Line Expenses	1,415,088
5830001 Dist Op Remv & Reset Oh Trans	27,164
5830002 Dist Op Remv & Reset Pdmnt Tra	22,998

SOUTH CAROLINA ELECTRIC & GAS — Income Statement Reconciliation
OFFICE OF REGULATORY STAFF AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E, 2017-305-E, 2017-370-E

RESPONSE NO. 1-24

	Electric Amount
5840000 Dist Oper Undergrnd Line Exp	233,658
5850000 Dist Op St Light & Sgnl Sys Ex	332,101
5860000 Dist Oper Meter Expenses	1,218,867
5870000 Dist Oper Cust Install Exp	31,382
5870002 Dist Cust Instl Amt Bill Cust	(4,596)
5880000 Dist Oper Misc Distrib Expns	9,210,683
5880001 Dist Oper Environ Expenses	37,459
5890000 Dist Oper Rents	2,222,908
5840001 - Dist Oper Netwk Transformers	23
Distribution Operations Total	17,049,181
Nuclear Pwr Operations	
5170000 Oper Superv And Eng Nuc Pwr	12,853,828
5190000 Oper Coolants & Water Nuc Pwr	3,394,266
5200000 Oper Steam Expenses Nuc Pwr	7,608,473
5230000 Oper Elec Expenses Nuc Pwr	3,107,715
5240000 Oper Misc Nuc Pwr Exp Nuc Pwr	38,903,839
5240100 Op Msc Nu Pwr Decom Exp Nu Pwr	3,224,920
5240200 Oper Refuel Reserve Nuc Pwr	(325,047)
Nuclear Pwr Operations Total	68,767,994
Other Pwr Operations	
5460000 Oper Superv & Enginrng Oth Pw.	1,128,206
5480000 Oper Generation Exp Oth Pwr	4,778,133
5490000 Op Msc Oth Prw Gen Exp Oth Pwr	1,470,652
5500000 Oper Rents Oth Pwr	43,200
Other Pwr Operations Total	7,420,191
Other Pwr Supply Operations	
5560000 Sys Cntrl & Load Dsptch Pwr	2,695,337
5570000 Other Expenses Oth Pwr Supply	0
5570100 Stndby Gen Stndby Fees Pwr Sup	296,474
5570101 Stndby Gen Fuel-maint Supp Oth	0
Other Pwr Supply Operations Total	2,991,811
Steam Pwr Operations	
5000000 Oper Superv And Eng Steam Pwr	2,757,038
5020000 Oper Steam Expenses Steam Pwr	17,175,102
5050000 Oper Elec Expenses Steam Pwr	6,099,902
5060000 Op Msc Steam Pwr Exp Steam Pwr	6,333,609
Steam Pwr Operations Total	32,365,650
Transmission Operations	
5600000 Oper Supervsn & Enginrng Tran	793,539
5610000 Oper Load Dispatching Trans	0
5611000 Load Dispatch-reliability	1,023,783
5612000 Load Dispatch-monitor And Oper	906,448
5613000 Load Dispatch-trans Serv And S	176,400
5615000 Relia Planning And Stndrd Deve	46,635
5616000 Transmission Service Studies	36

	Electric Amount
5617000 Generation Interconnect Studie	(106,606)
5620000 Oper Station Expenses Trans	2,337,627
5630000 Oper Oh Line Expenses Trans	2,107
5650000 Oper Trans-elec By Others Tran	2,874,984
5660000 Oper Misc Trans Exps Trans	4,252,424
5670000 Oper Rents Trans	347,982
5660100 - Op Trans Impct Stud Natve Load	45,782
Transmission Operations Total	12,701,141
Electric Operations Total	**141,295,968**
Hydro Power Operations	
Hydro Power Operations	
5350000 Oper Superv And Eng Hydro Pwr	686,027
5370000 Oper Hydraulic Exp Hydro Pwr	447,279
5370100 Oper Fish & Wildlife Hydro Pwr	0
5370200 Oper Recreationl Fac Hydro Pwr	368,628
5370300 Oper Lake Murray Mgt Hydro Pwr	548,965
5370301 Op Lake Montcllo Mgt Hydro Pwr	2,072
5380000 Oper Elec Expenses Hydro Pwr	165,724
5390000 Op Msc Hydrlc Pwr Gen Hydr Pwr	660,866
Hydro Power Operations Total	2,879,562
Hydro Power Operations Total	**2,879,562**
Sales	
Sales	
9120000 Demonstrtng & Sellng Exp Sales	1,131,480
9130000 Advertising Exp Sales	1,429
9160000 Misc Sales Exp Sales	354,565
9110000 - Supervision Sales	652
Sales Total	1,488,125
Sales Total	**1,488,125**
3 Variable O&M Total	**502,073,959**
4 Taxes Other Than Income	
Taxes Other than Income	
Taxes Other than Income	
4081000 Tx Oth Than Inc Tx Util	210,682,693
Taxes Other than Income Total	210,682,693
Taxes Other than Income Total	**210,682,693**
4 Taxes Other Than Income Total	**210,682,693**
5 Depreciation & Amortization	
5 Depreciation & Amortization	
5 Depreciation & Amortization	
4030000 Depreciation Expense	231,865,141
4035000 Depr Expense - Synfuel Credits	1,131,676
4040000 Amortization Expense	8,696,868
4040003 Westvaco Gen Amort Expense	884,096
4060002 Amort Plt Acq Adj-hagood Turb	854,201

RESPONSE NO. 1-24

	Electric Amount
4070005 Amortization Of Chas-franchise	1,357,440
4070006 Amortization Of Cola-franchise	2,825,785
4140500 Amort For Scana Software	2,447,906
4140550 Depr For Scana Assets	9,003,495
4070010 - Amort Can1 Unrecovered Plant	1,607,593
4070011 - Amort Can2-3 Unrecovered Plant	12,270,624
4073010 - Amort Wateree Scrubber Def	1,061,940
5 Depreciation & Amortization Total	274,006,765
5 Depreciation & Amortization Total	**274,006,765**
5 Depreciation & Amortization Total	**274,006,765**

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)

Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
South Carolina Electric & Gas Company	**End of** 2016/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION	
01 Exact Legal Name of Respondent South Carolina Electric & Gas Company	02 Year/Period of Report End of 2016/Q4
03 Previous Name and Date of Change *(if name changed during year)*	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 100 SCANA Parkway, Cayce, SC 29033-3712	
05 Name of Contact Person Lisa Honeycutt	06 Title of Contact Person Accounting Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 Operation Way - MC B131, Cayce, SC 29033-3701	

08 Telephone of Contact Person*Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(803) 217-7416	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Jimmy E. Addison	Jimmy E. Addison	04/13/2017
02 Title Executive Vice President and CFO		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

James E. Swan, IV, Vice President and Controller
100 SCANA Parkway
Cayce, SC 29033-3712

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

South Carolina - July 19, 1924

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

South Carolina - Electric, Gas

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

The respondent is a wholly-owned subsidiary of SCANA Corporation (SCANA). SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA holds directly all of the capital stock of the respondent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	South Carolina Fuel Company, Inc.	Acquires, owns, provides	None	
2		financing for and sells at		
3		cost to SCE&G nuclear fuel,		
4		certain fossil fuels and		
5		emission allowances.		
6				
7	South Carolina Generating Company, Inc.	Owns A. M. Williams	None	
8		Generating Station and sells		
9		electricity solely to SCE&G.		
10				
11	SRFI, LLC	A single member LLC	None	
12		holding investments in		
13		companies involved with		
14		re-engineered fuel.		
15				
16	APOG, LLC	Provides technical,	None	
17		engineering and procurement		
18		support services to and for		
19		the benefit of members and		
20		their licensing, development		
21		and construction of AP1000		
22		nuclear power plants.		
23				
24				
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Canadys Refined Coal, LLC	Manufactures and sells	None	
2		refined coal to reduce		
3		emissions.		
4				
5	Brandon Shores Coaltech, LLC	Manufactures and sells	None	
6		refined coal to reduce		
7		emissions.		
8				
9	Louisa Refined Coal, LLC	Manufactures and sells	None	
10		refined coal to reduce		
11		emissions.		
12				
13	Carolinas Virginia Nuclear Power	A non-profit corporation	None	
14	Associates, Inc. (CVNPA)	formed in 1956 by member		
15		companies to jointly study		
16		economic ways to produce and		
17		utilize nuclear material and		
18		atomic energy. Operated a		
19		nuclear power plant from		
20		1963 - 1967.		
21				
22	Brunner Island Refined Coal, LLC	Manufactures and sells	None	
23		refined coal to reduce		
24		emissions.		
25				
26				
27				

Schedule Page: 103 Line No.: 1 Column: d

Control held by SCE&G under the terms of a fuel contract. The accounts of SCFC are fully consolidated herein.

Schedule Page: 103 Line No.: 7 Column: d

SCE&G has determined that it has a controlling financial interest in South Carolina Generating Company, Inc. under the terms of a Power Purchase Agreement. Accordingly, SCE&G consolidates the accounts of South Carolina Generating Company, Inc. for financial reporting under Generally Accepted Accounting Principles. Since South Carolina Generating Company, Inc. is a separate FERC reporting entity and per guidance from FERC staff, South Carolina Generating Company, Inc. has not been consolidated in this Form 1 report.

Schedule Page: 103 Line No.: 11 Column: d

SRFI, LLC is a single member LLC in which SCE&G is the sole member and no stock was issued.

Schedule Page: 103 Line No.: 16 Column: d

SCE&G holds a 25% interest in APOG, LLC. Other members include Duke Energy, Southern Nuclear Operating Company and Florida Power & Light Company.

Schedule Page: 103.1 Line No.: 1 Column: d

SCE&G holds a 40% interest in Canadys Refined Coal, LLC. The other member is AJG Coal, Inc.

Schedule Page: 103.1 Line No.: 5 Column: d

SCE&G holds a 10% interest in Brandon Shores Coaltech, LLC. Other members include AJG Coal, Inc. and BSW Refined Coal.

Schedule Page: 103.1 Line No.: 9 Column: d

SCE&G holds a 10% interest in Louisa Refined Coal, LLC. Other members include AJG Coal, Inc. and LRC Holdings.

Schedule Page: 103.1 Line No.: 13 Column: d

SCE&G holds a 25% interest in CVNPA. Other members include Duke Power Company (Duke Energy Carolinas, LLC), Carolina Power & Light Company (Duke Energy Progress) and Virginia Electric and Power Company (Dominion Virginia Power).

Schedule Page: 103.1 Line No.: 22 Column: d

SCE&G holds a 20% interest in Brunner Island Refined Coal, LLC. The other member is AJG Coal, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	Chairman and Chief Executive Officer	Kevin B. Marsh	1,038,607
3	Chief Operating Officer and President of Generation		
4	and Transmission	Stephen A. Byrne	631,296
5	President of Retail Operations	W. Keller Kissam	384,681
6	President of Gas Operations	D. Russell Harris	220,399
7	Executive Vice President and		
8	Chief Financial Officer	Jimmy E. Addison	473,624
9	Senior Vice President - Risk Management and		
10	Corporate Compliance (Effective 1/16)	Sarena D. Burch	228,965
11	Senior Vice President, General Counsel		
12	and Assistant Secretary	Ronald T. Lindsay	289,351
13	Senior Vice President Administration (Through 11/16)		
14	Senior Vice President of Special Projects		
15	(Effective 11/16, Retired 12/16)	Martin K. Phalen	293,843
16	Chief Information Officer (Through 2/16) Vice President		
17	and Chief Information Officer (Through 11/16)		
18	Senior Vice President		
19	Administration (Effective 11/16)	Randal M. Senn	250,198
20	Senior Vice President and Chief Nuclear Officer	Jeffrey B. Archie	383,751
21	Senior Vice President of Economic Development,		
22	Governmental & Regulatory Affairs	Kenneth R. Jackson	257,328
23	Vice President of Governmental Affairs	Henry E. Barton, Jr.	137,737
24	Vice President of Human Resources	Annmarie C. Higgins	216,508
25	Vice President of Marketing and Communications	Catherine B. Love	170,028
26	Vice President of Electric Operations	William J. Turner, III	216,527
27	Vice President of Gas Operations	Felicia R. Howard	218,414
28	Vice President of Gas Services	M. Shaun Randall	91,111
29	Vice President of Fossil Hydro	James M. Landreth	256,883
30	Vice President of Customer Relations and		
31	Renewables	Daniel F. Kassis	223,541
32	Vice President of Customer Service	Samuel L. Dozier	175,626
33	Vice President of SCANA Support		
34	Services (Effective 11/16)	Cedric F. Green	149,563
35	Vice President of Electric Transmission	Pandelis N. Xanthakos	180,814
36	Vice President of New Nuclear		
37	Operations (Through 11/16) Vice President		
38	Nuclear Construction and Startup (Effective 11/16)	Ronald A. Jones	300,410
39	Vice President of Nuclear Operations (Through 1/16)		
40	Vice President of Nuclear Support Services		
41	Services (Through 11/16) Vice President of		
42	Nuclear Operations Units 2/3 (Effective 11/16)	Thomas D. Gatlin	307,110
43	Vice President of Nuclear Operations (Effective 1/16)	George A. Lippard, III	254,236
44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Vice President of Nuclear Financial		
2	Administration (Retired 6/16)	Carlette L. Walker	143,499
3	Treasurer and Risk Management		
4	Officer (Through 2/16) Vice President and		
5	Treasurer (Effective 2/16)	Mark R. Cannon	190,936
6	Secretary (Through 2/16) Vice President and		
7	Secretary (Effective 2/16)	Gina S. Champion	181,652
8	Vice President of Finance (Effective 11/16)		
9	and Treasurer (Effective 3/17)	Iris N. Griffin	105,957
10	Controller (Through 2/16) Vice President and		
11	Controller (Effective 2/16)	James E. Swan, IV	216,946
12	Vice President of SCANA Support		
13	Services (Through 11/16) Vice President and Chief		
14	Information Officer (Effective 11/16)	Stacy O. Shuler, Jr.	178,531
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Schedule Page: 104 Line No.: 1 Column: c

Amounts reported reflect the portion of the officer's salary that was assigned to the respondent during the reporting period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	G. E. Aliff***	Reston, Virginia
2	J. A. Bennett***	Columbia, South Carolina
3	J. F.A.V. Cecil	Asheville, North Carolina
4	S. A. Decker	Mill Spring, North Carolina
5	D. M. Hagood***	Charleston, South Carolina
6	J. M. Micali***	Boston, Massachusetts
7	L. M. Miller	Great Falls, Virginia
8	J. W. Roquemore***	Orangeburg, South Carolina
9	M. K. Sloan	Durham, North Carolina
10	H.C. Stowe***	Pawley's Island, South Carolina
11	A. Trujillo	Atlanta, Georgia
12	K. B. Marsh, Chairman	
13	and Chief Executive Officer of	
14	SCANA Corporation and SCE&G**	Cayce, South Carolina
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Schedule 1, Schedule 7, Schedule 8, Attachment 8	ER10-516
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20160513-5152	05/13/2016	ER10-516	Annual Update Infomational Filing	Schedule 1, 7, 8, Attachment H
2					
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. Three 20-year municipal electric and gas franchise agreements were established during the second quarter of 2016 without payment of consideration.

One 20-year municipal electric and gas franchise agreement was established during the third quarter of 2016 without payment of consideration.

One 20-year municipal electric franchise agreement was established during the fourth quarter of 2016 without payment of consideration.

2. None

3. None

4. None

5. None

6. The Company's obligations under short-term borrowing arrangements on the respective Balance Sheet dates were as follows:

12/31/2016	12/31/2015
$804,321,000	$420,225,000

Such short-term borrowings have been authorized by FERC (Docket Nos. ES14-48-000 and ES16-51-000).

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&Gs construction program, to finance capital expenditures, and for general corporate purposes.

Such long-term borrowings have been authorized by the SCPSC (Docket Nos. 2013-132-E and 2010-317-E).

For additional information, see Notes 4, 6 and 7 to the Financial Statements.

7. None

8. None

9. See Notes 2 and 10 to the Financial Statements.

10. None

11. (Reserved)

12. Not Applicable

13. The following changes in Company Officers and Directors became effective during 2016:

Sharon A. Decker and Gregory E. Aliff were appointed to the Company’s Board of Directors.

Harold C. Stowe retired from the Company's Board of Directors.

Sarena D. Burch, formerly Senior Vice President – Fuel Procurement & Asset Management, was appointed Senior Vice President – Risk Management & Corporate Compliance.

Thomas D. Gatlin, formerly Vice President of Nuclear Operations, was appointed Vice President of Nuclear Support Services, January 2016 - November 2016. Effective November 2016, Mr. Gatlin was appointed Vice President of Nuclear Operations Units 2/3.

George A. Lippard, III was appointed Vice President of Nuclear Operations.

James E. Swan, IV, Controller, was named Vice President and Controller.

Randall M. Senn, Chief Information Officer, was named Vice President and Chief Information Officer February 2016 - November 2016. Effective November 2016, Mr. Senn was appointed Senior Vice President Administration.

Gina S. Champion, Secretary, was named Vice President and Secretary.

Mark R. Cannon, Treasurer and Risk Management Officer, was named Vice President and Treasurer. Mr. Cannon retired effective February 28, 2017.

Carlette L. Walker, Vice President of Nuclear Financial Administration, retired.

Martin K. Phalen, Senior Vice President Administration, assumed duties as Senior Vice President of Special Projects until his December 31, 2016 retirement date.

Stacy O. Shuler, Jr. Vice President of SCANA Support Services, was appointed Vice President and Chief Information Officer.

Cedric F. Green was appointed Vice President of SCANA Support Services.

Iris N. Griffin was appointed Vice President of Finance. On March 1, 2017, Mrs. Griffin assumed duties of Treasurer in addition to her responsibilities as Vice President of Finance.

Ronald A. Jones, formerly Vice President of New Nuclear Operations was appointed Vice President of Nuclear Construction and Startup.

14. Not Applicable

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	10,808,517,861	10,456,789,235
3	Construction Work in Progress (107)	200-201	4,808,038,309	3,990,834,928
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		15,616,556,170	14,447,624,163
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,271,191,389	4,149,318,951
6	Net Utility Plant (Enter Total of line 4 less 5)		11,345,364,781	10,298,305,212
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	144,178,325	81,161,353
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		72,615,225	116,928,535
9	Nuclear Fuel Assemblies in Reactor (120.3)		223,723,883	223,038,612
10	Spent Nuclear Fuel (120.4)		673,993,828	673,993,828
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	843,261,889	786,794,670
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		271,249,372	308,327,658
14	Net Utility Plant (Enter Total of lines 6 and 13)		11,616,614,153	10,606,632,870
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		69,793,932	68,776,649
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,064,999	1,108,780
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,856,380	1,394,608
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		61,516	61,516
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		122,840,806	114,983,724
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		70,585,791	4,539,044
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		265,073,426	188,646,761
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		160,445,414	127,896,448
36	Special Deposits (132-134)		187,012	12,236,393
37	Working Fund (135)		60,525	62,025
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		249,194,592	218,883,482
41	Other Accounts Receivable (143)		155,928,285	201,397,221
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,239,931	2,964,230
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		4,731,796	9,450,009
45	Fuel Stock (151)	227	46,289,912	57,600,683
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	134,522,151	128,029,866
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	640,580	656,143

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	351
55	Gas Stored Underground - Current (164.1)		11,124,020	15,144,464
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		7,705,351	8,250,772
57	Prepayments (165)		87,029,102	82,477,535
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		121,727	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		117,626,653	101,515,765
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		70,585,791	14,895,948
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		70,585,791	4,539,044
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		972,367,189	970,993,831
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		35,470,866	31,259,886
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	118,538,678	126,656,202
72	Other Regulatory Assets (182.3)	232	1,903,279,248	1,703,585,141
73	Prelim. Survey and Investigation Charges (Electric) (183)		709,896	198,470
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	165,241,815	84,634,918
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		15,116,379	16,258,765
82	Accumulated Deferred Income Taxes (190)	234	289,147,004	276,025,196
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,527,503,886	2,238,618,578
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		15,381,558,654	14,004,892,040

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2016/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	576,405,122	576,405,122
3	Preferred Stock Issued (204)	250-251	100,000	100,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	2,288,167,716	2,188,167,716
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	4,335,379	4,335,379
11	Retained Earnings (215, 215.1, 216)	118-119	2,481,211,937	2,265,470,454
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-2,973,265	-2,770,003
16	Total Proprietary Capital (lines 2 through 15)		5,338,576,131	5,023,037,910
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,928,770,000	4,428,770,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	265,579	100,185,967
22	Unamortized Premium on Long-Term Debt (225)		24,319,529	24,981,816
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		24,038,677	22,751,632
24	Total Long-Term Debt (lines 18 through 23)		4,929,316,431	4,531,186,151
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		20,678,011	12,477,819
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		7,859,531	5,355,089
29	Accumulated Provision for Pensions and Benefits (228.3)		233,863,772	186,867,019
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		3,371,455	21,708,781
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		509,434,012	476,223,696
35	Total Other Noncurrent Liabilities (lines 26 through 34)		775,206,781	702,632,404
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		804,321,000	420,225,000
38	Accounts Payable (232)		233,861,353	450,763,775
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		90,213,959	77,601,960
41	Customer Deposits (235)		60,283,425	57,087,060
42	Taxes Accrued (236)	262-263	190,023,234	337,368,808
43	Interest Accrued (237)		66,075,852	64,981,070
44	Dividends Declared (238)		77,500,000	72,300,000
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		8,495,957	8,534,964
48	Miscellaneous Current and Accrued Liabilities (242)		64,185,149	71,869,175
49	Obligations Under Capital Leases-Current (243)		5,341,366	3,860,666
50	Derivative Instrument Liabilities (244)		29,862,614	54,566,151
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		3,371,455	21,708,781
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,626,792,454	1,597,449,848
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	22,188,300	23,580,500
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	60,685,179	69,255,823
60	Other Regulatory Liabilities (254)	278	238,845,948	147,235,196
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	12,039,300	12,361,300
63	Accum. Deferred Income Taxes-Other Property (282)		2,003,667,530	1,532,935,108
64	Accum. Deferred Income Taxes-Other (283)		374,240,600	365,217,800
65	Total Deferred Credits (lines 56 through 64)		2,711,666,857	2,150,585,727
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		15,381,558,654	14,004,892,040

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,986,197,254	2,929,818,797		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,346,876,575	1,397,711,033		
5	Maintenance Expenses (402)	320-323	147,981,511	150,487,404		
6	Depreciation Expense (403)	336-337	254,702,412	246,035,441		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	8,989,523	9,373,615		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	860,418	860,418		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		18,061,442	18,061,442		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		5,655,182	1,061,940		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	227,416,255	210,726,419		
15	Income Taxes - Federal (409.1)	262-263	-149,609,400	213,774,190		
16	- Other (409.1)	262-263	-19,006,840	31,833,545		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	673,023,500	279,501,015		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	255,031,632	294,732,032		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,392,200	-2,371,100		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,258,526,746	2,262,323,330		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		727,670,508	667,495,467		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2016/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,619,373,876	2,557,104,822	366,823,378	372,713,975			2
						3
1,100,037,139	1,143,617,023	246,839,436	254,094,010			4
138,310,848	142,330,167	9,670,663	8,157,237			5
228,393,600	220,178,807	26,308,812	25,856,634			6
						7
8,037,130	8,443,725	952,393	929,890			8
854,201	854,201	6,217	6,217			9
18,061,442	18,061,442					10
						11
5,655,182	1,061,940					12
						13
200,637,124	185,840,612	26,779,131	24,885,807			14
-144,978,100	212,968,289	-4,631,300	805,901			15
-18,767,040	31,801,445	-239,800	32,100			16
641,198,000	253,565,716	31,825,500	25,935,299			17
241,225,732	281,879,832	13,805,900	12,852,200			18
-1,279,600	-1,285,700	-112,600	-1,085,400			19
						20
						21
						22
						23
						24
1,934,934,194	1,935,557,835	323,592,552	326,765,495			25
684,439,682	621,546,987	43,230,826	45,948,480			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		727,670,508	667,495,467		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		7,423,708	7,102,682		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		4,907,731	4,357,022		
33	Revenues From Nonutility Operations (417)		92,172			
34	(Less) Expenses of Nonutility Operations (417.1)		673,974	613,039		
35	Nonoperating Rental Income (418)		150,223	123,848		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,095,182	-4,827,566		
37	Interest and Dividend Income (419)		5,458,249	3,795,907		
38	Allowance for Other Funds Used During Construction (419.1)		26,082,377	24,828,339		
39	Miscellaneous Nonoperating Income (421)		16,068,854	16,450,885		
40	Gain on Disposition of Property (421.1)		621,436	4,048,536		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		46,220,132	46,552,570		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		33,834	33,834		
45	Donations (426.1)		3,245,411	8,408,608		
46	Life Insurance (426.2)		28,544	58,652		
47	Penalties (426.3)			-49,866		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,535,302	2,622,234		
49	Other Deductions (426.5)		8,827,081	9,538,330		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		13,670,172	20,611,792		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	660,927	377,023		
53	Income Taxes-Federal (409.2)	262-263	-6,033,035	-7,631,612		
54	Income Taxes-Other (409.2)	262-263	485,364	-533,991		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	5,673,000	6,674,300		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	7,892,900	3,608,029		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-7,106,644	-4,722,309		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		39,656,604	30,663,087		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		253,679,997	231,189,035		
63	Amort. of Debt Disc. and Expense (428)		2,940,265	2,844,059		
64	Amortization of Loss on Reaquired Debt (428.1)		1,142,386	1,429,139		
65	(Less) Amort. of Premium on Debt-Credit (429)		662,287	637,373		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		6,296,983	6,818,827		
68	Other Interest Expense (431)		9,290,728	4,737,747		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		18,052,443	14,003,579		
70	Net Interest Charges (Total of lines 62 thru 69)		254,635,629	232,377,855		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		512,691,483	465,780,699		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		512,691,483	465,780,699		

Schedule Page: 114 Line No.: 4 Column: g

Includes depreciation charges of $8,806,401, amortization charges of $2,345,890 and property taxes of $2,375,729 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: h

Includes depreciation charges of $7,782,561, amortization charges of $2,192,696 and property taxes of $1,927,680 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: i

Includes depreciation charges of $935,326, amortization charges of $200,122 and property taxes of $202,680 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: j

Includes depreciation charges of $861,282, amortization charges of $190,162 and property taxes of $167,477 billed from SCANA Services.

Schedule Page: 114 Line No.: 39 Column: d

In SCPSC Docket No. 2014-44-E, the SCPSC authorized the Company to utilize interest rate derivative settlement gains to offset the ongoing DSM Lost Revenues through April 2015. Accordingly, during 2015 the Company recognized $5,189,042 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,193,031,209	2,009,500,783
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		516,786,665	470,608,265
17	Appropriations of Retained Earnings (Acct. 436)			
18	See Note 3 to Financial Statements	215.1	-6,554,471	(4,750,273)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-6,554,471	(4,750,273)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31		238	-296,950,000	(277,500,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-296,950,000	(277,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-4,095,182	(4,827,566)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,402,218,221	2,193,031,209
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		78,993,716	72,439,245
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		78,993,716	72,439,245
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,481,211,937	2,265,470,454
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		-4,095,182	(4,827,566)
51	(Less) Dividends Received (Debit)			
52	Funded Equity Method losses		4,095,182	4,827,566
53	Balance-End of Year (Total lines 49 thru 52)			

Schedule Page: 118 Line No.: 50 Column: c

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

Schedule Page: 118 Line No.: 52 Column: c

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	512,691,483	465,780,699
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	254,816,443	246,203,515
5	Amortization of Utility Plant and Acquisition Adjustment	9,883,775	10,267,867
6	Amortization - DER, Muni Franchise, Unrecovered Plt, & OCI	23,886,561	19,314,459
7	Amortization of Nuclear Fuel	56,467,219	45,687,791
8	Deferred Income Taxes (Net)	466,437,214	-9,862,347
9	Investment Tax Credit Adjustment (Net)	-1,392,200	-2,371,100
10	Net (Increase) Decrease in Receivables	-106,019,875	138,604,283
11	Net (Increase) Decrease in Inventory	-33,502,669	-38,218,180
12	Net (Increase) Decrease in Allowances Inventory	15,563	19,389
13	Net Increase (Decrease) in Payables and Accrued Expenses	-133,163,069	161,668,383
14	Net (Increase) Decrease in Other Regulatory Assets	-58,647,509	34,579,717
15	Net Increase (Decrease) in Other Regulatory Liabilities	35,920,913	12,933,219
16	(Less) Allowance for Other Funds Used During Construction	26,082,377	24,828,339
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-92,480,187	-19,891,407
19	Discount / Premium on Long-Term Debt	-98,464	-125,075
20	Carrying Cost Recovery	-16,654,733	-12,330,778
21	(Gain) / Loss on Disposition of Assets	-1,315,217	-4,379,390
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	890,762,871	1,023,052,706
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,332,925,131	-943,892,487
27	Gross Additions to Nuclear Fuel	-71,594,316	-76,368,193
28	Gross Additions to Common Utility Plant	-11,090,849	-13,825,300
29	Gross Additions to Nonutility Plant	-613,377	-1,028,958
30	(Less) Allowance for Other Funds Used During Construction	-26,082,377	-24,828,339
31	Other (provide details in footnote):		
32	Salvage Received	3,331,278	7,761,255
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,386,810,018	-1,002,525,344
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Proceeds from Sale of Fixed Assets and Investments	46,858,251	7,986,126
39	Investments in and Advances to Assoc. and Subsidiary Companies	-5,345,411	-4,061,149
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Settlement of Interest Rate Swaps		10,278,883
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Investments in Utility Money Pool		-9,420,000
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Return of Investments from Utility Money Pool	9,420,000	80,000,000
54	Other Investments	10,391,301	84,796,178
55	Settlement of Interest Rate Swaps	-113,015,868	-262,844,303
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,438,501,745	-1,095,789,609
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	500,000,000	500,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Contributions from Parent	100,000,000	204,414,449
66	Net Increase in Short-Term Debt (c)	384,096,000	
67	Other (provide details in footnote):		
68	Borrowings from Utility Money Pool		521,400,000
69	Deferred Financing Costs / Long-Term Debt Issuance Costs	-7,112,918	-10,729,017
70	Cash Provided by Outside Sources (Total 61 thru 69)	976,983,082	1,215,085,432
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-104,946,742	-3,880,073
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Borrowings from Utility Money Pool		-538,187,861
78	Net Decrease in Short-Term Debt (c)		-288,422,000
79	Return of Capital Contributions to Parent		-3,501,500
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-291,750,000	-277,700,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	580,286,340	103,393,998
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	32,547,466	30,657,095
87			
88	Cash and Cash Equivalents at Beginning of Period	127,958,473	97,301,378
89			
90	Cash and Cash Equivalents at End of period	160,505,939	127,958,473

Schedule Page: 120 Line No.: 14 Column: c

Certain prior period amounts, related to non-cash changes in fair value of interest rate swaps, have been reclassified within Operating Activities to conform to the current period presentation. Specifically, ($180,016,685) was reclassified from Net (Increase) Decrease in Other Regulatory Assets and ($4,617,067) was reclassified from Net Increase (Decrease) in Other Regulatory Liabilities, with an offsetting reclassification in Other. These reclassifications had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the Statement of Cash Flows.

Schedule Page: 120 Line No.: 15 Column: c

Certain prior period amounts, related to non-cash changes in fair value of interest rate swaps, have been reclassified within Operating Activities to conform to the current period presentation. Specifically, ($180,016,685) was reclassified from Net (Increase) Decrease in Other Regulatory Assets and ($4,617,067) was reclassified from Net Increase (Decrease) in Other Regulatory Liabilities, with an offsetting reclassification in Other. These reclassifications had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the Statement of Cash Flows.

Schedule Page: 120 Line No.: 18 Column: b

Includes $46,996,753 for changes in the Company's net postretirement benefit obligation, ($4,551,567) for Prepayments, ($31,563,685) for Cost of Removal, $3,196,365 for Customer Deposits, $72,124,423 receivable for federal tax refund, and various other Balance Sheet changes not presented as separate line items.

Schedule Page: 120 Line No.: 18 Column: c

Includes $141,794 for changes in the Company's net postretirement benefit obligation, ($13,798,937) for Prepayments, ($27,988,645) for Cost of Removal, $2,272,187 for Customer Deposits, and various other Balance Sheet changes not presented as separate line items.

Certain prior period amounts, related to non-cash changes in fair value of interest rate swaps, have been reclassified within Operating Activities to conform to the current period presentation. Specifically, ($180,016,685) was reclassified from Net (Increase) Decrease in Other Regulatory Assets and ($4,617,067) was reclassified from Net Increase (Decrease) in Other Regulatory Liabilities, with an offsetting reclassification in Other. These reclassifications had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the Statement of Cash Flows.

Schedule Page: 120 Line No.: 26 Column: b

For the twelve months ended December 31, 2016, the Company added $11,568,550 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($3,119,005) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 26 Column: c

For the twelve months ended December 31, 2015, the Company added $3,072,241 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($2,098,473) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: b

For the twelve months ended December 31, 2016, the Company added $861,564 to its Common Utility Plant Property Account (118) and reduced the same account by ($516,814) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: c

For the twelve months ended December 31, 2015, the Company added $564,796 to its Common Utility Plant Property Account (118) and reduced the same account by ($399,018) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: b

For the twelve months ended December 31, 2016, the Company added $2,277,134 to its Nonutility Property Account (121) and reduced the same account by ($1,390,535) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: c

For the twelve months ended December 31, 2015, the Company added $2,516,410 to its

Nonutility Property Account (121) and reduced the same account by ($1,364,577) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 54 Column: b

Nuclear Decommissioning Trust	($ 1,658,080)
Collateral Returned - Interest Rate Swaps	727,377,348
Collateral Posted - Interest Rate Swaps	(714,958,687)
Deposits to Like Kind Exchange Escrow Account	(369,280)
Total	$ 10,391,301

Schedule Page: 120 Line No.: 54 Column: c

Nuclear Decommissioning Trust	($ 2,086,012)
Collateral Returned - Interest Rate Swaps	934,668,640
Collateral Posted - Interest Rate Swaps	(840,119,762)
Withdrawals from Like Kind Exchange Escrow Account	1,256,673
Deposits to Like Kind Exchange Escrow Account	(8,923,361)
Total	$ 84,796,178

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(3,146,214)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				191,077
3	Preceding Quarter/Year to Date Changes in Fair Value				185,134
4	Total (lines 2 and 3)				376,211
5	Balance of Account 219 at End of Preceding Quarter/Year				(2,770,003)
6	Balance of Account 219 at Beginning of Current Year				(2,770,003)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				169,937
8	Current Quarter/Year to Date Changes in Fair Value				(373,199)
9	Total (lines 7 and 8)				(203,262)
10	Balance of Account 219 at End of Current Quarter/Year				(2,973,265)

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2016/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(3,146,214)		
2			191,077		
3			185,134		
4			376,211	465,780,699	466,156,910
5			(2,770,003)		
6			(2,770,003)		
7			169,937		
8			(373,199)		
9			(203,262)	512,691,483	512,488,221
10			(2,973,265)		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) _ A Resubmission	/ /	2016/Q4

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 1 Column: e

Lines 1-5 present information for the period 1/1/15 - 12/31/15.
Lines 6-10 present information for the period 1/1/16 - 12/31/16.

Schedule Page: 122(a)(b) Line No.: 1 Column: h

Lines 1-5 present information for the period 1/1/15 - 12/31/15.
Lines 6-10 present information for the period 1/1/16 - 12/31/16.

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2015.

Schedule Page: 122(a)(b) Line No.: 3 Column: e

Reflects amounts recognized in OCI persuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2015 (as applicable).

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2016.

Schedule Page: 122(a)(b) Line No.: 8 Column: e

Reflects amounts recognized in OCI persuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2016 (as applicable).

Schedule Page: 122(a)(b) Line No.: 10 Column: b

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: c

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: d

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: e

Other Comprehensive Income related to deferred employee benefit plan costs.

Schedule Page: 122(a)(b) Line No.: 10 Column: f

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: g

Not applicable for respondent.

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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

The basic financial statements shown on pages 110 through 122 are prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). The significant differences from the GAAP requirements are related to the classification of certain assets and liabilities to include the classification of the current portion of certain regulatory liabilities, the classification of the current portion of long term debt, the classification of certain deferred income taxes, the removal of the presentation of unrecognized tax benefits, the classification of cost of removal and the classification of debt issuance costs. In addition, the accounts of South Carolina Generating Company, Inc. (GENCO) are not consolidated herein, whereas they are so consolidated for GAAP reporting purposes.

These notes are based on the notes contained in South Carolina Electric & Gas Company's (SCE&G) Annual Report on Form 10-K filed with the United States Securities and Exchange Commission (SEC) and reflect certain reclassifications from the Uniform System of Accounts presentation shown on pages 110 through 122. As such, certain amounts included in these notes will be different from amounts shown on pages 110 through 122.

Management has evaluated the impact of events occurring after December 31, 2016 up to February 24, 2017, the date that SCE&G's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 13, 2017. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA Corporation (SCANA), a South Carolina corporation. SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in South Carolina Fuel Company, Inc. (Fuel Company) which is considered to be a variable interest entity and, accordingly, SCE&G's financial statements include the accounts of SCE&G and Fuel Company. The equity interest in Fuel Company is held solely by SCANA, SCE&G's parent.

Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current presentation, as follows:

Statements of Cash Flows - Non-cash changes in fair value of interest rate swaps were reclassified as an offset to the changes in certain assets and liabilities section within the reconciliations of Net Income to Net Cash Provided From Operating Activities as follows:

	December 31,	
Millions of dollars	2015	2014
Derivative financial instruments	$ (174)	$ 207
Regulatory assets	179	(234)
Regulatory liabilities	4	(29)
Other assets	(15)	32
Other liabilities	6	24

In addition, due to insignificance, the caption for Losses from equity method investments has been eliminated, and the amounts have been reclassified and included within the caption of Changes in Other assets.

The reclassifications above had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the consolidated statements of cash flows.

Statements of Comprehensive Income - Operating revenues and operating expenses from transactions with nonconsolidated affiliates are presented separately. A detail of such transactions is included in Note 11.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and allowance for funds used during construction (AFC), are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. SCE&G calculated AFC using average composite rates of 4.7% for 2016, 5.6% for 2015, and 6.5% for 2014. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the Public Service Commission of South Carolina (SCPSC) and further described in Note 2. The composite weighted average depreciation rates for utility plant assets were 2.56% in 2016, 2.55% in 2015 and 2.85% in 2014.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in Fuel used in electric generation and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the United States Department of Energy (DOE) under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of V. C. Summer Nuclear Station (Summer Station) Unit 1. In addition, SCE&G will jointly own and will be the operator of the Nuclear Units 2 and 3 (New Units) being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	**2016**		**2015**	
	Unit 1	**New Units**	**Unit 1**	**New Units**
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.3 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 634.4 million	—	$ 620.4 million	—
Construction work in progress	$ 167.7 million	$ 4.2 billion	$ 214.6 million	$ 3.4 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from South Carolina Public Service Authority (Santee Cooper) for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $76.2 million at December 31, 2016 and $178.8 million at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the balance sheet. Other planned major maintenance is expensed when incurred.

SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2016, and 2015, SCE&G incurred $19.5 million and $16.5 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, SCE&G accrues $17.2 million annually for its portion of the nuclear refueling outages scheduled from the spring of 2014 through the spring of 2020. Refueling outage costs incurred for which SCE&G was responsible totaled $26.8 million for the Fall 2015 outage and $1.8 million in 2016 in preparation for the Spring 2017 outage.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain SCE&G and affiliate personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Temporary cash investments having original maturities of three months or less at time of purchase are considered to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

SCE&G is included in the consolidated federal income tax returns of SCANA. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

SCE&G records costs that have been or are expected to be allowed in the ratemaking process in periods different from the periods in which the costs would be charged to expense or record revenues in periods different from the periods in which the revenues would be recorded by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations for refunds to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as Receivables - Customer or Customer deposits and customer prepayments, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Premiums, discounts and debt issuance costs are presented within long-term debt and are amortized as components of interest charges over the terms of the respective debt issues. Gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

Revenues and expenses of SCE&G's regulated activities (including those activities of segments described in Note 12) are presented within Operating Income, and all other activities are presented within Other Income (Expense).

Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $117.6 million at December 31, 2016 and $101.5 million at December 31, 2015.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a Purchased Gas Adjustment (PGA) are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a Weather Normalization Adjustment which minimizes fluctuations in gas revenues due to abnormal weather conditions.

Taxes billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

New Accounting Matters

In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance for revenue arising from contracts with customers that supersedes most earlier revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. SCE&G expects to adopt this guidance when required in the first quarter of 2018. The guidance permits adoption using a retrospective method, with options to elect certain practical expedients, or recognition of a cumulative effect in the year of initial adoption. SCE&G has not determined which method of adoption will be employed or what practical expedients may be elected. SCE&G has not determined the impact this guidance will have on its financial statements. However, the identification of implementation project team members and the analysis of contracts with customers to which the guidance might be applicable, particularly large customer contracts, have begun. In addition, activities of the FASB's Transition Resource Group for Revenue Recognition are being monitored, particularly as they relate to the required treatment under the standard of contributions in aid of construction, alternative revenue programs and the collectibility of revenue of utilities subject to rate regulation.

In May 2015, the FASB issued accounting guidance removing the requirement to categorize within the fair value hierarchy investments for which fair values are estimated using the Net Asset Value (NAV) practical expedient. Disclosures about investments in certain entities that calculate NAV per share are limited under this guidance to those investments for which the entity has elected to estimate the fair value using the NAV practical expedient. SCE&G elected to adopt this guidance on a retrospective basis. The adoption resulted in the reclassification of fair value related to the pension plan's investment in the common collective trust, joint venture interest, and limited partnership as of December 31, 2015. See Note 8.

In July 2015, the FASB issued accounting guidance intended to simplify the measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value.   SCE&G expects to adopt this guidance in the first quarter of 2017 and does not expect it to have a significant impact on its financial statements.

In January 2016, the FASB issued accounting guidance that will change how entities measure certain equity investments and financial liabilities, among other things. SCE&G expects to adopt this guidance when required in the first quarter of 2018 and has determined adoption of this guidance will not have a significant impact on its financial statements.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over 12 months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily on the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight-line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for years beginning in 2019. SCE&G has not determined what impact this guidance will have on its financial statements. However, the identification of implementation project team members and the initial identification and analysis of leasing and related contracts to which the guidance might be applicable have begun. In addition, SCE&G has begun evaluating certain third party software tools that may assist with this implementation and ongoing compliance.

In March 2016, the FASB issued accounting guidance changing how companies account for certain aspects of share-based payments to employees. Entities will be required to recognize the income tax effects of awards in the income statement when the awards vest or are settled. SCE&G adopted this guidance in the fourth quarter of 2016 and determined, based on the nature of its share-based awards practices, the adoption had no impact on its financial statements.

In June 2016, the FASB issued accounting guidance requiring the use of a current expected credit loss impairment model for certain financial instruments. The new model is applicable to trade receivables and most debt instruments, among other financial instruments, and is intended to result in certain impairment losses being recognized earlier than under current guidance. SCE&G must adopt this guidance beginning in 2020, including interim periods, though the guidance may be adopted in 2019. SCE&G has not determined when this guidance will be adopted or what impact it will have on its financial statements.

In August 2016, the FASB issued accounting guidance to reduce diversity in cash flow classification related to certain transactions. SCE&G expects to adopt this guidance when required in the first quarter of 2018 and does not anticipate that its adoption will impact its financial statements.

In October 2016, the FASB issued accounting guidance related to the tax effects of intra-entity asset transfers of assets other than inventory. An entity will be required to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. SCE&G expects to adopt this guidance in the first quarter 2017 and it is not expected to have a material impact on its financial statements.

In November 2016, the FASB issued accounting guidance related to the presentation of restricted cash on the statement of cash flows. The guidance is effective for years beginning in 2018 and SCE&G expects no impact on its financial statements.

In January 2017, the FASB issued accounting guidance to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test. The same one-step impairment test will be applied to goodwill at all reporting units, even those with zero or negative carrying amounts. The guidance is effective for years beginning in 2020, though early adoption after January 1, 2017 is allowed. SCE&G has not determined when this guidance will be adopted but does not anticipate that adoption will have a material impact on its financial statements.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments were fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act of 1982 (Nuclear Waste Act) for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the United States Court of Appeals for the District of Columbia (Court of Appeals), the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G, Office of Regulatory Staff (ORS), and certain other parties concerning SCE&G's petition for approval to participate in a Distributed Energy Resource (DER) program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 Megawatts (MW) by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million ($.12 per share) in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million ($.06 per share) with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

By order dated April 29, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties to decrease the total fuel cost component of retail electric rates. SCE&G reduced the total fuel cost component of retail electric rates to reflect lower projected fuel costs and to eliminate over-collected balances of approximately $61 million for base fuel and environmental costs over a 12-month period beginning with the first billing cycle of May 2016. SCE&G also began to recover projected DER program costs of approximately $6.9 million beginning with the first billing cycle of May 2016.

In October 2016, the SCPSC initiated its 2017 annual review of base rates for fuel costs. A public hearing for this annual review was held on April 6, 2017.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G removes from rate base certain deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $14.0 million and $9.5 million during 2016 and 2015, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these deferred income tax assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of demand reduction and energy efficiency programs (DSM Programs) for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2016	First billing cycle of May	$37.6 million
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G’s request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider is designed to allow SCE&G to recover projected pension costs, including under-collections, over a 12-month period, beginning with the first billing cycle in May 2016.

In January 2017, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved the filing would allow recovery of $37.0 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

By order dated March 1, 2017, the SCPSC approved SCE&G's request to decrease its pension costs rider. The pension rider is designed to allow SCE&G to recover projected pension costs, net of previous over-collected balances, over a 12-month period beginning with the first billing cycle in May 2017.

Electric - Base Load Review Act (BLRA)

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity (ROE). The SCPSC has approved recovery of the following amounts.

Year	Increase	Effective for bills rendered on and after	Amount	Allowed ROE	
2016	2.7%	November 27	$64.4 million	10.50%	*
2015	2.6%	October 30	$64.5 million	11.00%	
2014	2.8%	October 30	$66.2 million	11.00%	

*Applied prospectively for purposes of calculating revised rates under the BLRA on and after January 1, 2016.

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the Amendment, dated October 27, 2015 (October 2015 Amendment), to the Engineering, Procurement and Construction Agreement dated May 23, 2008 (EPC Contract). On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion, including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time. See also New Nuclear Construction in Note 10.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. The time period to file a Notice of Appeal of the SCPSC's decision with the South Carolina Supreme Court has expired for three of the four non-settling parties, and none of those parties have filed a Notice of Appeal. As for the remaining non-settling party, the time period for that party to file a Notice of Appeal has not yet expired, but as of April 13, 2017 (the filing date of this FERC Form 1 report), that party has not filed a Notice of Appeal.

Gas

The Natural Gas Rate Stabilization Act (RSA) is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2016	1.2% Increase	$4.1 million
2015	No change	—
2014	0.6% Decrease	$2.6 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2016, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, SCE&G has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	December 30, 2016	December 31, 2015
Regulatory Assets:		
Accumulated deferred income taxes	$ 293	$ 276
Asset Retirement Obligations (AROs) and related funding	388	370
Deferred employee benefit plan costs	308	294
Deferred losses on interest rate derivatives	611	526
Unrecovered plant	117	127
DSM Programs	59	61
Carrying costs on deferred tax assets related to nuclear construction	32	18
Environmental remediation costs	26	35
Deferred storm damage costs	20	—
Deferred costs related to uncertain tax position	15	—
Pipeline integrity management costs	6	4
Other	116	106
Total Regulatory Assets	$ 1,991	$ 1,817
Regulatory Liabilities:		
Asset removal costs	$ 502	$ 491
Deferred gains on interest rate derivatives	151	96
Other	14	18
Total Regulatory Liabilities	$ 667	$ 605

Accumulated deferred income tax liabilities that arise from utility operations that have not been included in customer rates are recorded as a regulatory asset. A substantial portion of these regulatory assets relates to depreciation and is expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station Unit 1 and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 11 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent SCE&G's deferred costs associated with such programs, and such deferred costs are currently being recovered over approximately five years through an approved rate rider.

Carrying costs on deferred tax assets related to nuclear construction are calculated on accumulated deferred income tax assets associated with the New Units which are not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs will be amortized over ten years beginning in approximately 2020.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G, and are expected to be recovered over periods of up to approximately 18 years.

Deferred storm damage costs represent costs incurred in excess of amounts previously collected through SCE&G's SCPSC-approved storm damage reserve, and for which SCE&G expects to receive future recovery through customer rates.

Deferred costs related to uncertain tax position primarily represent the estimated amounts of domestic production activities deductions foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest expense and other costs arising from this uncertain tax position. SCE&G's current customer rates reflect the availability of domestic production activities deductions. These net deferred costs are expected to be recovered through utility rates following ultimate resolution of the claims. See also Note 5.

Pipeline integrity management costs represent costs incurred to comply with regulatory requirements related to natural gas pipelines located near moderate to high density populations. SCE&G began amortizing $1.9 million of such costs annually in

November 2015.

Various other regulatory assets are expected to be recovered through rates over periods up to 2047.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on SCE&G's financial statements in the period the write-off would be recorded.

3. COMMON EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2016 and December 31, 2015. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were issued and outstanding as of December 30, 2016 and December 31, 2015. All issued and outstanding shares of SCE&G's common and preferred stock are held by SCANA.

SCE&G's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016 and 2015, retained earnings of approximately $79.0 million and $72.4 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

4. LONG-TERM AND SHORT TERM DEBT

Long-term Debt

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2016		2015	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
First Mortgage Bonds (secured)	2018 - 2065	$ 4,840	5.79%	$ 4,340	5.78%
Industrial and Pollution Control Bonds (a)	2028 - 2038	89	3.42%	89	3.42%
Nuclear Fuel Financing	2016	—	—%	100	0.78%
Other	2017 - 2027	26	2.76%	16	2.63%
Total debt		4,955		4,545	
Current maturities of long-term debt		(5)		(104)	
Unamortized premium, net		—		2	
Unamortized debt issuance costs		(35)		(31)	
Total long-term debt, net		$ 4,915		$ 4,412	

(a) Includes variable rate debt of $34.6 million at December 31, 2016 (rate of .76%) and 2015 (rate of .03%) which are hedged by fixed swaps.

On November 1, 2016, Fuel Company paid at maturity $100 million related to a nuclear fuel financing which had an imputed interest rate of 0.78%.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Long-term debt maturities will be $5 million in 2017, $555 million in 2018, $4 million in 2019, $4 million in 2020 and $32 million in 2021.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2016, the Bond Ratio was 5.12.

Lines of Credit (LOC) and Short-Term Borrowings

At December 31, 2016 and 2015, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	2016		2015	
Lines of credit:				
Five-year, expiring December 2020	$	700.0	$	700.0
Fuel Company five-year, expiring December 2020	$	500.0	$	500.0
Three-year, expiring December 2018	$	200.0	$	200.0
Total committed long-term	$	1,400.0	$	1,400.0
Outstanding commercial paper (270 or fewer days)	$	804.3	$	420.2
Weighted average interest rate		1.04%		0.74%
Letters of credit supported by LOC	$	0.3	$	0.3
Available	$	595.4	$	979.5

SCE&G and Fuel Company are parties to credit agreements in the amounts and for the terms described above. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

SCE&G is obligated with respect to an aggregate of $34.6 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

SCE&G participates in a utility money pool with SCANA and another regulated subsidiary of SCANA. Money pool borrowings and investments bear interest at short-term market rates. SCE&G’s interest income and expense from money pool transactions were not significant for any period presented. SCE&G had no outstanding money pool borrowings due to an affiliate for any period presented. At December 31, 2015, SCE&G had money pool investments due from an affiliate of $9.0 million. On SCE&G's balance sheet, amounts due from an affiliate are included within Receivables-affiliated companies.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	2016	2015	2014
Current taxes:			
Federal	$ 49	$ 207	$ 39
State	12	31	(7)
Total current taxes	61	238	32
Deferred tax (benefit) expense, net:			
Federal	162	(9)	151
State	19	(3)	32
Total deferred taxes	181	(12)	183
Investment tax credits:			
Amortization of amounts deferred-state	—	(1)	(1)
Amortization of amounts deferred-federal	(2)	(2)	(3)
Total investment tax credits	(2)	(3)	(4)
Total income tax expense	$ 240	$ 223	$ 211

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2016	2015	2014
Net income	$ 513	$ 466	$ 446
Income tax expense	240	223	211
Total pre-tax income	753	689	657
Income taxes on above at statutory federal income tax rate	264	241	230
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	25	23	20
State investment tax credits (less federal income tax effect)	(5)	(6)	(5)
Allowance for equity funds used during construction	(9)	(9)	(10)
Amortization of federal investment tax credits	(2)	(2)	(2)
Section 41 tax credits	—	1	(3)
Section 45 tax credits	(8)	(9)	(9)
Domestic production activities deduction	(23)	(18)	(7)
Other differences, net	(2)	2	(3)
Total income tax expense	$ 240	$ 223	$ 211

The tax effects of significant temporary differences comprising net deferred tax liability are as follows:

Millions of dollars	**2016**	**2015**
Deferred tax assets:		
Nondeductible accruals	$ 53	$ 52
Asset retirement obligation, including nuclear decommissioning	195	182
Financial instruments	—	2
Unamortized investment tax credits	14	15
Deferred fuel costs	17	7
Other	8	2
Total deferred tax assets	287	260
Deferred tax liabilities:		
Property, plant and equipment	$ 1,753	$ 1,546
Deferred employee benefit plan costs	92	85
Regulatory asset, asset retirement obligation	130	122
Regulatory asset, unrecovered plant	45	49
Demand side management costs	23	23
Prepayments	29	29
Other	49	41
Total deferred tax liabilities	2,121	1,895
Net deferred tax liability	$ 1,834	$ 1,635

SCE&G is included in the consolidated federal income tax returns of SCANA and files various applicable state and local income tax returns. The United States Internal Revenue Service (IRS) has completed examinations of the SCANA’s federal returns through 2004, and the SCANA’s federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2015 as a result of claims discussed below in Changes in Unrecognized Tax Benefits. With few exceptions, SCE&G, is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes in Unrecognized Tax Benefits

Millions of dollars	**2016**	**2015**	**2014**
Unrecognized tax benefits, January 1	$ 49	$ 16	$ 3
Gross increases—uncertain tax positions in prior period	94	33	—
Gross decreases—uncertain tax positions in prior period	—	(2)	—
Gross increases—current period uncertain tax positions	207	2	13
Unrecognized tax benefits, December 31	$ 350	$ 49	$ 16

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under Internal Revenue Code (IRC) Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models.

The IRS examined the claims in the amended returns, and as the examination progressed without resolution, SCE&G evaluated and recorded adjustments to unrecognized tax benefits; however, none of these changes materially affected SCE&G's effective tax rate. In October 2016, the examination of the amended tax returns progressed to the IRS Office of Appeals. In addition, the IRS has begun an examination of SCANA's 2013 through 2015 income tax returns.

These income tax deductions and credits are considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, SCE&G has recorded an unrecognized tax benefit of $350 million ($236 million, net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). If recognized, $17 million of the tax benefit would affect SCE&G's effective tax rate (see discussion below regarding deferral of benefits related to 2015 forward). It is reasonably possible that these unrecognized tax benefits may increase by an additional $292 million within the next 12 months as additional expenditures giving rise to pilot model tax benefits are incurred. It is also reasonably possible that these unrecognized tax benefits may decrease by $49 million within the next 12 months if the claims on the amended returns which are currently in appeals are resolved and that resolution were also applied to the 2013 and 2014 returns. No other material changes in the status of SCE&G's tax positions have occurred through December 31, 2016.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 income tax returns and the expectation of similar claims to be made in determining 2016’s taxable income, SCE&G has recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, and expect that such (net) deferred costs, along with any interest (see below) and other related deferred costs, will be recoverable through customer rates in future years. SCE&G's current customer rates reflect the availability of domestic production activities deductions (see Note 2).

Estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 income tax returns has been deferred and is expected to be recoverable through customer rates in future years. See also Note 2. Otherwise, SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognize tax penalties within other expenses. In 2016, the amount recorded for such interest income is $1.8 million and interest expense is $0.9 million. Such amounts were not significant in 2015 or 2014. No amounts have been recorded for tax penalties for any periods presented.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Derivative instruments are recognized either as assets or liabilities in the statement of financial position and are measured at fair value. Changes in the fair value of derivative instruments are recognized either in earnings, as a component of other comprehensive income (loss) or, for regulated operations, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures, and in some cases risk limits are established to control the level of market, credit, liquidity and operational and administrative risks. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Risk Management Officer and other senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Interest rate swaps may be used to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which swaps designated as cash flow hedges are used to synthetically convert variable rate debt to fixed rate debt, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

Forward starting swap agreements that are designated as cash flow hedges may be used in anticipation of the issuance of debt. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts related to them are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be amortized to interest expense or may be applied as otherwise directed by the SCPSC.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The aggregate notional amounts of the interest rate swaps were as follows:

Millions of dollars	December 31, 2016	December 31, 2015
Not designated as hedging instruments	$ 1,285.0	$ 1,235.0

The following table shows the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the balance sheet, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Fair Values of Derivative Instruments

Millions of dollars	Balance Sheet Location	Asset	Liability
As of December 31, 2016			
Not designated as hedging instruments			
Interest rate contracts			
	Other deferred debits and other assets	$ 71	—
	Derivative financial instruments	—	$ 27
	Other deferred credits and other liabilities	—	3
Total		$ 71	$ 30
As of December 31, 2015			
Not designated as hedging instruments			
Interest rate contracts			
	Other current assets	$ 10	—
	Other deferred debits and other assets	5	—
	Derivative financial instruments	—	$ 33
	Other deferred credits and other liabilities	—	22
Total		$ 15	$ 55

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the statements of income is as follows:

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)	Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount
Year Ended December 31, 2016			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2015			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2014			
Interest rate contracts	$ —	Interest expense	$ (1)

As of December 31, 2016, SCE&G expects during the next 12 months to have no reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Ineffectiveness on interest rate hedges designated as cash flow hedges was insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

Millions of dollars	Loss Deferred in Regulatory Accounts	Gain (Loss) Reclassified from Deferred Accounts into Income Location	Amount
Year Ended December 31, 2016			
Interest rate contracts	$ (34)	Interest Expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2016, SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $2.4 million as an increase to interest expense.

Credit Risk Considerations

Certain derivative contracts contain contingent credit features. These features may include (i) material adverse change clauses or payment acceleration clauses that could result in immediate payments or (ii) the posting of letters of credit or termination of the derivative contract before maturity if specific events occur, such as a credit rating downgrade below investment grade or failure to post collateral.

Derivative Contracts with Credit Contingent Features

Millions of dollars	December 31, 2016	December 31, 2015
in Net Liability Position		
Aggregate fair value of derivatives in net liability position	$ 21.3	$ 47.0
Fair value of collateral already posted	—	3.4
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	21.3	43.6
in Net Asset Position		
Aggregate fair value of derivatives in net asset position	$ 62.0	$ 7.3
Fair value of collateral already posted	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	62.0	7.3

Information related to the offsetting derivative assets follows:

Derivative Assets	Interest Rate Contracts	
Millions of dollars	December 31, 2016	December 31, 2015
Gross Amounts of Recognized Assets	$ 71	$ 15
Gross Amounts Offset in Statement of Financial Position	—	—
Net Amounts Presented in Statement of Financial Position	71	15
Gross Amounts Not Offset - Financial Instruments	(9)	(8)
Gross Amounts Not Offset - Cash Collateral Received	—	—
Net Amount	$ 62	$ 7
Balance sheet location		
Other current assets	—	$ 10
Other deferred debits and other assets	$ 71	5
Total	$ 71	$ 15

Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities	Interest Rate Contracts	
Millions of dollars	December 31, 2016	December 31, 2015
Gross Amounts of Recognized Liabilities	$ 30	$ 55
Gross Amounts Offset in Statement of Financial Position	—	—
Net Amounts Presented in Statement of Financial Position	30	55
Gross Amounts Not Offset - Financial Instruments	(9)	(8)
Gross Amounts Not Offset - Cash Collateral Posted	—	(3)
Net Amount	$ 21	$ 44
Balance sheet location		
Derivative financial instruments	$ 27	$ 33
Other deferred credits and other liabilities	3	22
Total	$ 30	$ 55

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	December 31, 2016	December 31, 2015
Millions of dollars	Level 2	Level 2
Assets:		
Interest rate contracts	$ 71	$ 15
Liabilities:		
Interest rate contracts	$ 30	$ 55

SCE&G had no Level 1 or Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value were as follows:

Long-Term Debt	December 31, 2016		December 31, 2015	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt	$ 4,919.9	$ 5,489.8	$ 4,516.3	$ 4,851.3

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate fair value, and are based on quoted prices from dealers in the commercial paper market. The resulting fair value is considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. SCE&G participates in SCANA's pension plan. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. SCE&G participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumption based on SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2016**	**2015**	**2016**	**2015**
Benefit obligation, January 1	$ 724.0	$ 773.7	$ 191.2	$ 203.2
Service cost	16.9	19.3	3.6	4.3
Interest cost	33.4	32.2	9.7	9.2
Plan participants' contributions	—	—	1.3	1.9
Actuarial (gain) loss	41.8	(47.0)	11.2	(15.4)
Benefits paid	(47.7)	(54.2)	(8.9)	(10.1)
Amounts funded to parent	—	—	(1.6)	(1.9)
Benefit obligation, December 31	$ 768.4	$ 724.0	$ 206.5	$ 191.2

In 2015, based on an evaluation of the mortality experience of the pension plan, a custom mortality table was adopted for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $18.2 million and $1.9 million, respectively, in 2015.

The accumulated benefit obligation for pension benefits was $742.9 million at the end of 2016 and $702.0 million at the end of 2015.The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	**2015**	**2016**	**2015**
Annual discount rate used to determine benefit obligation	4.22%	4.68%	4.30%	4.78%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 6.6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	**2016**	**2015**	**2016**	**2015**
Fair value of plan assets	$ 732.9	$ 720.1	—	—
Benefit obligation	768.4	724.0	$ 206.5	$ 191.2
Funded status	$ (35.5)	$ (3.9)	$ (206.5)	$ (191.2)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Current liability	—	—	$ (10.2)	$ (9.6)
Noncurrent liability	$ (35.5)	$ (3.9)	(196.3)	(181.6)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Net actuarial loss	$ 1.9	$ 2.0	$ 1.0	$ 0.7
Prior service cost	—	—	—	—
Total	$ 1.9	$ 2.0	$ 1.0	$ 0.7

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015
Net actuarial loss	$ 208.8	$ 193.7	$ 28.6	$ 19.9
Prior service cost	2.2	5.2	—	0.2
Total	$ 211.0	$ 198.9	$ 28.6	$ 20.1

In connection with the joint ownership of Summer Station, pension costs attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $23.4 million and $20.3 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $15.8 million and $13.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2016	2015
Fair value of plan assets, January 1	$ 720.1	$ 783.6
Actual return (loss) on plan assets	60.5	(9.3)
Benefits paid	(47.7)	(54.2)
Fair value of plan assets, December 31	$ 732.9	$ 720.1

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. SCANA uses a dynamic investment strategy for the management of the pension plan assets. This strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2016 and 2015 and the target allocation for 2017 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2017**	**2016**	**2015**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	32%
Hedge Funds	9%	11%	11%

For 2017, the expected long-term rate of return on assets will be 7.25%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active and passive returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

*Fair Va*lue Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2016 and 2015, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars		2016		2015
Investments with fair value measure at Level 2:				
Mutual funds	$	115	$	115
Short-term investment vehicles		15		12
US Treasury securities		17		20
Corporate debt securities		76		72
Municipals		13		13
Total assets in the fair value hierarchy		236		232
Investments at net asset value:				
Common collective trust	$	418	$	381
Joint venture interests		79		77
Limited partnership		—		30
Total investments at fair value	$	733	$	720

For all periods presented, assets with fair value measurements classified as Level 1 were insignificant, and there were no assets with fair value measurements classified as Level 3. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2016 or 2015. In addition, in 2015 the fair value of pension plan assets totaling $381 million were previously depicted as mutual funds but have been reclassified as Common collective trust for the current presentation.

Mutual funds held by the plan are open-ended mutual funds registered with the SEC. The price of the mutual funds' shares is based on its NAV, which is determined by dividing the total value of portfolio investments, less any liabilities, by the total number of shares outstanding. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. US Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Common collective trust assets and limited partnerships are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds’ net assets at fair value by the units outstanding at each valuation date. Joint venture interests assets are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and not traded on a daily basis. The valuation of such multi-strategy hedge fund of funds is estimated based on the NAV of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may influence their fair value.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2017	$ 63.1	$ 10.4
2018	65.1	11.0
2019	64.5	11.6
2020	64.7	12.2
2021	67.1	12.8
2022-2026	324.4	69.0

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals at the end of 2023, no significant contributions to the pension plan are expected to be made for the foreseeable future based on current market conditions and assumptions.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2016	2015	2014	2016	2015	2014
Service cost	$ 16.9	$ 19.3	$ 16.0	$ 3.6	$ 4.3	$ 3.6
Interest cost	33.4	32.2	34.1	9.7	9.2	9.2
Expected return on assets	(47.4)	(52.2)	(56.3)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.4	3.5	0.2	0.3	0.3
Amortization of actuarial losses	12.5	11.4	4.0	0.4	1.7	—
Net periodic benefit cost	$ 18.8	$ 14.1	$ 1.3	$ 13.9	$ 15.5	$ 13.1

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in Other Comprehensive Income (OCI), net of tax, were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	—	$ 0.2	$ 0.2	$ 0.3	$ (0.3)	$ 0.4
Amortization of actuarial losses	$ (0.1)	(0.1)	(0.1)	—	—	—
Amortization of prior service cost	—	(0.1)	(0.1)	—	—	—
Total recognized in OCI	$ (0.1)	$ —	$ —	$ 0.3	$ (0.3)	$ 0.4

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 26.3	$ 12.2	$ 87.7	$ 9.0	$ (13.7)	$ 15.5
Amortization of actuarial losses	(11.2)	(10.4)	(3.5)	(0.3)	(1.4)	—
Amortization of prior service cost	(3.0)	(3.1)	(2.8)	(0.2)	(0.3)	(0.2)
Total recognized in regulatory assets	$ 12.1	$ (1.3)	$ 81.4	$ 8.5	$ (15.4)	$ 15.3

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2016	**2015**	**2014**	**2016**	**2015**	**2014**
Discount rate	4.68%	4.20%	5.03%	4.78%	4.30%	5.19%
Expected return on plan assets	7.50%	7.50%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%	3.00%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.00%	7.40%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2021	2020	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2017 are as follows:

	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 12.0	$ 1.0
Prior service cost	1.3	—
Total	$ 13.3	$ 1.0

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCANA sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. SCE&G participates in this plan. Contributions are matched 100% up to 6% of an employee's eligible earnings. Such matching contributions made by the SCE&G totaled $22.9 million in 2016, $21.8 million in 2015 and $20.7 million in 2014. Employee deferrals, matching contributions, and earnings on all contributions are fully vested and nonforfeitable at all times.

9. SHARE-BASED COMPENSATION

SCE&G participates in the SCANA Long-Term Equity Compensation Plan (LTECP) which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2014-2016 performance cycle provides for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 and 2016-2018 awards are based on performance over a single three-year cycle. In the performance cycle for the 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash and 80% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For each of the 2015-2017 and 2016-2018 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of total shareholder return as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. At the Company's discretion, awards under the 2014-2016 performance cycle were paid in cash in February 2017 totaling $20.2 million. Cash-settled liabilities related to earlier performance cycles totaled approximately $13.2 million in 2016, $6.3 million in 2015 and $1.9 million in 2014.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $17.3 million in 2016, $12.2 million in 2015 and $12.6 million in 2014. Such fair value adjustments also resulted in capitalized compensation costs $3.1 million in 2016, $0.6 million in 2015 and $0.6 million in 2014. At December 31, 2016

SCE&G's unrecognized compensation cost, which is expected to be recognized over a weighted -average period of 18 months, was $17.2 million.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under the Price-Anderson Indemnification Act (Price-Anderson), SCE&G (for itself and on behalf of Santee Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the Nuclear Regulatory Commission (NRC) that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at SCE&G's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G’s maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with Nuclear Electric Insurance Limited (NEIL). The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin and up to $2.33 billion resulting from an event of a non-nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of total coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer’s losses. Based on the current annual premium, SCE&G’s portion of the retrospective premium assessment would not exceed $45.8 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with European Mutual Association for Nuclear Insurance (EMANI). The policy provides coverage to Summer Station Unit 1 for property damage and outage costs up to $415 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $1.8 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with a consortium consisting of Westinghouse Electric Company LLC (WEC) and Stone and Webster (Consortium) in 2008 for the design and construction of the New Units. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G’s related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G’s weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Estimated operating costs, including the depreciation of the utility plant costs, are then to be recovered through rates beginning when the construction of each New Unit is completed and placed into service. The BLRA also provides that, in the event of abandonment prior to plant completion, construction work in progress costs incurred, including AFC, and a return on those costs may be recoverable through rates, so long as SCE&G demonstrates by a preponderance of the evidence that its decision to abandon the New Unit(s) was prudent. As of December 31, 2016, SCE&G’s investment in the New Units, including related transmission, totaled $4.5 billion, for which the financing costs on $3.8 billion have been reflected in rates under the BLRA. See Note 2 for a description of rate changes which have occurred under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued Combined Construction and Operating Licenses (COLs) in March 2012. The Consortium has experienced delays throughout much of the project to date, and forecasted work crew efficiency and productivity metrics have not been met. In response, in November 2012, and again in September 2015 and November 2016 (see discussion below), the SCPSC approved SCE&G's requested updates to the milestone schedule, revised contractual substantial completion dates, and increases in capital and other costs. Some of these increased costs were the result of the schedule delays and were the subject of dispute.

October 2015 Amendment and WEC's Engagement of Fluor Corporation (Fluor)

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from Chicago Bridge & Iron Company N.V. (CB&I). Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor as a subcontracted construction manager.

Among other things, the October 2015 Amendment provided SCE&G and Santee Cooper an irrevocable option to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G’s 55% portion being approximately $3.345 billion). This total amount to be paid would be reduced by amounts paid since June 30, 2015. SCE&G, on behalf of itself and as agent for Santee Cooper, executed the fixed price option, subject to SCPSC approval, on July 1, 2016.

The October 2015 Amendment:

(i) resolved by settlement and release most outstanding disputes between SCE&G and the Consortium,

(ii) revised the contractual guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn IRC Section 45J production tax credits (see also below), resulting in escalating liquidated damages that are capped at an aggregate of $338 million per New Unit (SCE&G’s 55% portion being approximately $186 million per New Unit),

(iv) provided for payment to the Consortium of a completion bonus of $150 million per New Unit (SCE&G’s 55% portion being approximately $83 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provided for development of a revised construction milestone payment schedule,

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project,

(vii) provided for an explicit definition of Change in Law designed to reduce the likelihood of certain future commercial disputes, with the Consortium also acknowledging and agreeing that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19, and

(viii) eliminated the requirement or ability of any party to bring suit regarding disputes before substantial completion of the project.

As part of its responsibility as a subcontracted construction manager, Fluor has reviewed and assisted in the development of an updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within the SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits (see below). However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to achieve forecasted productivity and work force efficiency levels.

<u>November 2016 SCPSC Order</u>

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. See also Note 2.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion, including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. The time period to file a Notice of Appeal of the SCPSC's decision with the South Carolina Supreme Court has expired for three of the four non-settling parties, and none of those parties have filed a Notice of Appeal. As for the remaining non-settling party, the time period for that party to file a Notice of Appeal has not yet expired, but as of April 13, 2017 (the filing date of this FERC Form 1 report), that party has not filed a Notice of Appeal.

Construction Milestone Payment Schedule and Related Dispute Resolution Board (DRB) Activity

The October 2015 Amendment established a DRB process for resolving certain commercial claims and disputes. The DRB is comprised of three members chosen by the parties, and amounts in dispute of less than $5 million will be resolved by the DRB without recourse. Amounts in dispute greater than $5 million will be resolved by the DRB for the remainder of the construction of the New Units, with a reserved right to further arbitrate or to litigate such issues at the conclusion of construction.

On December 2, 2016 the DRB issued an order establishing a construction milestone payment schedule (see (v) in October 2015 Amendment above) on which SCE&G and WEC had been unable to agree subsequent to the October 2015 Amendment. The dispute related only to the timing of payments; the total amount to be paid was not in dispute. The DRB order provides that certain subcontractor and other supplier-related costs incurred by the Consortium will be reimbursed by the owners regardless of payment-milestone completion, but that other payments will be made only upon documented achievement of the agreed-upon payment-milestones. Such subcontractor and other supplier-related costs comprised approximately $873 million of the $3.345 billion of fixed option payments that were the subject of the DRB order.

Payment and Performance Obligations and Certain Related Uncertainties

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba Corporation (Toshiba), parent company of WEC, reaffirmed its guaranty of WEC's payment obligations. Additionally, the EPC Contract provides the owners the right, exercisable upon certain conditions, to obtain payment and performance bonds from WEC equal to 15% of the highest projected three months billings during the applicable year, and their aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bonds.

In late 2015, Toshiba's credit ratings declined to below investment grade following disclosures regarding its operating and financial performance and near-term liquidity. As a result, pursuant to the above-described terms of the EPC Contract, SCE&G has obtained standby letters of credit in lieu of payment and performance bonds from WEC totaling $45 million (or approximately $25 million for SCE&G's 55% share). These standby letters of credit expire annually in February, and they automatically renew for successive one-year periods until their final expiration date of August 31, 2020, unless the issuer provides a minimum 60-day notice that it will not renew. If the issuer provides notice that it will not renew, SCE&G may draw upon the standby letter of credit prior to its expiration. In the event that WEC would be unable to meet its payment and performance obligations under the EPC Contract, it is anticipated this funding would provide a source of liquidity to assist in an orderly transition. In addition, the EPC Contract provides that upon the request of SCE&G, and at owners' cost, the Consortium must escrow certain intellectual property and software for the owners' benefit to assist in completion of the New Units. An escrow arrangement has been established, and certain intellectual property and software have been deposited. Additional deposits are anticipated.

In December 2016 through February 2017, Toshiba and WEC announced further deterioration in their financial position and liquidity related to write-downs arising from WEC's acquisition of Stone and Webster from CB&I (discussed above). The announcements noted that WEC and Toshiba have determined that significant losses will be incurred under the EPC Contract for the New Units and under a similar engineering, procurement and construction agreement for other units currently being constructed in the United States. This determination has impacted their allocation of the CB&I purchase price, resulting in recognition of a large amount of goodwill which has in turn been determined to be impaired. Preliminary recognition of this impairment loss (in excess of $6 billion) has left Toshiba with negative shareholders' equity and threatened its liquidity. In January 2017, Toshiba's credit ratings were further reduced. In response, Toshiba has indicated its interest in monetizing portions of its business as it attempts to restructure and restore its financial position. Toshiba has also indicated that it will withdraw from the nuclear construction business prospectively and that it will significantly alter its risk management oversight of its nuclear power business. WEC has told the SCE&G that it and Toshiba are committed to completing the New Units. Toshiba has acknowledged its parental guaranty to the project, but it has informed the SCE&G that no specific commitment regarding completion of the New Units has been agreed to by it so far.

Toshiba also announced that it had requested (and successfully received) a one-month extension of the deadline for submitting its securities report to Japanese securities regulators for the quarter ended December 31, 2016 to allow an internal investigation into the adequacy of internal controls relating to the purchase price allocation process for WEC's acquisition of Stone & Webster and concerns that senior management at WEC may have exerted inappropriate pressure in order to advance the purchase price allocation process. As part of the announcement, it was stated that Toshiba's audit committee was concerned that an invalidation of internal controls (or even the possibility thereof) might affect Toshiba's quarterly financial statements, and that two law firms had been separately retained by the audit committee and WEC to assist with this investigation.

Although progress on the project was seen in December 2016 and January 2017, including the placement of the first of Unit 2's two steam generators, significant risks and uncertainties remain concerning WEC's ability to improve work force efficiency and productivity performance and to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project. In particular, there can be no assurance that their creditors will continue to provide support or that other sources of liquidity will emerge or continue to be available. In the event that WEC were to fail to complete the project in breach of its obligations under the EPC Contract, its payment obligations for damages would increase substantially above the amount of the liquidated damages described above, but would still be subject to limitations.

On March 29, 2017, WEC filed for Chapter 11 bankruptcy protection with the U.S. Bankruptcy Court for the Southern District of New York. In connection with this filing, SCE&G and Santee Cooper (the V.C. Summer Owners) and WEC and Wectec Global Project Services, Inc., (the Debtors) entered into an Interim Assessment Agreement (the Agreement) which expires on April 28, 2017 unless otherwise terminated as outlined in the Agreement. Under the terms of the Agreement, and while it remains in effect, all parties have agreed to continue to perform under the EPC Contract, to indicate in any press release regarding the New Units that the parties have decided to continue the project, and to give the V. C. Summer Owners the right to discuss project status with Fluor and other subcontractors and vendors and to obtain information and documents from them for the project. The V.C. Summer Owners are obligated to pay all costs accrued by the Debtors for Fluor, other subcontractors and vendors for work performed or services rendered while the Agreement remains in effect.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under possible arrangements with other contractors or, were it determined to be prudent, halting the project and leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA.

Finally, additional claims by the Consortium or SCE&G involving the project schedule, budget and performance may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues, and SCE&G expects to resolve disputes through those means. SCE&G expects to seek recovery through rates of any project costs that arise through such dispute resolution processes, as well as other project costs identified from time to time; however, any such request would be subject to the provisions of the November 2016 SCPSC order discussed above. There can be no assurance that recovery would be granted.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction is subject to customary closing conditions, including receipt of necessary regulatory approvals. This transaction will not affect the payment obligations between the parties during construction of the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. SCE&G’s current projected cost for the additional 5% interest being acquired from Santee Cooper is approximately $850 million.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the IRC to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on current tax law and the contractual guaranteed substantial completion dates (and the recently revised forecasted dates of completion) provided above, both New Units would be operational and would qualify for the nuclear production tax credits; however, any further delays in the schedule or changes in tax law could adversely impact these conclusions. See also the Payment and Performance Obligations and Certain Related Uncertainties discussion above. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan remains under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the Clean Air Act, as amended (CAA), Clean Water Act (CWA), Nuclear Waste Act and Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), among others. In many cases, regulations proposed by such authorities could have a significant impact on SCE&G's financial condition, results of operations and cash flows. In addition, SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCE&G continually monitors and evaluates its current and projected emission levels and strives to comply with all state and federal regulations regarding those emissions. SCE&G participates in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also has constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce greenhouse gas (GHG) emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the United States Environmental Protection Agency (EPA) issued a revised standard for new power plants by re-proposing New Source Performance Standards under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per megawatt-hour (MWh) and new natural gas units to meet 1,000 pounds carbon dioxide per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. SCE&G is monitoring the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by

32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives each state from one to three years to issue State Implementation Plans, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. On February 9, 2016, the United States Supreme Court (Supreme Court) stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G or its generation operations. SCE&G expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. The CSAPR replaces the Clean Air Interstate Rule and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual and ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle National Air Ambient Quality Standard. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. The State of South Carolina has chosen to remain in the CSAPR program, even though recent court rulings exempted the state. This allows the state to remain compliant with regional haze standards. Air quality control installations that SCE&G has already completed have positioned it to comply with the existing allowances set by the CSAPR. Any costs incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's Mercury and Air Toxics Standards (MATS) rule containing new standards for mercury and other specified air pollutants became effective. The MATS rule has been the subject of ongoing litigation even while it remains in effect. Rulings on this litigation are not expected to have an impact on SCE&G due to plant retirements, conversions, and enhancements. SCE&G is in compliance with the MATS rule and expects to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The federal effluent limitation guidelines for steam electric generating units (ELG Rule) became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. SCE&G expects that wastewater treatment technology retrofits will be required at Wateree Station. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G is conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications to ensure compliance with this rule. Any costs incurred to comply with this rule are expected to be recoverable through rates.

The EPA's final rule for Coal Combustion Residuals (CCR) became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's coal-fired generating facilities. SCE&G has already closed or has begun the process of closure of all of their ash storage ponds and has previously recognized AROs for such ash storage ponds under existing requirements. SCE&G does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2016, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned Manufactured Gas Plant (MGP) sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by the South Carolina Department of Health and Environmental Control and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2018 and will cost an additional $10.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2016, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $25.7 million and are included in regulatory assets.

Claims and Litigation

SCE&G is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

SCE&G is obligated under various operating leases for land, office space, furniture, vehicles, equipment, rail cars and a purchased power agreement. Leases expire at various dates through 2057.

	Rent Expense		
Millions of dollars	2016	2015	2014
SCE&G	$ 12.1	$ 12.3	$ 12.0

	Future Minimum Rental Payments					
Millions of dollars	2017	2018	2019	2020	2021	Thereafter
SCE&G	$ 25	$ 23	$ 22	$ 1	—	$ 17

Asset Retirement Obligations

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to SCE&G's regulated utility operations. As of December 31, 2016, SCE&G has recorded AROs of approximately $199 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $310 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	2016	2015
Beginning balance	$ 476	$ 521
Liabilities incurred	—	—
Liabilities settled	(11)	(16)
Accretion expense	21	23
Revisions in estimated cash flows	23	(52)
Ending balance	$ 509	$ 476

Revisions in estimated cash flows in 2016 primarily related to changes in projected costs, based on a nuclear decommissioning cost study. Such revisions in 2015 related to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study.

11. AFFILIATED TRANSACTIONS

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's total purchases from this affiliate were $64.5 million in 2016, $94.2 million in 2015 and $120.4 million in 2014. SCE&G's total sales to this affiliate were $64.1 million in 2016, $93.7 million in 2015 and $119.8 million in 2014. The net of the total purchases and total sales are recorded in Other expenses on the consolidated statements of comprehensive income. SCE&G's payable to this affiliate was $4.8 million at December 31, 2016 and insignificant at December 31, 2015. SCE&G's receivable from this affiliate was $4.7 million at December 31, 2016 and insignificant at December 31, 2015.

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy Marketing, Inc. (SCANA Energy) to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $111.5 million in 2016, $128.5 million in 2015 and $195.7 million in 2014. SCE&G's payables to SCANA Energy for such purchases were $8.8 million and $7.5 million as of December 31, 2016 and 2015, respectively.

SCE&G purchases all of the electric generation of A. M. Williams Station, which is owned by GENCO, under a unit power sales agreement. Such unit power purchases, which are included in "Purchased power," totaled approximately $193.9 million and $229.2 million in 2016 and 2015, respectively. SCE&G had approximately $20.2 million and $20.5 million, payable to GENCO for unit power purchases at December 31, 2016 and 2015, respectively.

SCANA Services, Inc. (SCANA Services), on behalf of itself and its parent company, provides the following services to SCE&G, which are rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative services, and retirement benefits. In addition, SCANA Services processes and pays invoices for SCE&G and is reimbursed. Costs for these services, including amounts capitalized, totaled $331.7 million in 2016, $295.5 million in 2015 and $294.9 million in 2014. Amounts expensed are recorded in Other operation and maintenance - nonconsolidated affiliate and Other expenses on the consolidated statements of comprehensive income. SCE&G's payables to SCANA Services for these services were $62.0 million and $56.3 million at December 31, 2016 and 2015, respectively.

Prior to January 31, 2015, Carolina Gas Transmission Corporation (CGT) was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in January 2015.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs are described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution, comprised of the local distribution operations of SCE&G, purchases and sells natural gas, primarily at retail and is regulated by the SCPSC.

Management uses operating income to measure segment profitability for its regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, no allocation is made to segments for interest charges, income tax expense or assets other than utility plant. Intersegment revenue and interest income were not significant. Deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include non-utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense, Expenditures for Assets and Deferred Tax Assets include primarily the amounts that are not allocated to the segments. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs, and totals not allocated to other segments.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2016				
External Revenue	$ 2,619	$ 367	—	$ 2,986
Operating Income	920	56	—	976
Interest Expense	2	—	$ 253	255
Depreciation and Amortization	268	28	—	296
Segment Assets	11,327	825	3,363	15,515
Expenditures for Assets	1,264	78	45	1,387
Deferred Tax Assets	2	n/a	(2)	—
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	837	58	—	895
Interest Expense	2	—	$ 230	232
Depreciation and Amortization	259	28	—	287
Segment Assets	10,274	757	3,151	14,182
Expenditures for Assets	1,080	57	(136)	1,001
Deferred Tax Assets	—	n/a	—	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	730	62	—	792
Interest Expense	1	—	$ 209	210
Depreciation and Amortization	281	27	—	308
Segment Assets	9,547	721	3,203	13,471
Expenditures for Assets	925	55	(57)	923
Deferred Tax Assets	4	n/a	(4)	—

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $236 million and $213 million in 2016 and 2015, respectively (net of capitalized interest of $18 million and $14 million in 2016 and 2015, respectively).

Income taxes paid: $286 million and $87 million in 2016 and 2015, respectively.
Income taxes received: $189 million and $84 million in 2016 and 2015, respectively.

Noncash Investing and Financing Activities:

Accrued construction expenditures: $92 million and $225 million in 2016 and 2015, respectively.

Capital leases expenditures: $14 million and $6 million in 2016 and 2015, respectively.

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2016					
Total operating revenues	$ 717	$ 692	$ 882	$ 695	$ 2,986
Operating income	226	213	350	187	976
Earnings Available to Common Shareholder	113	110	201	89	513
2015					
Total operating revenues	$ 772	$ 709	$ 806	$ 643	$ 2,930
Operating income	227	208	298	162	895
Earnings Available to Common Shareholder	122	107	164	73	466

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	10,374,359,941	8,932,065,915
4	Property Under Capital Leases	21,915,190	20,380,905
5	Plant Purchased or Sold		
6	Completed Construction not Classified	380,645,654	339,731,285
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,776,920,785	9,292,178,105
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	4,808,038,309	4,776,576,438
12	Acquisition Adjustments	31,597,076	31,360,826
13	Total Utility Plant (8 thru 12)	15,616,556,170	14,100,115,369
14	Accum Prov for Depr, Amort, & Depl	4,271,191,389	3,671,697,231
15	Net Utility Plant (13 less 14)	11,345,364,781	10,428,418,138
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,061,334,367	3,592,591,410
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	203,247,204	72,609,983
22	Total In Service (18 thru 21)	4,264,581,571	3,665,201,393
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	6,609,818	6,495,838
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,271,191,389	3,671,697,231

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,066,246,819				376,047,207	3
62,744				1,471,541	4
					5
39,288,690				1,625,679	6
					7
1,105,598,253				379,144,427	8
					9
					10
18,164,518				13,297,353	11
236,250					12
1,123,999,021				392,441,780	13
416,867,984				182,626,174	14
707,131,037				209,815,606	15
					16
					17
406,126,702				62,616,255	18
					19
					20
10,627,302				120,009,919	21
416,754,004				182,626,174	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
113,980					32
416,867,984				182,626,174	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	2,574,132	765,766
3	Nuclear Materials	76,504,565	61,413,516
4	Allowance for Funds Used during Construction	2,082,656	1,522,961
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	81,161,353	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	116,928,535	1,327,653
9	In Reactor (120.3)	223,038,612	685,271
10	SUBTOTAL (Total 8 & 9)	339,967,147	
11	Spent Nuclear Fuel (120.4)	673,993,828	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	786,794,670	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	308,327,658	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	685,271	2,654,627	2
		137,918,081	3
		3,605,617	4
			5
		144,178,325	6
			7
	45,640,963	72,615,225	8
		223,723,883	9
		296,339,108	10
		673,993,828	11
			12
-56,467,219		843,261,889	13
		271,249,372	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 2 Column: e

True-up invoices relating to Batch 25 transferred from Batch 25 In-Process to Batch 25 Stock.

Schedule Page: 202 Line No.: 8 Column: e

Joint Owner Reimbursement	$44,955,692
Batch 25 True-up transferred to In-Reactor	685,271
Total	$45,640,963

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	14,989	
3	(302) Franchises and Consents	13,208,505	
4	(303) Miscellaneous Intangible Plant	64,190,621	15,580,615
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	77,414,115	15,580,615
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,569,330	
9	(311) Structures and Improvements	259,790,982	929,469
10	(312) Boiler Plant Equipment	1,071,739,116	16,292,926
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	429,139,375	9,432,370
13	(315) Accessory Electric Equipment	86,860,626	3,099,729
14	(316) Misc. Power Plant Equipment	31,016,219	937,177
15	(317) Asset Retirement Costs for Steam Production	21,400,999	1,835,498
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,913,516,647	32,527,169
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	880,612	
19	(321) Structures and Improvements	281,071,099	24,961,441
20	(322) Reactor Plant Equipment	506,153,128	15,014,581
21	(323) Turbogenerator Units	110,984,878	5,720,699
22	(324) Accessory Electric Equipment	111,928,066	2,873,135
23	(325) Misc. Power Plant Equipment	110,612,254	43,878,232
24	(326) Asset Retirement Costs for Nuclear Production	8,447,945	14,445,881
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,130,077,982	106,893,969
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	29,436,973	5,992
28	(331) Structures and Improvements	49,551,568	226,058
29	(332) Reservoirs, Dams, and Waterways	444,250,322	338,508
30	(333) Water Wheels, Turbines, and Generators	86,389,764	816,819
31	(334) Accessory Electric Equipment	26,371,855	1,018,194
32	(335) Misc. Power PLant Equipment	9,868,315	660,351
33	(336) Roads, Railroads, and Bridges	1,817,517	
34	(337) Asset Retirement Costs for Hydraulic Production	-40,923	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	647,645,391	3,065,922
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,918,325	
38	(341) Structures and Improvements	41,133,097	601,749
39	(342) Fuel Holders, Products, and Accessories	8,181,023	3,383
40	(343) Prime Movers	583,213,249	4,680,171
41	(344) Generators	94,212,708	46,203
42	(345) Accessory Electric Equipment	61,675,001	1,937,297
43	(346) Misc. Power Plant Equipment	1,786,092	215,122
44	(347) Asset Retirement Costs for Other Production	-6,379,626	913,262
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	786,739,869	8,397,187
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,477,979,889	150,884,247

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			14,989		2
			13,208,505		3
430,611		81,456	79,422,081		4
430,611		81,456	92,645,575		5
					6
					7
8,679			13,560,651		8
2,248,268		-29,091	258,443,092		9
40,043,711		-485,485	1,047,502,846		10
					11
2,211,241		382,988	436,743,492		12
990,683			88,969,672		13
875,788		7,555	31,085,163		14
25,725,227			-2,488,730		15
72,103,597		-124,033	1,873,816,186		16
					17
			880,612		18
50,967			305,981,573		19
4,989,647		-1,651,792	514,526,270		20
1,250,589			115,454,988		21
205,661			114,595,540		22
274,840		1,651,792	155,867,438		23
			22,893,826		24
6,771,704			1,230,200,247		25
					26
3,915		-274	29,438,776		27
52,951			49,724,675		28
349,943			444,238,887		29
238,265			86,968,318		30
3,057,064			24,332,985		31
74,897			10,453,769		32
			1,817,517		33
-40,921		2			34
3,736,114		-272	646,974,927		35
					36
			2,918,325		37
9,402		7,706	41,733,150		38
774,583			7,409,823		39
7,017,441		13,754	580,889,733		40
698,736			93,560,175		41
22,369			63,589,929		42
43,589			1,957,625		43
-125,847			-5,340,517		44
8,440,273		21,460	786,718,243		45
91,051,688		-102,845	4,537,709,603		46

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	83,769,195	1,524,231
49	(352) Structures and Improvements	4,563,204	1,553,709
50	(353) Station Equipment	446,312,291	22,045,819
51	(354) Towers and Fixtures	5,366,642	
52	(355) Poles and Fixtures	358,129,792	31,274,006
53	(356) Overhead Conductors and Devices	210,657,538	9,426,336
54	(357) Underground Conduit	20,724,924	1,199,319
55	(358) Underground Conductors and Devices	62,616,065	-1,180,726
56	(359) Roads and Trails	73,767	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,192,213,418	65,842,694
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	53,677,693	3,205,028
61	(361) Structures and Improvements	4,910,716	
62	(362) Station Equipment	375,387,762	19,992,443
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	435,508,406	27,348,513
65	(365) Overhead Conductors and Devices	478,007,884	18,322,720
66	(366) Underground Conduit	145,349,698	5,352,509
67	(367) Underground Conductors and Devices	430,986,100	20,165,637
68	(368) Line Transformers	453,720,392	17,455,783
69	(369) Services	275,169,193	8,707,818
70	(370) Meters	100,522,891	12,027,342
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	294,849,774	21,507,425
74	(374) Asset Retirement Costs for Distribution Plant	160,586	60,470
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,048,251,095	154,145,688
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,695,915	
87	(390) Structures and Improvements	147,896,423	-243,056
88	(391) Office Furniture and Equipment	11,232,030	3,078,582
89	(392) Transportation Equipment	19,417,920	321,674
90	(393) Stores Equipment	270,242	
91	(394) Tools, Shop and Garage Equipment	3,809,290	82,171
92	(395) Laboratory Equipment	6,277,458	345,104
93	(396) Power Operated Equipment	51,065,026	11,676,392
94	(397) Communication Equipment	7,392,058	323,977
95	(398) Miscellaneous Equipment	5,996,162	559,763
96	SUBTOTAL (Enter Total of lines 86 thru 95)	262,052,524	16,144,607
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	-1,858	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	262,050,666	16,144,607
100	TOTAL (Accounts 101 and 106)	9,057,909,183	402,597,851
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	9,057,909,183	402,597,851

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		-1,037,100	84,256,326		48
		-16,621	6,100,292		49
616,222		-741,863	467,000,025		50
10,582			5,356,060		51
1,328,741		-128,090	387,946,967		52
1,193,895		128,090	219,018,069		53
1,379,428			20,544,815		54
4,202,425			57,232,914		55
			73,767		56
					57
8,731,293		-1,795,584	1,247,529,235		58
					59
		1,037,100	57,919,821		60
9,688			4,901,028		61
1,978,832		775,027	394,176,400		62
					63
4,454,738			458,402,181		64
2,599,204			493,731,400		65
300,113			150,402,094		66
4,931,073			446,220,664		67
3,338,343			467,837,832		68
197,838			283,679,173		69
543,238			112,006,995		70
					71
					72
2,617,785			313,739,414		73
			221,056		74
20,970,852		1,812,127	3,183,238,058		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
11,553		-308,606	8,375,756		86
388,193		-38,285,400	108,979,774		87
596,697			13,713,915		88
1,313,800			18,425,794		89
22,419			247,823		90
79,206			3,812,255		91
295,334			6,327,228		92
5,292,262			57,449,156		93
287,586		-16,544	7,411,905		94
243,897			6,312,028		95
8,530,947		-38,610,550	231,055,634		96
					97
-1,857		1			98
8,529,090		-38,610,549	231,055,634		99
129,713,534		-38,615,395	9,292,178,105		100
					101
					102
					103
129,713,534		-38,615,395	9,292,178,105		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent South Carolina Electric & Gas Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2016/Q4

FOOTNOTE DATA

Schedule Page: 213 Line No.: 1 Column: a

Dominion Carolina Gas Transmission LLC (DCGT) rented office space in a facility that is owned by SCE&G and classified as electric utility plant on the Company's books. DCGT's lease of this facility was terminated as of July 2016. In addition, DCGT rented a field operations building that is owned by SCE&G and was classified as common utility plant on the Company's books at the time. DCGT's lease of this facility was also terminated as of July 2016.

The Company charges a rental fee to Spirit Communications for communication tower site ground leases.

SCANA Services, Inc.(an associated company) utilizes certain assets, including both office space and equipment, that are owned by SCE&G and classified as electric, gas and common utility plant on the Company's books. SCE&G charges SCANA Services a rental fee for such asset usage.

See Transactions with Associated Companies Schedule on page 429 for additional details.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Steam Production	
2	Wateree Waste Water Pond	3,949,494
3	Cope Catalyst	1,223,766
4	Wateree Limestone Ball Mill	1,027,946
5	Wateree Mist Eliminator System	811,095
6	Cope Dual Fuel Firing Systems	752,396
7	Wateree #1 480v MCC & C.H. 4160v	601,311
8	McMeekin #2 Exciter Voltage Regulator	366,141
9	McMeekin #1 Gas Ignitors	365,023
10	Cope 'D' Coal Mill Gearbox	337,629
11	Wateree Spare ESS Transformer	334,748
12	Urquhart #3 4160v Breakers	289,543
13	Urquhart Wastewater System	204,725
14	Minor Steam Production	1,656,271
15	Nuclear Production	
16	VCS #2 & #3 Work Order	4,208,534,114
17	VCS #1 Head Replacement	46,458,145
18	VCS #1 RBCU Industrial Coolers	11,862,166
19	VCS #1 Fukushima Response Strategy	4,790,060
20	VCS #1 Bravo Chiller Replacement	4,499,124
21	VCS #1 Chemical Treatment Equipment	3,730,379
22	VCS #1 SIEM Project	3,680,756
23	VCS #1 Alternate FW Suction Source	3,323,679
24	VCS #1 System Flow Control - CIPP	3,059,553
25	VCS #1 Open Phase Detection System	2,358,646
26	VCS #1 EFW Flow Control Venturi	1,841,342
27	VCS #1 Waste Water Treatment Outfall 005	1,830,595
28	VCS #1 B Loop Aux Crane Replacement	1,491,173
29	VCS #1 Simplex Equipment Replacement	1,391,740
30	VCS #1 License Renewal Project	1,362,187
31	VCS #1 S/R Charlie Chiller Replacement	1,313,302
32	VCS #1 S/R PORV Controls	1,097,081
33	VCS #1 Replace RMWST Heat Tracing	1,054,425
34	VCS #1 Site Drainage Security - Additional	1,038,966
35	VCS #1 PORV Tailpipe Equalizing Line	682,700
36	VCS #1 Waste Water Treatment Outfall 001	545,177
37	VCS #1 DG Exhaust Manifold Replacement	528,625
38	VCS #1 Alpha FWP Turbine Blade Replacement	425,772
39	VCS #1 New Plant Support Building	398,144
40	VCS #1 Control Bldg KWh Meter Replacement	346,566
41	VCS #1 Penstock Piping Project	327,519
42	VCS #1 Additional Protected Area Grounding	280,148
43	TOTAL	4,776,576,438

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	VCS #1 RCCA Tool	203,714
2	Minor Nuclear Production	1,432,511
3	Hydro Production	
4	Saluda Motor Control Ctr & Power Ctr	1,272,034
5	Fairfield Pump 480V MCC & 13.8kV Switchgear	306,288
6	Minor Hydro Production	236,341
7	Other Production	
8	Minor Other Production	360,690
9	Overhead Transmission Lines	
10	Yemassee-Burton 230/115kV	13,671,312
11	Cainhoy 230kV: Foldin #2, Reterm #1	3,799,995
12	Thomas Isl.-Jack Primus 115kV R/W	3,728,121
13	Cain-MP#1:Rebld SPDC & Retap Hamlin	2,045,610
14	AMW - Mt Pleasant #2 Line - Reterm.	1,576,781
15	Toolebeck Transmission 115kV	1,226,498
16	Lyles - Williams Street 115kV Line	1,057,751
17	Faber Place - Hagood 115kV Line #2	732,563
18	#0270B:Thomas Is.-Jack Primus115	672,697
19	McMeekin-Michelin 115kV: Rplc Arrest	593,499
20	Blythewood 115kV Fold In	583,552
21	Williams-Faber Place Replace Strs	510,791
22	NY Wire 115kV Tap-Replace Switches	453,263
23	Burton-St. Hel. Island 115kV G-Line	383,457
24	Queensboro SW Station - Terminate Lines	356,527
25	Summerville-Pepperhill 230kV Line	317,413
26	Yem-McIntosh 115kV: Thermal Uprate	315,707
27	Victory Gardens-Circle Dr. 115kV	265,750
28	AMW-Cainhoy:Rebld SPDC B795	257,837
29	Saluda Hydro Harbison 115 Reterm to LM	236,650
30	Cainhoy-Mt. Pleasant: Install OPGW	224,565
31	Minor Overhead Transmission Lines	750,236
32	Overhead Transmission Lines NND	
33	VCS2-St. George 230kV Line #1 & #2	26,407,944
34	VCS2-LMT 230kV Line #2	24,486,475
35	VCS1-Killian(Winn-Blythwd) 230kV(C)	19,578,429
36	VCS2-St. George 230kV Line #2	18,554,151
37	VCS2-St. George 230kV Line #1 & #2	17,572,801
38	St George-Summerville #1 230kV BLRA	16,681,049
39	Canadys-Sumter 230kV	13,551,823
40	VCS2-St. George 230kV Line #1 & #2	12,064,090
41	VCS1-Killian(Blywd-Killian)230kV(C)	11,845,138
42	VCS1-Killian(WinnJct-Winn)230kV(C)	11,724,656
43	TOTAL	4,776,576,438

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	VCS2-St. George 230kV Line #1 & #2	8,362,206
2	Saluda River-Lyles 230kV BLRA	7,518,682
3	VCS2-St. George 230kV Line #1	6,247,828
4	Denny Terrace-Lyles 230kV	5,262,650
5	Proj 94Q:Saluda Hydro-Newberry 115kV	4,261,765
6	VCS1-Killian 230kV Line: R/W (C)	4,012,716
7	VCS2-St. George 230kV Line #1 & #2	3,246,642
8	VCS2-LMT 230kV Line #1	3,096,108
9	Project #0090N4 Reterm Denny Terrace	2,827,782
10	VCS2-St. George 230kV Line #2	2,359,235
11	VCS1-DT (VCS1-Winn Jct) 230kV	2,144,494
12	VCS2-St. George 230kV Line #1 & #2	1,937,418
13	Parr-Winn 115 #1 Reloc Parr-Switch	1,251,117
14	VCS2-St. George 230kV Line #1 & #2	1,063,392
15	Project 0090M1:Reterm Duke Newport	1,039,732
16	VCS1-Killian(VCS1-WinnJct) 230kV(C)	1,030,935
17	Project #0090N2 Reterm Ward 230kV	951,218
18	McMeekin-Lake Murray Trans. 115kV	873,203
19	Project #0091F: Parr-Midway DC 115	836,049
20	Parr-Denny Terrace 115kV #14 Line	766,230
21	Saluda Hydro-LMT 115 kV	661,877
22	Project #0090N3: Reterm Duke (BR)	491,056
23	Project #0090N6 Temp Energize VCS#2	205,422
24	Overhead Transmission Lines Non BLRA	
25	Dunbar Rd-Orangeburg 115kV	9,364,162
26	St George-Summerville 230kV Line #2	7,982,799
27	VCS-St. George 230kV Line #1	6,756,105
28	VCS2-St.George 1 & 2 Add ROW	1,382,669
29	VCS2-St. George 230kV #1	1,312,736
30	Dunbar Rd.-Orangeburg 115kV	672,267
31	Minor Overhead Transmission Lines Non BLRA	89,631
32	Transmission Substation	
33	Cainhoy 230-115kV Trans. Sub - Cons	9,727,088
34	Blythewood 115kV Sw St - Construct	4,916,097
35	Toolebeck Sw. Station: Construct	4,832,636
36	Summerville Transmission Sub #2071	4,242,784
37	Urquhart Add Switch House	3,536,843
38	Ward - 2nd Autobank & Bus Tie Bkrs	2,844,104
39	Okatie 115kV Sw Station - Construct	2,440,378
40	O'burg East Sub:2 230kV Terms	2,318,568
41	Batesburg Trans. Sub: Add Transfmr	1,675,379
42	Queensboro Transmission Sub #2057	1,437,010
43	TOTAL	4,776,576,438

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Burton Substation - Add 115kV Term.	1,296,079
2	AM Williams Station #2541	854,528
3	Wateree Station 230kV Sub #2531	697,260
4	Saluda Hyd Sub: Ugd 115 Term to SRT	484,000
5	Non-CIP FRAD Replacement	413,162
6	Calhoun County Sub-Relocate SCADA Poles	279,871
7	Denny Terrace Fence Upgrade	246,727
8	CIPv5: 2015 Low Impact Northern Division	225,062
9	Minor Transmission Substation	2,607,647
10	Transmission Substation NND	
11	Saluda River 230/115kV: Construct	12,762,179
12	St. George 230kV Sw Station - Construct	7,428,591
13	Saluda River 230/115kV Sub Site	3,355,688
14	Various 115kV PRCB's: Upgrade	837,434
15	Saluda Hydro Sub: Upgrade 115kV Bus	611,566
16	Various Subs-Upgrd 115kV Bkrs	499,939
17	Killian-Add 1 230kV Terminal-VCS 1	491,498
18	Lake Murray Trans: Add 230kV Term	443,636
19	Parr Steam - Reterminate DT #14	371,767
20	Denny Terrace 230kV Sub. #2045	349,595
21	St.George 230/115kV Sub-Purchase Land	334,044
22	Lyles 230kV Substation #2202	277,778
23	Minor Transmission Substation NND	824,438
24	Distribution Substation	
25	Jack Primus 115-23kV Sub: Construction	1,904,677
26	Sewee Sub.No. 807- Construct	1,044,447
27	Sweetwater 115-12kV Sub: Incr. Capacity	1,015,973
28	Ridgeville 115-46kV - Inst. 22.4MVA	797,605
29	Denmark Ind Pk Sub: Add Transformer	467,422
30	ACS RTU Replacement - 2015	410,706
31	Replac T3111 Bluffton 115-23kV, 28M	378,627
32	Purch Spare 115-23kV, 10.5MVA Transformer	359,373
33	Olar 46-4kv: Convert to 12kV.	268,423
34	Minor Distribution Substation	744,732
35	Customer Substation	
36	Clemson W.T. Sub: Construct 115/23	818,877
37	Minor Customer Substation	127,711
38	Overhead Distribution Lines	
39	Gills Creek Conversion Phase V	353,828
40	Ckt Inspec 2015 Sub 479/CKT 60282	214,302
41	Minor Overhead Distribution Lines	1,366,421
42	UG Distribution Lines	
43	TOTAL	4,776,576,438

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Chas Eastside Station Rebuild	1,672,241
2	The Hotel at Marion Square - UG Service	276,504
3	Pine Hill Sub Exit Feeders 1 & 2	275,752
4	Minor UG Distribution Lines	2,360,399
5	Land and Structures	
6	Install System Prot Training Facility	1,056,972
7	174 King St. Renovations-Charleston	229,926
8	Minor Land and Structures	37,457
9	Transportation & POE	
10	Minor Transportation & POE	217,410
11	Office Furniture and Equipment	
12	Minor Office Furniture and Equipment	66,993
13	Communication Equipment	
14	Replace Entire Radio System	526,594
15	Minor Communication Equipment	11,544
16	Tools & Test Equipment	
17	Admin WO AFUDC Adjustments	-2,352,610
18	Minor Tools & Test Equipment	201,442
19	Intangible Plant	
20	VCS - NFPA 805 Software	16,209,740
21	CHAMPS Replacement	5,277,318
22	Seismic PRA Project	8,080,791
23	Configuration Mgmt. Software	2,257,685
24	Work Management System	1,232,101
25	Cope DCS Software	1,226,625
26	Cope Simulator Software	497,319
27	OSI PI Software	467,542
28	MRule & ER Software	412,600
29	Vegetation Management	301,581
30	AVERT Software	210,667
31	Underground Piping Program	204,594
32	Minor Intangible Plant	485,689
33	Transmission - BLRA-VCS1	
34	VC Summer Sub #2561 - Upgrade PrCB's	8,793,756
35	VCS#1-Upgd 2 Terms & Repl Disc Switch	4,273,687
36	VCS#1-Add Term & Repl 2 Disc Switch	3,844,146
37	VCS1 Upgr 230kV 8902 & 8932	3,344,394
38	VCS1, Bus1: SCPSA Upg 8852 Add 9322	2,973,305
39	Parr Safeguard 115kV	2,699,154
40	VCS1 Add Pineland Terminal fr VCS1	2,195,512
41	VCS1 Upgrade Terminal 8832	1,264,253
42	Project #0090H: VCS #2 Tie to VCS #1	1,093,032
43	TOTAL	4,776,576,438

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Parr 115kV Safeguard - Raise @ VCS	851,870
2	Project #0090J: VCS #2 to VCS #1 Bus #3	762,519
3	VCS3 Tie to VCS1 Bus #1: Bus Tie #1	674,802
4	VCS1, Bus 1: SCPSA repl 8863 & LA's	461,794
5	Payroll Overheads and Adjustments	-256,169
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43	TOTAL	4,776,576,438

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,507,257,793	3,507,257,793		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	222,528,059	222,528,059		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,491,910	3,491,910		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-379,741	-379,741		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	225,640,228	225,640,228		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	126,265,283	126,265,283		
13	Cost of Removal	27,736,544	27,736,544		
14	Salvage (Credit)	2,627,228	2,627,228		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	151,374,599	151,374,599		
16	Other Debit or Cr. Items (Describe, details in footnote):	11,067,988	11,067,988		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,592,591,410	3,592,591,410		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	807,546,643	807,546,643		
21	Nuclear Production	595,592,811	595,592,811		
22	Hydraulic Production-Conventional	302,503,203	302,503,203		
23	Hydraulic Production-Pumped Storage	74,272,616	74,272,616		
24	Other Production	397,855,840	397,855,840		
25	Transmission	347,879,446	347,879,446		
26	Distribution	975,383,660	975,383,660		
27	Regional Transmission and Market Operation				
28	General	91,557,191	91,557,191		
29	TOTAL (Enter Total of lines 20 thru 28)	3,592,591,410	3,592,591,410		

Schedule Page: 219 Line No.: 8 Column: c

Depreciation of Asset Retirement Costs, Distributed Energy Resources property and Cyber Security property recorded as a regulatory asset.

Schedule Page: 219 Line No.: 12 Column: c

Retirements per Page 207, Line 100 column (d)	$129,713,534
Less: Intangible Plant per Page 205, Line 5 column (d)	(430,611)
Capital Lease Asset Reductions Recorded in Accordance with USoA General Instruction No. 20 shown as Plant Retirements	(3,017,640)
Total	$126,265,283

Schedule Page: 219 Line No.: 16 Column: c

ARC retirements reclassified to Regulatory Assets	$ 19,328,763
Gain on Disposal on Vehicles	(154,195)
Book Cost of Land Retired	24,147
Transfers and Adjustments	(8,130,727)
Total	$ 11,067,988

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	APOG, LLC			250
2	Canadys Refined Coal, LLC			659,092
3	Louisa Refined Coal, LLC			276,263
4	Brandon Shores Coaltech, LLC			459,003
5	Brunner Island Refined Coal, LLC			
6	Cope Refined Coal, LLC			
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42	Total Cost of Account 123.1 $ 0		TOTAL	1,394,608

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
		250		1
-1,356,690		718,021		2
-1,367,246		244,529		3
-1,371,246		265,597		4
		1,627,983		5
			1,398,039	6
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-4,095,182		2,856,380	1,398,039	42

Schedule Page: 224 Line No.: 2 Column: g

Amount includes additional investments made during the year of $1,550,574. Also in 2016 $134,955 of assets of Canadys Refined Coal, LLC was distributed to SCE&G and these assets were contributed to Brunner Island Refined Coal, LLC as part of SCE&G's initial investment.

Schedule Page: 224 Line No.: 3 Column: g

Amount includes additional investments made during the year of $1,335,512.

Schedule Page: 224 Line No.: 4 Column: g

Amount includes additional investments made during the year of $1,177,840.

Schedule Page: 224 Line No.: 5 Column: g

Amount is comprised of investments made during the year of $1,493,028. Also in 2016 $134,955 of assets of Canadys Refined Coal, LLC was distributed to SCE&G and these assets were contributed to Brunner Island Refined Coal, LLC as part of SCE&G's initial investment.

Schedule Page: 224 Line No.: 6 Column: h

In 2012, SCE&G sold its 10% interest in Cope Refined Coal, LLC and is being paid for such interest over future periods. This amount reflects such payment received in 2016 and has been recorded in Account 421 - Miscellaneous Nonoperating Income.

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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	57,600,683	46,289,912	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	92,694,189	96,230,379	Electric
8	Transmission Plant (Estimated)	8,078,742	8,440,866	Electric
9	Distribution Plant (Estimated)	26,809,680	29,483,037	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	447,255	367,869	Fleet
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	128,029,866	134,522,151	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	351		
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	185,630,900	180,812,063	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	211,290.20	649,339	45,625.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	569.00		27,845.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	4,294.80	8,759		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	207,564.40	640,580	73,470.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	659.50		659.50	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	659.50			
40	Balance-End of Year			659.50	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	659.50	56		
45	Gains	659.50	56		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2018 No. (f)	2018 Amt. (g)	2019 No. (h)	2019 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
45,625.00		45,625.00		1,186,250.00		1,534,415.20	649,339	1
								2
								3
27,845.00				45,625.00		101,884.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						4,294.80	8,759	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
73,470.00		45,625.00		1,231,875.00		1,632,004.40	640,580	29
								30
								31
								32
								33
								34
								35
659.50		659.50		32,315.50		34,953.50		36
				1,319.00		1,319.00		37
								38
				659.50		1,319.00		39
659.50		659.50		32,975.00		34,953.50		40
								41
								42
								43
				659.50	18	1,319.00	74	44
				659.50	18	1,319.00	74	45
								46

Schedule Page: 228 Line No.: 4 Column: d

Vintage 2017 allowances allocated by the EPA for the CSAPR SO2 Group 2 program.

Schedule Page: 228 Line No.: 4 Column: f

Vintage 2018 allowances allocated by the EPA for the CSAPR SO2 Group 2 program.

Schedule Page: 228 Line No.: 4 Column: j

Vintage 2046 allowances allocated by the EPA for the SO2 Acid Rain program.

Schedule Page: 228 Line No.: 18 Column: m

Allowances Inventory charged to account 509 - Allowances does not agree to page 320, line 12 column (b) due to the recognition, upon termination of the CAIR program, of previously realized gains from the sale of NOX emission allowances previously deferred in Account 254 - Other Regulatory Liabilities.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	40,331.80	6,804		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	120.20		8,817.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	GENCO- Associated Company	495.00			
10					
11					
12					
13					
14					
15	Total	495.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	26,819.30	6,804		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	14,127.70		8,817.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2018		2019		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						40,331.80	6,804	1
								2
								3
8,817.00						17,754.20		4
								5
								6
								7
								8
						495.00		9
								10
								11
								12
								13
								14
						495.00		15
								16
								17
						26,819.30	6,804	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
8,817.00						31,761.70		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 4 Column: b

Vintage 2016 New Unit Set Aside Allowances allocated by the EPA for the CSAPR Nox Ozone Season program.

Schedule Page: 229 Line No.: 4 Column: d

Vintage 2017 New Unit Set Aside allowances allocated by the EPA for the CSAPR Nox Annual program.

Schedule Page: 229 Line No.: 4 Column: f

Vintage 2018 allowances allocated by the EPA for the CSAPR Nox Annual program.

Schedule Page: 229 Line No.: 18 Column: m

Allowances Inventory charged to account 509 - Allowances does not agree to page 320, line 12 column (b) due to the recognition, upon termination of the CAIR program, of previously realized gains from the sale of NOX emission allowances previously deferred in Account 254 - Other Regulatory Liabilities.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant:					
22						
23	Unrecovered Plant related to the					
24	retirement of Canadys Unit No. 1					
25	SCPSC authorization received					
26	12/2012. (Docket No. 2012-218-E,					
27	Order 2012-951) Amortization					
28	over approximately 14 years					
29	beginning 1/2013.	19,761,879		407	1,607,593	13,331,507
30						
31	Unrecovered Plant related to the					
32	retirement of Canadys Unit No. 2					
33	and Unit No. 3. SCPSC					
34	authorization received 9/2013.					
35	(Docket No. 2013-276-E, Order					
36	2013-649) Amortization over					
37	approximately 12 years beginning					
38	1/2014.	141,056,111	4,755,494	407	12,270,624	103,221,687
39						
40	Unrecovered Plant associated with					
41	early retirement of coal					
42	equipment at Urquhart Unit No. 3.	557,755				557,755
43						
44	Unrecovered Plant associated with					
45	early retirement of coal					
46	equipment at McMeekin Station.	1,427,729	1,005,199			1,427,729
47						
48						
49	TOTAL	162,803,474	5,760,693		13,878,217	118,538,678

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Rainbow Energy -				
3	System Impact Study	5,071	408.1/561.6/926	15,000	253
4					
5	Rainbow Energy -				
6	System Impact Study	3,908	408.1/561.6/926	15,000	253
7					
8	Rainbow Energy -				
9	Facilities Study	333	408.1/561.6/926	3,600	253
10					
11	Santee Cooper Longpoint -				
12	Facilities Study	139	408.1/561.6/926		
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23	20151013004 System Impact Study	3,127	408.1/561.7/926		
24	20151216001 System Impact Study	5,033	408.1/561.7/926	40,000	253
25	20160208001 Facilities Study	1,482	408.1/561.7/926	35,600	253
26	20160810001 Facilities Study			32,500	253
27	20160810001 System Impact Study	3,034	408.1/561.7/926	50,000	253
28	20150612001 Facilities Study	2,871	408.1/561.7/926		
29	20150608003 Facilities Study	1,257	408.1/561.7/926		
30	20160805001 Supplemental Review	1,021	408.1/561.7/926	1,800	253
31	20151105001 System Impact Study	1,523	408.1/561.7/926		
32	20151028002 Facilities Study	373	408.1/561.7/926	3,000	253
33	20151028002 System Impact Study	1,496	408.1/561.7/926		
34	20160328001 Facilities Study	359	408.1/561.7/926		
35	20160328001 System Impact Study	2,226	408.1/561.7/926	11,000	253
36	20151210001 Feasibility Study	2,056	408.1/561.7/926	1,000	253
37	20160811001 System Impact Study	1,429	408.1/561.7/926	20,000	253
38	20150928001 System Impact Study	1,496	408.1/561.7/926		
39	20150812001 Facilities Study	165	408.1/561.7/926		
40	20150812002 System Impact Study	1,005	408.1/561.7/926		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20150812003 Facilities Study	1,082	408.1/561.7/926		
23	20150812002 Facilities Study	980	408.1/561.7/926		
24	20150918001 Facilities Study	747	408.1/561.7/926	4,700	253
25	20151223001 System Impact Study	1,786	408.1/561.7/926	2,800	253
26	20151014001 System Impact Study	902	408.1/561.7/926	2,000	253
27	20151028001 Facilities Study	1,667	408.1/561.7/926	100,000	253
28	20151028001 System Impact Study	5,396	408.1/561.7/926		
29	20150623001 System Impact Study	4,036	408.1/561.7/926		
30	20151105002 System Impact Study	1,056	408.1/561.7/926		
31	20151125001 System Impact Study	1,124	408.1/561.7/926	2,800	253
32	20160212001 System Impact Study	1,912	408.1/561.7/926	4,500	253
33	20150623001 Facilities Study	1,884	408.1/561.7/926	100,000	253
34	20151125001 Facilities Study	887	408.1/561.7/926	3,500	253
35	20151013003 System Impact Study	2,364	408.1/561.7/926		
36	20150706002 Facilities Study	1,874	408.1/561.7/926		
37	20150730002 Facilities Study	1,309	408.1/561.7/926		
38	20150730001 Facilities Study	902	408.1/561.7/926		
39	20151124001 System Impact Study	1,087	408.1/561.7/926		
40	20151124002 System Impact Study	902	408.1/561.7/926		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20150615001 Facilities Study	2,369	408.1/561.7/926		
23	20150608002 Facilities Study	688	408.1/561.7/926		
24	20150831001 Facilities Study	1,715	408.1/561.7/926		
25	20151013002 Facilities Study	1,495	408.1/561.7/926		
26	20151013003 Facilities Study	1,184	408.1/561.7/926		
27	20151013001 Facilities Study	975	408.1/561.7/926		
28	20151124001 Facilities Study	1,011	408.1/561.7/926	4,500	253
29	20151124002 Facilities Study	1,301	408.1/561.7/926	3,000	253
30	20160927001 System Impact Study	234	408.1/561.7/926	20,200	253
31	20161027002 System Impact Study			13,600	253
32	20161027002 Facilities Study			15,010	253
33	20151112001 System Impact Study	1,493	408.1/561.7/926	2,800	253
34	20151230001 System Impact Study	1,709	408.1/561.7/926	2,000	253
35	20151230002 System Impact Study	1,417	408.1/561.7/926	2,000	253
36	20151106002 Facilities Study	469	408.1/561.7/926	4,500	253
37	20160105001 Facilities Study	2,464	408.1/561.7/926	17,200	253
38	20160725001 Supplemental Review			2,100	253
39	20151106002 System Impact Study	915	408.1/561.7/926		
40	20150608002 Facilities Study	625	408.1/561.7/926	22,800	253

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	20161006001 System Impact Study			26,271	253
23	20160805002 Supplemental Review	1,021	408.1/561.7/926	1,800	253
24	20150423001 Facilities Study	2,382	408.1/561.7/926		
25	20160803001 System Impact Study	2,520	408.1/561.7/926	82,500	253
26	20160721001 Supplemental Review	2,100	408.1/561.7/926	3,750	253
27	20150629001 Facilities Study	109	408.1/561.7/926		
28	20150930001 System Impact Study	601	408.1/561.7/926		
29	20150706001 Facilities Study	4,073	408.1/561.7/926		
30	20150713001 Facilities Study	51	408.1/561.7/926	5,250	253
31	20151106003 System Impact Study	1,281	408.1/561.7/926	1,800	253
32	20160707001 Facilities Study	513	408.1/561.7/926	10,482	253
33	20150623002 Facilities Study	60	408.1/561.7/926		
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 3 Column: d

Represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to expense as the actual charges are incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Schedule Page: 231 Line No.: 6 Column: d

Represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to expense as the actual charges are incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Schedule Page: 231 Line No.: 9 Column: d

Represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to expense as the actual charges are incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Schedule Page: 231 Line No.: 22 Column: d

Column (d) represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to expense as the actual charges are incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Income Taxes	275,729,600	25,938,400	282	8,612,800	293,055,200
2	Columbia & Charleston Franchise	21,669,711		407	4,183,224	17,486,487
3	Gas Water Heater Rebate Program (2011-2021)	4,598,419	2,542,896	912	1,842,125	5,299,190
4	Decommissioning Asset Ret. Obligation	51,793,945	23,050,165	Various	25,609,115	49,234,995
5	MGP Environmental Remediation	34,815,047	94,092,471	735	103,210,753	25,696,765
6	Deferred ARO Accretion & Depreciation Costs	318,225,828	34,827,349	Various	14,315,880	338,737,297
7	Interest Rate Derivatives	525,958,158	253,590,943	244/427	168,108,545	611,440,556
8	Deferred Employee Benefit Plan Costs-Gas (ASC 715)	29,595,698	30,181,441	Various	29,690,306	30,086,833
9	Deferred Employee Benefit Plan Costs-Elec (ASC 715)	190,915,766	212,400,407	Various	191,639,510	211,676,663
10	Gas Customer Awareness Program (11/2011-10/2018)	548,681	603	913	335,707	213,577
11	Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	4,873,967		530	183,816	4,690,151
12	Deferred Capacity Charges (7/2010-7/2020)	1,344,334		555	296,000	1,048,334
13	Deferred Capacity Charges	2,097,311	37,200			2,134,511
14	Electric Demand Side Management	66,102,359	19,435,179	254/908	21,173,780	64,363,758
15	Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	8,226,259		555	282,660	7,943,599
16	Economic Development Grants (10/2009-11/2031)	5,393,311	10,376,170	921	1,033,738	14,735,743
17	Major Maintenance Accrual and Interest	5,636,230	14,562,139	Various	9,049,480	11,148,889
18	Deferred Pension Cost - Gas (11/2013-1/2027)	11,396,113		926	1,029,508	10,366,605
19	Deferred Pension Cost - Electric (1/2013-12/2042)	56,689,427		926	1,987,835	54,701,592
20	Environmental Compliance Studies (7/2010 - 7/2020)	430,472		506	94,782	335,690
21	Deferred Pollution Control Costs -					
22	Wateree (1/2013-9/2040)	26,217,896		407.3	1,061,940	25,155,956
23	Research and Development Grant (1/2013-12/2047)	3,200,000		930.2	100,000	3,100,000
24	Environmental Remediation Cost	365,099	3,056,173	Various	3,292,485	128,787
25	Amount Undercollected - Gas Cost Adjustment	7,019,370	70,542,815	Various	63,310,161	14,252,024
26	Gas WNA Cap - Winter 2015 (11/2016 - 10/2021)	1,194,644	968,520	480/481	72,105	2,091,059
27	Gas WNA Cap - Winter 2016		914,938			914,938
28	Fukushima Compliance Costs	3,665,646	1,662,106	Various	1,234,222	4,093,530
29	Undercollected Electric Pension Expense	5,997,929	14,959,319	926	19,598,798	1,358,450
30	Deferred Long-Term Capacity Contract	8,730,837	17,000,883	555/565	10,800,000	14,931,720
31	Carrying Costs Accrual	18,232,429	13,970,853			32,203,282
32	Cyber Compliance Costs	994,388	2,748,822			3,743,210
33	CIPv5 Compliance Costs	2,367,253	4,568,249			6,935,502
34	Gas Pipeline Integrity Costs	3,723,778	4,114,293	887	1,881,142	5,956,929
35	DER and NET Metering Costs	731,511	3,143,274	Various	4,901,025	-1,026,240
36	Coal Supply Contract Termination (5/2015-12/2016)	1,200,000		501	1,200,000	
37	Nuclear Refueling Outage Costs	3,903,725		524/528	3,903,725	
38	Deferred Costs Related to Certain Claims					
39	for Tax Deductions and Credits		15,337,175			15,337,175
40	Deferred Storm Damage Costs		19,706,491			19,706,491
41						
42						
43						
44	**TOTAL :**	1,703,585,141	893,729,274		694,035,167	1,903,279,248

Schedule Page: 232 Line No.: 2 Column: a

SCPSC Docket No. 2002-223-E

Amounts are being amortized through cost of service rates over approximately twenty years.

Schedule Page: 232 Line No.: 3 Column: a

SCPSC Docket No. 89-245-G
SCPSC Docket No. 2008-155-G

Schedule Page: 232 Line No.: 4 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 5 Column: a

SCPSC Docket No. 2005-113-G

Schedule Page: 232 Line No.: 6 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 7 Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

Schedule Page: 232 Line No.: 10 Column: a

SCPSC Docket No. 2007-418-G

Schedule Page: 232 Line No.: 11 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 12 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 13 Column: a

SCPSC Docket No. 2008-230-E

Schedule Page: 232 Line No.: 14 Column: a

Amortization of deferred balance is a function of customer usage per a Rate Rider mechanism approved by the SCPSC in Docket Nos. 2013-50-E, 2013-208-E, 2014-44-E, 2015-45-E and 2016-40-E.

Schedule Page: 232 Line No.: 15 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 16 Column: a

SCPSC Docket No. 2009-497-E
SCPSC Docket No. 2011-264-E
SCPSC Docket No. 2012-246-E

Schedule Page: 232 Line No.: 17 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 18 Column: a

SCPSC Docket No. 2009-35-G
SCPSC Docket No. 2013-6-G

Schedule Page: 232 Line No.: 19 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 20 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 22 Column: a

SCPSC Docket No. 2008-393-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 23 Column: a

SCPSC Docket No. 2011-513-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 24 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 25 Column: a

SCPSC Docket No. 2016-6-G

Per SCPSC Docket No. 2005-5-G, commodity and demand components of purchased gas cost are recovered separately. Balances for these components as of December 31, 2016 are as follows:

Commodity	$ 4,630,213
Demand	9,621,811
Total	$14,252,024

Schedule Page: 232 Line No.: 26 Column: a

SCPSC Docket No. 2016-6-G

Schedule Page: 232 Line No.: 28 Column: a

SCPSC Docket No. 2012-277-E

Schedule Page: 232 Line No.: 29 Column: a

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2014-88-E
SCPSC Docket No. 2016-103-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

Schedule Page: 232 Line No.: 30 Column: a

SCPSC Docket No. 2013-276-E

In the docket referenced above, the SCPSC authorized amortization in the amount of $10.8 million annually. Such amortization will remain in effect until the deferred balance is fully amortized.

Schedule Page: 232 Line No.: 31 Column: a

In SCPSC Docket No. 2013-336-E, the SCPSC approved the exclusion from rate base of ADIT assets associated with the treatment of interest capitalized for tax purposes related to new nuclear construction. The SCPSC also approved the accrual of carrying costs on the balance of the ADIT assets removed from rate base, with such carrying costs being deferred as a regulatory asset.

Schedule Page: 232 Line No.: 32 Column: a

SCPSC Docket No. 2015-372-E

Schedule Page: 232 Line No.: 33 Column: a

SCPSC Docket No. 2014-416-E

Schedule Page: 232 Line No.: 34 Column: a

SCPSC Docket No. 2014-461-G

In the docket referenced above, the SCPSC authorized amortization in a levelized annual amount of $1,881,143 beginning in November 2015.

Schedule Page: 232 Line No.: 35 Column: a

SCPSC Docket No. 2014-246-E
SCPSC Docket No. 2015-54-E
SCPSC Docket No. 2016-2-E

Schedule Page: 232 Line No.: 37 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 39 Column: a

SCPSC Docket No. 2016-373-E

Schedule Page: 232 Line No.: 40 Column: a

SCPSC Docket No. 2012-218-E

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Noncurrent Receivable - Post					
2	Retirement Benefits	34,101,368	27,973,631	Various	22,859,427	39,215,572
3	Charleston Garage Revenue Bond					
4	Long-Term	1,612,061	47,752	143	1,249,500	410,313
5	5 year Commitment Fees	5,369,844	1,817	427	1,371,781	3,999,880
6	3 Year Commitment Fees	294,529		427	153,667	140,862
7	Progress Payments/Plant Equipmt	4,694,777	16,980,975	Various	13,868,006	7,807,746
8	Director's Endowment	382,447	24,466	426.5	27,389	379,524
9	Pole Attachment Receivables	2,193,680	4,498,537	143/589	4,506,585	2,185,632
10	Long Term Power Plant Service					
11	Agreement (2007-2021)	1,311,576	16,724,672	107/553	16,613,718	1,422,530
12	Lease Buyout Costs (2009-2057)	5,273,501		Various	194,249	5,079,252
13	Department of Energy Nuclear					
14	Loan Guarantee Application					
15	Fee	1,183,076				1,183,076
16	Workers' Comp Reserve	397,772	4,635	925	25,779	376,628
17	NND Transmission Lines	90,000		107	90,000	
18	Multi-year Cloud Computing					
19	Fees (2014-2017)	130,030		912	104,024	26,006
20	McMeekin Solar Study	116,552		923	116,552	
21	Income Tax Receivable -					
22	Amended Returns		72,124,423			72,124,423
23	Other	-6,983	30,188,579	Various	30,761,374	-579,778
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47	Misc. Work in Progress	27,490,688				31,470,149
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	84,634,918				165,241,815

Schedule Page: 233 Line No.: 23 Column: f

Credit balance due primarily to CIAC awaiting distribution and clearance to capital work order(s).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Regulatory Asset - Asset Retirement Obligation	140,717,394	143,551,826
3	Other Post Employment Benefits	58,815,900	62,870,700
4	Unamortized Investment Tax Credits	13,633,600	12,841,000
5	Storm Damage	1,492,000	-7,537,800
6	Nuclear Refueling Costs	-1,493,100	4,466,400
7	Other	8,463,300	8,166,500
8	TOTAL Electric (Enter Total of lines 2 thru 7)	221,629,094	224,358,626
9	Gas		
10	Regulatory Asset - Asset Retirement Obligation	7,950,100	10,247,700
11	Other Post Employment Benefits	8,664,800	9,155,000
12	Environmental Remediation	-6,383,900	-6,195,000
13	Incentive Compensation	4,134,000	4,131,300
14	Unamortized Investment Tax Credits	973,000	903,300
15	Other	2,450,700	2,148,200
16	TOTAL Gas (Enter Total of lines 10 thru 15	17,788,700	20,390,500
17	Other (Specify): Non Operating	36,607,402	44,397,878
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	276,025,196	289,147,004

Notes

Line 7 "Other":

	Balance at Beg. of Year	Balance at End of Year
Major Maintenance	(2,155,800)	(4,267,700)
Early Retirement Programs	3,492,800	2,904,400
Reserve for Injuries and Damages	1,924,800	2,655,000
Nuclear Fuel	(1,307,100)	2,411,500
Vacation Accrual	1,909,400	1,701,300
Uncollectible Accounts	929,300	1,069,500
Incentive Compensation	888,500	894,500
Long Term Disability	308,100	256,800
Regulatory Asset/Liability, Interest Rate Derivatives	1,984,900	-
All Other	488,400	541,200
Total	$ 8,463,300	$ 8,166,500

Line 15 "Other":

	Balance at Beg. of Year	Balance at End of Year
Inventory Capitalization under 236A	$ 611,600	$ 563,800
Early Retirement Programs	628,100	470,600
Reserve for Injuries and Damages	123,400	351,300
Vacation Accrual	337,700	301,100
Uncollectible Accounts	204,500	169,700
Long Term Disability	353,000	99,400
All Other	192,400	192,300
Total	$ 2,450,700	$ 2,148,200

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line 17 "Other":

	Balance at Beg. of Year	Balance at End of Year
Regulatory Asset - Asset Retirement Obligation	$33,488,202	$41,058,978
Directors' Endowment	1,195,800	1,244,900
Early Retirement Programs	876,400	840,200
Other Post Employee Benefits	428,100	621,300
All Other	618,900	632,500
Total	$36,607,402	$44,397,878

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock Issued	50,000,000		
3	Total Common	50,000,000		
4				
5				
6	Account 204:			
7	Preferred Stock Issued	20,000,000		
8	Total Preferred	20,000,000		
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
40,296,147	576,405,122					2
40,296,147	576,405,122					3
						4
						5
						6
1,000	100,000					7
1,000	100,000					8
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Schedule Page: 250 Line No.: 2 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: e

These shares are held by SCANA Corporation and do not pay a dividend.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received from Stockholders:	
2	Cash donations by former parent company, General Gas & Electric	
3	Corporation	240,000
4	Equity advance from SCANA to SCE&G from issuance of 2.3 million	
5	shares of common stock (1992)	89,941,500
6	Equity advance from SCANA to SCE&G from issuance of 404,222 shares	
7	of SCANA common stock under the Dividend Reinvestment and Stock	
8	Purchase Plan and 422,082 shares of SCANA common stock under the	
9	Stock Purchase Savings Plan (1992)	36,895,774
10	Equity advance from SCANA to SCE&G from issuance of 529,954 shares	
11	of SCANA common stock under the Dividend Reinvestment and Stock	
12	Purchase Plan and 705,498 shares of SCANA Common Stock under	
13	the Stock Purchase Saving Plan (1993)	58,141,500
14	Equity advance from SCANA to SCE&G from issuance of 595,438 shares	
15	of SCANA common stock under the Dividend Reinvestment and Stock	
16	Purchase Plan and 781,354 shares of SCANA common stock	
17	under the Stock Purchase Savings Plan (1994)	43,425,899
18	Equity advance from SCANA to SCE&G from issuance of 1,434,664	
19	shares of SCANA common stock under the SCANA Investor Plus Plan	
20	and 1,630,993 shares of SCANA common stock under the Stock	
21	Purchase Savings Plan (1996)	53,658,065
22	Equity advance from SCANA to SCE&G from issuance of 4.5 million	
23	shares of SCANA common stock (1995)	85,845,000
24	Equity advance from SCANA to SCE&G from issuance of 1,118,366	
25	shares of SCANA common stock under the SCANA Investor Plus Plan	
26	and 1,393,761 shares of SCANA common stock under the	
27	Stock Purchase Savings Plan (1996)	49,141,871
28	Equity advance from SCANA to SCE&G from issuance of 170,524 shares	
29	of SCANA common stock under the SCANA Investor Plus Plan and	
30	the issuance of 342,409 shares of SCANA common stock under	
31	the Stock Purchase Savings Plan (1997)	12,147,617
32	Reclass of 2001-2003 Capital Contributions from Parent from 211	
33	account "Misc Paid-In Capital"	197,911,200
34	Repayment of Capital Contributions from Parent (2004)	-3,206,660
35	Equity advance from SCANA to SCE&G from issuance of 356,008 shares	
36	of SCANA common stock under the SCANA Investor Plus Plan and	
37	the issuance of 780,472 shares of SCANA common stock under the	
38	Stock Purchase Savings Plan (2004)	41,728,531
39		
40	TOTAL	2,288,167,716

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Reclass of 2005 Capital Contributions from Parent from	
2	account 211 "Misc. Paid in Capital."	4,591,300
3	Equity advance from SCANA to SCE&G from issuance of SCANA common	
4	stock under the SCANA Investor Plus Plan and the Stock Purchase	
5	Saving Plan (2005)	34,697,793
6	Equity advance from SCANA to SCE&G based on SCE&G's funding	
7	requirements	1,394,496,916
8	Income tax benefit true-up	78,259,588
9	Equity advance from SCANA to SCE&G from issuance of SCANA Common	
10	stock	100,500,000
11	Subtotal - Account 208	2,278,415,894
12		
13	Account 209 - Reduction in Par or stated value of Capital Stock	
14	Subtotal - Account 209	
15		
16	Account 210 - Gain on Resale or Cancellation of Reacquired Capital	
17	Stock	
18	Subtotal - Account 210	
19		
20	Account 211 - Miscellaneous Paid - In - Capital:	
21	Merger of Florence Gas Division	6,284,464
22	Revaluation of fixed capital and related depreciation reserves	
23	(1940)	8,547,035
24	Merger of Lexington Water Power Company (1943)	5,418,114
25	Reserves for amounts in excess of original cost of utility plant	
26	(1943)	-9,547,035
27	Discount on purchase of 20 shares of 5% series, $50 par value	
28	preferred stock (1944)	100
29	Revaluation of Florence-Darlington gas properties (1944)	-276,426
30	Disposition of electric and common plant adjustments (1945)	39,140
31	Disposition of other physical property adjustments (1945)	82,567
32	Disposition of gas plant intangibles (1945)	-644,761
33	Adjustments of 1941 land sales by Lexington Water Power	
34	Company (1949)	12,331
35	Funds received from Script Agent under 1946 Plan for Stock	
36	Distribution by former Parent Company (1952, 1953)	98,308
37	Capital Contributions from Parent (2001)	32,908,300
38	Capital Contributions from Parent (2002)	156,780,200
39	Capital Contributions from Parent (2003)	8,222,700
40	TOTAL	2,288,167,716

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Reclass of 2001-2003 Capital Contributions from Parent to	
2	account 208 "Donations Received from Stockholders" (2004)	-197,911,200
3	Other	-262,015
4	Equity advance representing the true up of the benefit allocation	
5	relating to the SCANA tax benefit	4,591,300
6	Reclass of 2005 Capital Contributions from Parent to	
7	account 208 "Donations Received from Stockholders."	-4,591,300
8	Subtotal - Account 211	9,751,822
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40	TOTAL	2,288,167,716

Schedule Page: 253.1 Line No.: 7 Column: b

During 2016, the Company received equity advances from SCANA in the amount of $100,000,000. The entry was:

Account	Debit	Credit
131 - Cash	$100,000,000	
208 - Donations Received from Stockholders		$100,000,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense, no par value	4,335,379
2		
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21		
22	TOTAL	4,335,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2			
3	First Mortgage Bonds:		
4	6.625% Series, due 2032	300,000,000	2,928,187
5			2,397,000 D
6			
7	4.50% Series, due 2064	300,000,000	3,244,190
8			3,186,000 D
9	4.50% Series due 2064 (State Commission Order Nos. 2010-660 issued on 03-30-2010		
10	and 2013-277 Issued on 05-09-2013)	75,000,000	656,250
11			1,617,750 D
12			
13	5.25% Series, due 2035	100,000,000	1,032,840
14			1,821,000 D
15			
16	5.30% Series, due 2033	300,000,000	2,678,847
17			579,000 D
18			
19	5.25% Series, due 2018	250,000,000	2,443,883
20			615,000 D
21			
22	5.80% Series, due 2033	200,000,000	1,785,478
23			646,000 D
24			
25	6.25% Series, due 2036	125,000,000	1,240,777
26			421,250 D
27			
28	6.05% Series, due 2038	250,000,000	2,611,037
29			242,500 D
30			
31	6.05% Series, due 2038	110,000,000	962,500
32			5,365,800 D
33	TOTAL	5,029,541,381	52,302,580

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
01-31-2002	02-01-2032	01-31-2002	02-01-2032	300,000,000	19,875,000	4
						5
						6
06-01-2014	06-01-2064	06-01-2014	06-01-2064	300,000,000	13,500,000	7
						8
						9
06-13-2016	06-01-2064	06-13-2016	06-01-2064	75,000,000	1,856,250	10
						11
						12
03-08-2005	03-01-2035	03-08-2005	03-01-2035	100,000,000	5,250,000	13
						14
						15
05-21-2003	05-15-2033	05-21-2003	05-15-2033	300,000,000	15,900,000	16
						17
						18
11-06-2003	11-01-2018	11-06-2003	11-01-2018	250,000,000	13,125,000	19
						20
						21
01-23-2003	01-15-2033	01-23-2003	01-15-2033	200,000,000	11,600,000	22
						23
						24
06-27-2006	07-01-2036	06-27-2006	07-01-2036	125,000,000	7,812,500	25
						26
						27
01-14-2008	01-15-2038	01-14-2008	01-15-2038	250,000,000	15,212,725	28
						29
						30
06-24-2008	01-15-2038	06-24-2008	01-15-2038	110,000,000	6,473,500	31
						32
				4,929,035,579	253,679,997	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	4.35% Series, due 2042	250,000,000	2,559,708
3			207,500 D
4	4.35% Series, due 2042	250,000,000	2,559,709
5			-21,570,000 P
6			
7	6.50% Series, due 2018	300,000,000	2,214,194
8			861,000 D
9			
10	6.05% Series, due 2038	175,000,000	1,916,924
11			728,000 D
12			
13	5.50% Series, due 2039	150,000,000	1,517,157
14			1,179,000 D
15			
16	3.22% Series, due 2021	30,000,000	329,625
17			
18	5.45% Series, due 2041	250,000,000	2,187,500
19			917,500 D
20			
21	5.45% Series, due 2041	100,000,000	1,361,577
22			-2,799,000 P
23			
24	4.60% Series, due 2043	400,000,000	4,234,911
25			2,000,000 D
26			
27	5.10% Series, due 2065	500,000,000	5,325,812
28			4,035,000 D
29			
30	4.10% Series, due 2046 (State Commission Order No. 2013-277 Issued on 05-09-2013)	425,000,000	3,718,750
31			875,500 D
32			
33	TOTAL	5,029,541,381	52,302,580

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
01-30-2012	02-01-2042	01-30-2012	02-01-2042	250,000,000	10,875,000	2
						3
07-13-2012	02-01-2042	07-13-2012	02-01-2042	250,000,000	10,875,000	4
						5
						6
10-02-2008	11-01-2018	10-02-2008	11-01-2018	300,000,000	19,500,000	7
						8
						9
03-17-2009	01-15-2038	03-17-2009	01-15-2038	175,000,000	10,681,275	10
						11
						12
12-09-2009	12-15-2039	12-09-2009	12-15-2039	150,000,000	8,250,000	13
						14
						15
10-18-2011	10-18-2021	10-18-2011	10-18-2021	30,000,000	966,000	16
						17
01-27-2011	02-01-2041	01-27-2011	02-01-2041	250,000,000	13,625,000	18
						19
						20
05-24-2011	02-01-2041	05-24-2011	02-01-2041	100,000,000	5,450,000	21
						22
						23
06-14-2013	06-15-2043	06-14-2013	06-15-2043	400,000,000	18,400,000	24
						25
						26
06-01-2015	06-01-2065	06-01-2015	06-01-2065	500,000,000	25,500,000	27
						28
						29
06-13-2016	06-15-2046	06-13-2016	06-15-2046	425,000,000	9,535,347	30
						31
						32
				4,929,035,579	253,679,997	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Pollution Control Facilities Revenue Bonds:		
3	4% Industrial Revenue, due 2028	39,480,000	426,014
4			-2,694,115 P
5			
6	3.625% Industrial Revenue, due 2033	14,735,000	158,164
7			258,157 D
8			
9	Variable Industrial Revenue, due 2038	35,000,000	492,221
10			
11	Amortization of Interest Rate Derivative Contracts:		
12	6.625% $300 Million due 2/1/2032		
13	5.80% $200 Million due 1/15/2033		
14	6.25% $125 Million due 7/1/2036		
15	5.30% $300 Million due 5/21/2033		
16	5.25% $250 Million due 11/1/2018		
17	5.25% $100 Million due 3/1/2035		
18	6.05% $250 Million due 1/15/2038		
19	6.05% $110 Million due 1/15/2038		
20	6.05% $175 Million due 1/15/2038		
21	5.50% $150 Million due 12/15/2039		
22	5.45% $250 Million due 2/1/2041		
23	5.45% $100 Million due 2/1/2041		
24	4.35% $250 Million due 2/01/2042		
25	4.35% $250 Million due 2/01/2042		
26	4.60% $75 Million due 6/14/2043		
27	4.60% $75 Million due 6/14/2043		
28	4.60% $90 Million due 6/14/2043		
29	4.60% $80 Million due 6/14/2043		
30	4.60% $80 Million due 6/14/2043		
31	$35 Million SIFMA due 11/30/2038		
32	4.50% $300 Million due 06/01/2064		
33	TOTAL	5,029,541,381	52,302,580

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
01-15-2013	02-01-2028	01-15-2013	02-01-2028	39,480,000	1,579,200	3
						4
						5
01-15-2013	02-01-2033	01-15-2013	02-01-2033	14,735,000	534,144	6
						7
						8
12-01-2008	12-01-2038	12-01-2008	12-01-2038	34,555,000	1,015,902	9
						10
						11
		01-31-2002	02-01-2032		-32,251	12
		01-23-2003	01-15-2033		-5,185	13
		06-27-2006	07-01-2036		-194,951	14
		05-21-2003	05-15-2033		321,412	15
		11-06-2003	11-01-2018		302,671	16
		03-08-2005	03-01-2035		46,107	17
		01-14-2008	01-15-2038		263,307	18
		06-24-2008	01-15-2038		-10,073	19
		03-17-2009	01-15-2038		363,375	20
		12-09-2009	12-15-2039		-423,481	21
		01-27-2011	02-01-2041		289,740	22
		05-24-2011	02-01-2041		207,282	23
		01-30-2012	02-01-2042		-256,278	24
		07-13-2012	02-01-2042		-25,471	25
		06-14-2013	06-15-2043		282,178	26
		06-14-2013	06-15-2043		283,034	27
		06-14-2013	06-15-2043		-324,505	28
		06-14-2013	06-15-2043		-290,385	29
		06-14-2013	06-15-2043		-282,868	30
		12-01-2013	11-30-2038		-132,248	31
		06-01-2014	06-01-2064		163,206	32
				4,929,035,579	253,679,997	33

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.50% $75 Million due 06/01/2064		
2	5.10% $500 Million due 06/01/2065		
3	4.10% $425 Million due 06/15/2046		
4	SUBTOTAL - Account 221	4,929,215,000	49,476,097
5			
6	Account 224 - Other Long Term Debt:		
7	Variable Rate Lines of Credit		
8	Contract on Natural Gas Distribution system		
9	Acquired from Charleston AFB	424,844	
10	Commitment Fees		
11	Nuclear Fuel Contract	99,901,537	2,826,483 D
12	SUBTOTAL - Account 224	100,326,381	2,826,483
13			
14			
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27			
28			
29			
30			
31			
32			
33	TOTAL	5,029,541,381	52,302,580

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		06-13-2016	06-01-2064		36,717	1
		06-01-2015	06-01-2065		311,720	2
		06-13-2016	06-15-2046		765,827	3
				4,928,770,000	249,050,723	4
						5
						6
						7
						8
				265,579	12,690	9
					3,176,424	10
03-01-2013	11-01-2016	03-01-2013	11-01-2016		1,440,160	11
				265,579	4,629,274	12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				4,929,035,579	253,679,997	33

Schedule Page: 256 Line No.: 1 Column: c

With respect to unamortized amounts (premium, discount or expense) of debt redeemed, the Company follows the provisions set forth in General Instruction No. 17 of the Uniform System of Accounts. The Company records any unamortized amounts related to the redeemed debt to account 189 "Unamortized Loss on Reacquired Debt" or account 257 "Unamortized Gain on Reacquired Debt" as appropriate and amortizes this amount over the life of the new issue if refunded or over the remaining life of the original debt if not refunded.

Schedule Page: 256.3 Line No.: 7 Column: a

The Company had no long-term borrowings against its revolving credit agreements. These agreements expire in December 2018 and December 2020.

Schedule Page: 256.3 Line No.: 9 Column: a

In 2007, the Company was awarded the contract for the privatization of the natural gas distribution system at the Charleston Air Force Base. On September 1, 2007, ownership of the system transferred to the Company and the Company recorded assets totaling $424,844 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off this long-term debt through applied billing credits over a period of 20 years. As of 12/31/2016, the outstanding amount related to this obligation was $265,579.

Schedule Page: 256.3 Line No.: 10 Column: i

SCANA Holding Company (parent of SCE&G) allocates interest expense on commitment fees to its operating subsidiaries. During 2016, the portion allocated to SCE&G was $289,738.

Schedule Page: 256.3 Line No.: 11 Column: a

In February 2013, SCE&G entered into a contract to acquire Enriched Uranium Product (EUP) for the initial core load of the V.C. Summer Nuclear Station Unit No. 3 currently under construction. Under the provisions of the contract, SCE&G recorded $99.9 million within Account 224 - Other Long-Term Debt and $2.8 million within Account 226 - Unamortized Discount on Long-Term Debt. Payment to satisfy the obligation was made in November 2016.

Schedule Page: 256.3 Line No.: 13 Column: i

The interest expense of $6,296,983 included in account 430 "Interest on Debt to Associated Companies" is related to short-term debt and therefore is not included in this schedule.

Schedule Page: 256.3 Line No.: 15 Column: a

The Company has authorization from the South Carolina Public Service Commission to issue up to $3.5 billion of First Mortgage Bonds(State Commission Order Nos. 2013-277 and 2016-564). As of 12/31/2016, the Company had issued $1.24 billion under such authorization.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	512,691,483
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized	214,487,780
6	Pension Plan	1,380,543
7	Recovery of Deferred Capacity	296,000
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Total Net Book Income Tax (Including Investment Tax Credit)	240,215,857
11	Book Depreciation and Amortization	269,797,518
12	Book Expense - Nuclear Fuel	56,467,219
13	Other (see detail)	71,930,913
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	44,134,820
16	Regulatory Asset - Carrying Costs	13,970,852
17	Regulatory Asset Deferred Capacity	6,238,082
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	1,224,241,496
21	Repair Allowance Deduction	46,745,212
22	Domestic Production Activities Deduction	44,793,992
23	Contributions in Aid of Construction	17,563,142
24	Storm Damage Costs	23,607,306
25	Cybersecurity	7,317,071
26	Other (see detail)	15,481,010
27	Federal Tax Net Income	-76,825,670
28	Show Computation of Tax:	
29	Tax @ 35%	-26,888,985
30		
31	Adjustments for Prior Years	-117,517,970
32	Other (see detail)	-11,235,480
33	Current Federal Income Tax Expense Recorded	-155,642,435
34		
35		
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43		
44		

Schedule Page: 261 Line No.: 13 Column: b

Deferred Fuel Costs	$24,322,080
Deferred Nuclear Fuel Expenses	15,580,797
Regulatory Asset - Unrecovered Plant	9,135,210
Other Post Retirement Benefits	3,620,647
Nuclear Decommissioning Expense Accrual	3,210,606
Injuries and Damages	2,504,442
Book Vehicle Depreciation Charged to Operations	2,503,377
Section 162m limitation	2,501,376
Net Metering	1,757,750
Pollution Control	1,344,598
Coal Supply Contract Termination	1,200,000
Amortization of Losses on Reacquired Debt	1,142,386
Environmental Remediation Costs	798,991
Meals and Lobbying	710,000
Demand Side Management	519,610
Regulatory Asset - Customer Programs	335,103
Uncollectible Accounts	275,701
VCS Costs	183,816
Directors' Endowment	157,028
All Other	127,395
Total	$71,930,913

Schedule Page: 261 Line No.: 26 Column: b

Major Maintenance Programs	$ 5,521,170
State Income Tax Deduction	(2,398,715)
Gas Pipeline Integrity	2,233,149
Early Retirement Programs	1,834,068
Gas WNA Cap	1,811,353
Regulatory Asset - Interest/Professional Fees	1,682,475
Prepayment Acceleration	1,217,757
Regulatory Asset - McMeekin	1,005,199
Long Term Disability	797,117
Accrued Vacation	592,163
Fukushima Compliance	427,884
All Other	757,390
Total	$15,481,010

Schedule Page: 261 Line No.: 32 Column: b

Partnership Credits	($ 8,252,167)
Regulatory Asset - Sec 41/Sec 199	(2,983,313)
Total	($11,235,480)

Schedule Page: 261 Line No.: 33 Column: b

South Carolina Electric & Gas Company is a wholly owned subsidiary of SCANA Corporation and is included in the consolidated federal income tax return of SCANA Corporation. Taxes are allocated to members based on their contributions to the consolidated total. Current federal income taxes recorded in 2016 by each member of the consolidated group were as follows:

SCANA Corporation	($ 21,613,000)
SCANA Communications Holding, Inc.	410,284
SCANA Services	5,064,100
South Carolina Electric & Gas Company	(158,874,935)*
South Carolina Fuel Company	3,232,500 *
South Carolina Generating Company	1,526,840
Public Service of North Carolina	(15,947,900)
PSNC Blue Ridge Corporation	507,200
PSNC Clean Energy Enterprises, Inc.	(400)
PSNC Cardinal Pipeline Corporation	1,156,100
SCANA Energy Marketing, Inc.	15,814,300
Servicecare, Inc.	(401,900)
Total	($169,126,811)

* ($155,642,435)

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	133,512,837		-155,642,435	70,530,962	92,660,560
3	FUTA	4,421		240,882	236,836	-3,222
4	FICA	755,937		32,954,030	32,419,211	-456,945
5	Other Miscellaneous		18,975	36,300	36,318	
6	SUBTOTAL	134,273,195	18,975	-122,411,223	103,223,327	92,200,393
7						
8	State:					
9	Income	30,260,353		-18,521,476	28,580,507	16,841,630
10	License			15,558,278	15,558,278	
11	Vehicle License			195,754	195,754	
12	Electric Generation	446,156		7,318,334	7,294,250	
13	SUTA	7,217		528,686	519,719	-6,676
14	Other Miscellaneous					
15	SUBTOTAL	30,713,726		5,079,576	52,148,508	16,834,954
16						
17	Local:					
18	County Property	163,330,465	608,528	180,188,699	164,695,505	
19	Municipal Property	9,051,422		9,412,475	8,588,175	
20	SUBTOTAL	172,381,887	608,528	189,601,174	173,283,680	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
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39						
40						
41	TOTAL	337,368,808	627,503	72,269,527	328,655,515	109,035,347

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		-144,978,100			-10,664,335	2
5,245		90,848			150,034	3
833,811		12,887,390			20,066,640	4
	18,993				36,300	5
839,056	18,993	-131,999,862			9,588,639	6
						7
						8
		-18,767,040			245,564	9
		13,743,589			1,814,689	10
					195,754	11
470,240		7,318,334				12
9,508		188,281			340,405	13
						14
479,748		2,483,164			2,596,412	15
						16
						17
178,828,708	613,577	158,134,174			22,054,525	18
9,875,722		8,274,507			1,137,968	19
188,704,430	613,577	166,408,681			23,192,493	20
						21
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190,023,234	632,570	36,891,983			35,377,544	41

Schedule Page: 262 Line No.: 2 Column: f

Reclassified amount to account 186 - Misc Deferred Debits	$70,282,000
Reclassified amount to account 282 - Accumulated Deferred Income Taxes	(25,859,800)
Overpayment of taxes reclassified to account 143 - Other Accounts Receivable	40,728,060
Reclassified amount to account 182 - Regulatory Asset	7,510,300
Total	$92,660,560

Schedule Page: 262 Line No.: 3 Column: f

Estimated payroll taxes in the amount of ($3,131,055) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2016. Those adjustments are combined with a total of $2,664,212 of payroll taxes related to at-risk incentive compensation actually paid in 2016 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($466,843).

Schedule Page: 262 Line No.: 4 Column: f

Estimated payroll taxes in the amount of ($3,131,055) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2016. Those adjustments are combined with a total of $2,664,212 of payroll taxes related to at-risk incentive compensation actually paid in 2016 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($466,843).

Schedule Page: 262 Line No.: 9 Column: f

Overpayment of taxes reclassified to account 143 - Other Accounts Receivable	$20,843,530
Reclassified amount to account 282 - Accumulated Deferred Income Taxes	(4,001,900)
Total	$16,841,630

Schedule Page: 262 Line No.: 13 Column: f

Estimated payroll taxes in the amount of ($3,131,055) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2016. Those adjustments are combined with a total of $2,664,212 of payroll taxes related to at-risk incentive compensation actually paid in 2016 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($466,843).

Schedule Page: 262 Line No.: 22 Column: a

Taxes related to the Company's common utility operations are apportioned to electric and gas operations based on functional usage of common property, revenue or payroll as applicable.

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	232,112			411.4	40,500	
4	7%						
5	10%	16,354,646			411.4	910,800	
6	8%	5,374,268			411.4	324,100	
7	20%	48,674			411.4	4,200	
8	TOTAL	22,009,700				1,279,600	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	25,534			411.4	5,100	
13	10%	644,815			411.4	52,400	
14	20%	13,292			411.4	900	
15	8%	887,159			411.4	54,200	
16	Total Gas	1,570,800				112,600	
17							
18							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
191,612	58.4 Years		3
			4
15,443,846	58.4 Years		5
5,050,168	58.4 Years		6
44,474	58.4 Years		7
20,730,100			8
			9
			10
			11
20,434	47.5 Years		12
592,415	47.5 Years		13
12,392	47.5 Years		14
832,959	47.5 Years		15
1,458,200			16
			17
			18
			19
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			48

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accrued Pension Liability - Early					
2	Retirement Incentive Programs &					
3	Other	10,706,259	Various	2,966,654	1,132,586	8,872,191
4	Accrued Liability - Incentive Plan	4,466,531	Various	38,852,042	39,018,888	4,633,377
5	Gas Environmental Remediation	18,544,499	182.3	101,694,928	93,373,262	10,222,833
6	Other Environmental Remediation	609,200	Various	23,063,400	23,065,776	611,576
7	Long-Term Disability	1,728,353	131	2,111,652	1,314,535	931,236
8	Accrued Liability - Director's					
9	Endowment Program	3,126,294	131	78,374	206,858	3,254,778
10	Life Insurance Premium Obligation	5,996	926	6,057	3,118	3,057
11	Santee River Basin Accord	1,145,905	131	135,308	35,528	1,046,125
12	Municipal Nonstandard Service Fund					
13	Matching Obligation	5,007,710	186	18,910,124	19,647,565	5,745,151
14	SRS Substation	1,901,603	456	96,283		1,805,320
15	Interconnection Study Deposits	535,451	234/456	1,489,471	1,271,864	317,844
16	New Nuclear Transmission Lines	90,000	131	90,000		
17	CIAC Obligations	17,914,870	107/118	3,876,283	3,197,321	17,235,908
18	Noncontrolling Interest - SCFC	2,696,226				2,696,226
19	FIN 48 Interest		431	411,700	2,770,500	2,358,800
20	Other	776,926	Various	2,831,803	3,005,634	950,757
21						
22						
23						
24						
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44						
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46						
47	TOTAL	69,255,823		196,614,079	188,043,435	60,685,179

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	12,361,300		322,000
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	12,361,300		322,000
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	12,361,300		322,000
18	Classification of TOTAL			
19	Federal Income Tax	10,745,400		279,900
20	State Income Tax	1,615,900		42,100
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						12,039,300	4
							5
							6
							7
						12,039,300	8
							9
							10
							11
							12
							13
							14
							15
							16
						12,039,300	17
							18
						10,465,500	19
						1,573,800	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,370,839,208	578,229,200	174,717,185
3	Gas	153,285,200	18,954,100	3,097,200
4	Other - Non Operating	8,810,700		
5	TOTAL (Enter Total of lines 2 thru 4)	1,532,935,108	597,183,300	177,814,385
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,532,935,108	597,183,300	177,814,385
10	Classification of TOTAL			
11	Federal Income Tax	1,364,350,091	526,334,600	156,919,200
12	State Income Tax	168,585,017	70,848,700	20,895,185
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
		182.3	2,397,593	182.3/236.0	54,520,900	1,826,474,530	2
		182.3	681,800	182.3	1,279,200	169,739,500	3
3,700	1,360,900					7,453,500	4
3,700	1,360,900		3,079,393		55,800,100	2,003,667,530	5
							6
							7
							8
3,700	1,360,900		3,079,393		55,800,100	2,003,667,530	9
							10
3,000	1,183,600		2,707,951		48,520,600	1,778,397,540	11
700	177,300		371,442		7,279,500	225,269,990	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Asset - ARO	115,255,100	7,730,900	316,000
4	Employee Benefit Plan Costs	73,025,300	11,023,400	3,082,400
5	Unrecovered Plant Canadys	49,246,400		4,669,600
6	Prepayments	24,830,600	953,300	
7	Demand Side Management Costs	22,951,600	383,400	526,300
8	All Other	-9,574,800	27,861,800	39,053,900
9	TOTAL Electric (Total of lines 3 thru 8)	275,734,200	47,952,800	47,648,200
10	Gas			
11	Employee Benefit Plan Costs	11,320,400	668,300	480,500
12	Regulatory Asset - ARO	6,466,500	430,500	
13	Deferred Fuel Costs	2,684,900	8,450,700	5,684,200
14	Prepayments	4,135,600		485,900
15	Gas Pipeline Integrity	1,424,300	854,300	
16	All Other	-317,900	1,701,400	621,100
17	TOTAL Gas (Total of lines 11 thru 16)	25,713,800	12,105,200	7,271,700
18	Non Operating	63,769,800		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	365,217,800	60,058,000	54,919,900
20	Classification of TOTAL			
21	Federal Income Tax	317,476,600	52,207,300	47,764,800
22	State Income Tax	47,741,200	7,850,700	7,155,100
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						122,670,000	3
						80,966,300	4
						44,576,800	5
						25,783,900	6
						22,808,700	7
				182.3	4,653,500	-16,113,400	8
					4,653,500	280,692,300	9
							10
						11,508,200	11
						6,897,000	12
						5,451,400	13
						3,649,700	14
						2,278,600	15
						762,400	16
						30,547,300	17
5,633,100	6,482,300			219	80,400	63,001,000	18
5,633,100	6,482,300				4,733,900	374,240,600	19
							20
4,896,700	5,634,500				4,115,100	325,296,400	21
736,400	847,800				618,800	48,944,200	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Deferred Fuel Costs	($10,139,300)	$15,862,200	$27,930,700		($22,207,800)
Pension Plan	(14,705,600)	3,001,000	8,515,800		(20,220,400)
Regulatory Asset- Deferred Capacity	4,145,300	2,386,100	-		6,531,400
Reacquired Debt	5,532,400	97,600	436,900		5,193,100
FAS109 - Sec 174	-	-	-	$4,653,500	4,653,500
Cyber Security	-	4,084,600	-		4,084,600
VCS Costs	1,864,300	-	70,300		1,794,000
Fukushima Compliance	1,412,400	163,700	10,300		1,565,800
Grants	841,500	153,000	-		994,500
Regulatory Asset- Professional Fees	-	643,700	-		643,700
Recovery of Deferred Capacity	514,200	-	116,700		397,500
All Other	960,000	1,469,900	1,973,200		456,700
Total	($ 9,574,800)	$27,861,800	$39,053,900	$4,653,500	($16,113,400)

Schedule Page: 276 Line No.: 16 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Balance at End of Year
Gas WNA Cap		$ 1,149,800		$ 1,149,800
Pension Plan	($1,207,100)	551,600	$ 402,400	(1,057,900)
Reacquired Debt	676,500	-	87,600	588,900
Regulatory Asset- Customer Programs	212,700	-	131,100	81,600
Total	($ 317,900)	$ 1,701,400	$ 621,100	$ 762,400

Schedule Page: 276 Line No.: 18 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.2	Amt. Credited Acct.411.2	Adjust.	Balance at End of Year
Pension Plan	$50,297,100	$ -	$ 46,300	$ 80,400	$50,331,200
Regulatory Asset- Carrying Costs	6,974,000	5,343,900	200		12,317,700
FIN48 Interest	423,000	281,700	332,900		371,800
Partnership Credits	6,075,700	7,500	6,102,900		(19,700)
Total	$63,769,800	$ 5,633,100	$ 6,482,300	$ 80,400	$63,001,000

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Accumulated Deferred Income Tax Credits	14,606,600	190	862,300		13,744,300
2	Storm Damage Reserve	3,900,815	571/593	3,900,815		
3	Nuclear Refueling Accrual		524/528	11,405,361	23,082,433	11,677,072
4	NOX Emission Allowance Proceeds	153,865	447	153,295	463	1,033
5	Interest Rate Derivatives (3/2009-6/2043)	96,111,382	176/427/421	16,609,739	71,128,530	150,630,173
6	Demand Side Management Carrying Costs	5,952,053	182.3	1,781,297	562,055	4,732,811
7	SO2 Emission Allowance Proceeds	871			86	957
8	Wholesale Fuel Overcollection	1,077,834	447	859,879	1,649,389	1,867,344
9	Amt. Overcollected - Elec Fuel Adjustment Clause	25,431,776	449/173	151,121,526	181,882,008	56,192,258
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41	TOTAL	147,235,196		186,694,212	278,304,964	238,845,948

Schedule Page: 278   Line No.: 2   Column: a

SCPSC Docket No. 95-1000-E
SCPSC Docket No. 2007-335-E
SCPSC Docket No. 2008-416-E
SCPSC Docket No. 2009-489-E
SCPSC Docket NO. 2012-218-E

Schedule Page: 278   Line No.: 3   Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 278   Line No.: 5   Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

Schedule Page: 278   Line No.: 6   Column: a

SCPSC Docket No. 2013-50-E
SCPSC Docket No. 2013-208-E
SCPSC Docket No. 2014-44-E
SCPSC Docket No. 2015-45-E
SCPSC Docket No. 2016-40-E

Schedule Page: 278   Line No.: 9   Column: a

SCPSC Docket No. 2016-2-E

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,184,394,884	1,144,628,202
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	850,736,352	829,184,845
5	Large (or Ind.) (See Instr. 4)	433,854,479	427,958,743
6	(444) Public Street and Highway Lighting	14,775,119	14,364,720
7	(445) Other Sales to Public Authorities	47,755,097	47,280,395
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,531,515,931	2,463,416,905
11	(447) Sales for Resale	45,568,557	49,093,118
12	TOTAL Sales of Electricity	2,577,084,488	2,512,510,023
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,577,084,488	2,512,510,023
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,778,151	7,199,589
17	(451) Miscellaneous Service Revenues	4,156,675	3,698,815
18	(453) Sales of Water and Water Power	385,910	431,911
19	(454) Rent from Electric Property	19,530,616	20,040,653
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	3,598,591	5,165,454
22	(456.1) Revenues from Transmission of Electricity of Others	7,839,445	8,058,377
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	42,289,388	44,594,799
27	TOTAL Electric Operating Revenues	2,619,373,876	2,557,104,822

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
8,139,813	7,977,834	605,717	596,686	2
				3
7,518,727	7,398,918	94,375	93,178	4
6,264,991	6,201,242	783	757	5
74,895	73,740	1,025	1,022	6
525,787	520,849	3,125	3,191	7
				8
				9
22,524,213	22,172,583	705,025	694,834	10
946,981	942,262	4	4	11
23,471,194	23,114,845	705,029	694,838	12
				13
23,471,194	23,114,845	705,029	694,838	14

Line 12, column (b) includes $ 91,773,090 of unbilled revenues.

Line 12, column (d) includes 721,010 MWH relating to unbilled revenues

Name of Respondent South Carolina Electric & Gas Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2016/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 5 Column: d

Includes 3,332 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 5 Column: e

Includes 3,267 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 10 Column: b

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($10,769,575)
Commercial	(10,195,741)
Industrial	(8,965,839)
Street Lighting	(108,360)
Other Public Authorities	(720,965)
	($30,760,480)

Includes Unmetered Sales Revenue as follows:

Residential	$18,994,642
Commercial/Industrial	29,322,905
Street Lighting	13,766,984
Other Public Authorities	137,414
	$62,221,945

Schedule Page: 300 Line No.: 10 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($31,953,022)
Commercial	(30,007,949)
Industrial	(25,682,833)
Street Lighting	(309,214)
Other Public Authorities	(2,133,595)
	($90,086,613)

Includes Unmetered Sales Revenue as follows:

Residential	$19,257,846
Commercial/Industrial	29,633,344
Street Lighting	13,520,908
Other Public Authorities	145,036
	$62,557,134

Schedule Page: 300 Line No.: 10 Column: d

Includes Unmetered MWH Sales as follows:

Residential	81,266
Commercial/Industrial	149,291
Street Lighting	67,525
Other Public Authorities	988
	299,070

Schedule Page: 300 Line No.: 10 Column: e

Includes Unmetered MWH Sales as follows:

Residential	80,027
Commercial/Industrial	148,709
Street Lighting	66,053
Other Public Authorities	1,038
	295,827

Schedule Page: 300 Line No.: 10 Column: f

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	210,488
Commercial/Industrial	24,928
Street Lighting	1,075
Other Public Authorities	59
	236,550

Schedule Page: 300 Line No.: 10 Column: g

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	209,733
Commercial/Industrial	24,858
Street Lighting	972
Other Public Authorities	59
	235,622

Schedule Page: 300 Line No.: 17 Column: b

Includes $1,457,749 of reconnect and lighting disconnect charges.

Includes $2,445,935 of transmission maintenance fee revenue.

Includes $538,840 of returned check fees.

Account balance also includes debit activity of ($439,186) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 17 Column: c

Includes $1,317,527 of reconnect and lighting disconnect charges.

Includes $2,254,755 of transmission maintenance fee revenue.

Includes $450,753 of returned check fees.

Account balance also includes debit activity of ($487,963) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 21 Column: b

Includes $1,998,242 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $415,235 of Telecommunication Tower Rent Revenue.

Includes $343,345 of Ground and Telecommunication Rack lease Revenue.

Includes $434,741 of Timber Sales Revenue.

Schedule Page: 300 Line No.: 21 Column: c

Includes $4,362,458 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $401,419 of rental income.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales by Rate					
2	1	332,590	46,266,484	21,316	15,603	0.1391
3	2	24,059	4,359,475	15,241	1,579	0.1812
4	5	1,061	151,758	69	15,377	0.1430
5	6	477,597	66,529,604	31,243	15,287	0.1393
6	7	292	36,526	10	29,200	0.1251
7	8	7,209,348	1,046,196,194	536,356	13,441	0.1451
8	E1N	671	96,650	70	9,586	0.1440
9	E2N	4	1,090	5	800	0.2725
10	E5N	9	1,218	1	9,000	0.1353
11	E6N	789	115,554	98	8,051	0.1465
12	E8N	8,106	1,232,979	1,048	7,735	0.1521
13	M1N	339	47,138	20	16,950	0.1391
14	M2N	2	464	2	1,000	0.2320
15	M5N	4	627	1	4,000	0.1568
16	M6N	549	76,779	40	13,725	0.1399
17	M8N	2,635	382,949	197	13,376	0.1453
18	Special (A)	81,759	18,899,395	210,488	388	0.2312
19	Total Residential	8,139,814	1,184,394,884	816,205	9,973	0.1455
20						
21	Commerical & Industrial Sales					
22	by Rate					
23	3	16,681	1,935,394	349	47,797	0.1160
24	9	2,669,981	362,478,075	79,092	33,758	0.1358
25	10	4,802	914,501	2,216	2,167	0.1904
26	11	15,969	1,647,545	318	50,217	0.1032
27	12	164,992	18,860,172	3,697	44,629	0.1143
28	14	21,705	3,174,728	1,851	11,726	0.1463
29	16	44,966	5,944,826	2,836	15,855	0.1322
30	20	1,900,899	200,604,151	2,156	881,679	0.1055
31	21	365,407	35,342,078	548	666,801	0.0967
32	22	419,750	50,327,991	1,740	241,236	0.1199
33	23	4,107,370	306,714,995	122	33,666,967	0.0747
34	24	2,037,082	172,968,599	181	11,254,597	0.0849
35	27	926,085	60,414,812	10	92,608,500	0.0652
36	28	2,422	301,128	20	121,100	0.1243
37	60	934,875	34,337,599	3	311,625,000	0.0367
38	E9N	1,058	140,042	20	52,900	0.1324
39	Special (A)	149,675	28,484,195	24,390	6,137	0.1903
40	Total Commercial & Industrial	13,783,719	1,284,590,831	119,549	115,298	0.0932
41	TOTAL Billed	21,803,203	2,439,742,841	0	0	0.1119
42	Total Unbilled Rev.(See Instr. 6)	721,010	91,773,090	0	0	0.1273
43	TOTAL	22,524,213	2,531,515,931	0	0	0.1124

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Public Street & Highway					
2	Lighting Sales by Rate					
3	3	1,448	188,776	99	14,626	0.1304
4	9	2,361	451,418	545	4,332	0.1912
5	13	3,812	498,126	382	9,979	0.1307
6	Special (A)	67,272	13,636,799	1,059	63,524	0.2027
7	Total Public Street & Hwy Lights	74,893	14,775,119	2,085	35,920	0.1973
8						
9	Other Sales to Public Authorities					
10	by Rate					
11	3	145,519	16,830,073	2,917	49,887	0.1157
12	9	1,440	214,404	145	9,931	0.1489
13	20	12,600	1,187,557	7	1,800,000	0.0943
14	21	3,222	293,560	3	1,074,000	0.0911
15	65	70,801	5,432,159	21	3,371,476	0.0767
16	66	291,931	23,757,298	32	9,122,844	0.0814
17	Special (A)	274	40,046	10	27,400	0.1462
18	Total OPAs	525,787	47,755,097	3,135	167,715	0.0908
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41	TOTAL Billed	21,803,203	2,439,742,841	0	0	0.1119
42	Total Unbilled Rev.(See Instr. 6)	721,010	91,773,090	0	0	0.1273
43	TOTAL	22,524,213	2,531,515,931	0	0	0.1124

Schedule Page: 304 Line No.: 19 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($10,769,575)
Commercial	(10,195,741)
Industrial	(8,965,839)
Street Lighting	(108,360)
Other Public Authorities	(720,965)
	($30,760,480)

Schedule Page: 304 Line No.: 40 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($10,769,575)
Commercial	(10,195,741)
Industrial	(8,965,839)
Street Lighting	(108,360)
Other Public Authorities	(720,965)
	($30,760,480)

Schedule Page: 304.1 Line No.: 7 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($10,769,575)
Commercial	(10,195,741)
Industrial	(8,965,839)
Street Lighting	(108,360)
Other Public Authorities	(720,965)
	($30,760,480)

Schedule Page: 304.1 Line No.: 18 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($10,769,575)
Commercial	(10,195,741)
Industrial	(8,965,839)
Street Lighting	(108,360)
Other Public Authorities	(720,965)
	($30,760,480)

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Town of McCormick	RQ		3.5	3.7	3.7
2	City of Orangeburg	RQ		136.0	146.4	142.5
3	Town of Winnsboro	RQ		12.0	11.7	11.5
4	Cargill Power Markets, LLC	OS				
5	Duke Energy Carolinas, LLC	OS				
6	Morgan Stanley Capital Group, Inc.	OS				
7	The Energy Authority, Inc.	OS				
8	Emissions Allow Sales - Revenue Contra					
9	Wholesale Fuel Over/Under Collection					
10						
11						
12	Transmission Revenue included in					
13	Energy Charges Column (i).					
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
20,600	539,753	611,149		1,150,902	1
843,444	11,940,202	28,862,323		40,802,525	2
64,165	1,209,125	2,180,926	146,892	3,536,943	3
16,747		622,646		622,646	4
1,700		74,650		74,650	5
200		8,400		8,400	6
125		5,625		5,625	7
			-476	-476	8
			-632,658	-632,658	9
					10
					11
					12
					13
					14
928,209	13,689,080	31,654,398	146,892	45,490,370	
18,772	0	711,321	-633,134	78,187	
946,981	**13,689,080**	**32,365,719**	**-486,242**	**45,568,557**	

Schedule Page: 310 Line No.: 1 Column: c

FERC Electric Tariff, Fourth Revised Volume No. 1

Schedule Page: 310 Line No.: 2 Column: c

FERC Electric Rate Schedule No. 60

Schedule Page: 310 Line No.: 3 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2 for the time period 1/1/2016 through 5/31/2016. Winnsboro PSA for the time period 6/1/2016 - 12/31/2016.

Schedule Page: 310 Line No.: 3 Column: j

Network transmission and ancillary services charges for the Town of Winnsboro. The transmission reservation that was held by SCE&G Power Marketing as agent for the Town of Winnsboro terminated on 05/31/2016. Transmission base revenue totals $129,212 and ancillary services revenue totals $17,680 through 05/2016.

Schedule Page: 310 Line No.: 4 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 4 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 5 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 5 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 6 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c)

Schedule Page: 310 Line No.: 6 Column: c

FERC Electric tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 7 Column: b

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 7 Column: c

FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 8 Column: j

Transfer of gain/loss on sale of emission allowances to Account 254 - Other Regulatory Liabilities for purchasing future emission allowances.

Schedule Page: 310 Line No.: 9 Column: j

Over/under collection of fuel relating to sales to wholesale customers.

Schedule Page: 310 Line No.: 13 Column: i

Subtotal non-RQ of $711,321 includes transmission revenue for OS service of $123,003. Transmission base revenue totals $116,212 and ancillary services revenue totals $6,791.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,542,754	2,419,201
5	(501) Fuel	241,232,166	280,051,019
6	(502) Steam Expenses	16,631,366	13,218,658
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	6,020,395	5,537,786
10	(506) Miscellaneous Steam Power Expenses	5,762,431	6,232,820
11	(507) Rents	4,500	1,500
12	(509) Allowances	-137,732	19,389
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	272,055,880	307,480,373
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	91,613	85,716
16	(511) Maintenance of Structures	1,361,389	1,862,262
17	(512) Maintenance of Boiler Plant	12,333,379	12,896,627
18	(513) Maintenance of Electric Plant	11,543,547	12,615,664
19	(514) Maintenance of Miscellaneous Steam Plant	4,513,165	6,265,718
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	29,843,093	33,725,987
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	301,898,973	341,206,360
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	12,421,296	9,399,979
25	(518) Fuel	56,467,219	45,687,791
26	(519) Coolants and Water	2,876,256	3,149,217
27	(520) Steam Expenses	6,316,647	7,326,705
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	1,566,158	2,359,644
31	(524) Miscellaneous Nuclear Power Expenses	41,091,216	37,477,684
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	120,738,792	105,401,020
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	15,200,712	-3,055,152
36	(529) Maintenance of Structures	2,738,627	3,106,875
37	(530) Maintenance of Reactor Plant Equipment	3,069,010	14,474,420
38	(531) Maintenance of Electric Plant	2,500,132	3,416,419
39	(532) Maintenance of Miscellaneous Nuclear Plant	10,319,397	17,185,353
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	33,827,878	35,127,915
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	154,566,670	140,528,935
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	702,170	770,952
45	(536) Water for Power		
46	(537) Hydraulic Expenses	1,286,134	1,398,001
47	(538) Electric Expenses	181,718	162,263
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,089,500	726,151
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	3,259,522	3,057,367
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	152,188	145,819
54	(542) Maintenance of Structures	18,362	7,785
55	(543) Maintenance of Reservoirs, Dams, and Waterways	702,406	1,034,426
56	(544) Maintenance of Electric Plant	3,104,540	3,441,143
57	(545) Maintenance of Miscellaneous Hydraulic Plant	110,419	76,450
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,087,915	4,705,623
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	7,347,437	7,762,990

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,100,946	1,146,657
63	(547) Fuel	165,339,292	185,680,047
64	(548) Generation Expenses	5,023,761	4,757,331
65	(549) Miscellaneous Other Power Generation Expenses	1,554,627	1,617,315
66	(550) Rents	40,800	43,752
67	TOTAL Operation (Enter Total of lines 62 thru 66)	173,059,426	193,245,102
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	345,076	469,644
70	(552) Maintenance of Structures	553,263	584,816
71	(553) Maintenance of Generating and Electric Plant	13,764,550	11,824,623
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	663,459	654,807
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	15,326,348	13,533,890
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	188,385,774	206,778,992
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	254,194,400	282,221,548
77	(556) System Control and Load Dispatching	2,718,759	2,937,877
78	(557) Other Expenses	263,750	267,004
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	257,176,909	285,426,429
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	909,375,763	981,703,706
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	792,884	851,568
84			
85	(561.1) Load Dispatch-Reliability	1,076,009	1,038,723
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	773,525	599,016
87	(561.3) Load Dispatch-Transmission Service and Scheduling	169,113	186,478
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	45,352	48,676
90	(561.6) Transmission Service Studies	3,905	8,136
91	(561.7) Generation Interconnection Studies	-196,944	-191,571
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	437,299	452,676
94	(563) Overhead Lines Expenses	51,577	365,391
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	2,535,425	2,700,581
97	(566) Miscellaneous Transmission Expenses	3,600,428	3,137,388
98	(567) Rents	340,147	329,966
99	TOTAL Operation (Enter Total of lines 83 thru 98)	9,628,720	9,527,028
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	24,142	23,243
102	(569) Maintenance of Structures	27,498	15,526
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	4,839	7,755
105	(569.3) Maintenance of Communication Equipment	31,563	34,319
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,860,584	2,807,075
108	(571) Maintenance of Overhead Lines	5,133,521	5,213,367
109	(572) Maintenance of Underground Lines	15,803	99,900
110	(573) Maintenance of Miscellaneous Transmission Plant	245,447	255,156
111	TOTAL Maintenance (Total of lines 101 thru 110)	8,343,397	8,456,341
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	17,972,117	17,983,369

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	846,719	866,816
135	(581) Load Dispatching	973,693	967,713
136	(582) Station Expenses	574,535	605,692
137	(583) Overhead Line Expenses	1,464,753	1,392,041
138	(584) Underground Line Expenses	241,818	236,491
139	(585) Street Lighting and Signal System Expenses	416,277	337,282
140	(586) Meter Expenses	1,075,373	1,512,216
141	(587) Customer Installations Expenses	24,362	15,547
142	(588) Miscellaneous Expenses	7,483,654	7,452,109
143	(589) Rents	2,169,852	2,305,730
144	TOTAL Operation (Enter Total of lines 134 thru 143)	15,271,036	15,691,637
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	247,985	301,837
147	(591) Maintenance of Structures	6,720	10,205
148	(592) Maintenance of Station Equipment	3,516,089	3,663,286
149	(593) Maintenance of Overhead Lines	26,028,775	27,623,945
150	(594) Maintenance of Underground Lines	3,121,335	2,774,804
151	(595) Maintenance of Line Transformers	134,260	167,226
152	(596) Maintenance of Street Lighting and Signal Systems	3,634,155	2,715,852
153	(597) Maintenance of Meters	311,848	302,672
154	(598) Maintenance of Miscellaneous Distribution Plant	2,975,746	2,886,479
155	TOTAL Maintenance (Total of lines 146 thru 154)	39,976,913	40,446,306
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	55,247,949	56,137,943
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,558,673	1,699,047
160	(902) Meter Reading Expenses	1,895,936	1,772,854
161	(903) Customer Records and Collection Expenses	35,636,476	36,529,324
162	(904) Uncollectible Accounts	5,927,251	5,697,561
163	(905) Miscellaneous Customer Accounts Expenses	2,812,218	2,295,274
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	47,830,554	47,994,060

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	278,681	319,698
168	(908) Customer Assistance Expenses	14,392,900	12,828,632
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	98,018	281,313
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	14,769,599	13,429,643
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,195,106	1,504,308
176	(913) Advertising Expenses	1,872	-3,158
177	(916) Miscellaneous Sales Expenses	227,932	253,830
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,424,910	1,754,980
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	63,602,777	56,641,077
182	(921) Office Supplies and Expenses	18,141,449	17,782,876
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	13,514,667	15,282,833
185	(924) Property Insurance	7,022,817	6,719,399
186	(925) Injuries and Damages	6,898,273	6,982,006
187	(926) Employee Pensions and Benefits	55,383,403	39,648,705
188	(927) Franchise Requirements	6,077	8,569
189	(928) Regulatory Commission Expenses	5,244,577	5,324,591
190	(929) (Less) Duplicate Charges-Cr.	8,142,846	8,786,659
191	(930.1) General Advertising Expenses	20,700	157
192	(930.2) Miscellaneous General Expenses	18,051,631	16,226,454
193	(931) Rents	5,078,266	4,779,376
194	TOTAL Operation (Enter Total of lines 181 thru 193)	184,821,791	160,609,384
195	Maintenance		
196	(935) Maintenance of General Plant	6,905,304	6,334,105
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	191,727,095	166,943,489
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,238,347,987	1,285,947,190

Schedule Page: 320 Line No.: 12 Column: b

Credit due to the recognition, upon termination of the CAIR program, of previously realized gains from the sale of NOX emission allowances previously deferred in Account 254 - Other Regulatory Liabilities.

Schedule Page: 320 Line No.: 35 Column: c

In SCPSC Docket No. 2012-218-E, the SCPSC authorized the Company to establish a 5-cycle or 90 month recovery of nuclear outage costs for V.C. Summer Nuclear Station Unit 1. Accordingly, the Company is accruing $17.2 million annually with $13.9 million and $3.3 million being accrued to account 528 and 524, respectively. Differences between actual outage costs incurred and the accrued amounts are recognized as regulatory assets or liabilities as appropriate. During 2015, the Company reversed actual outage costs of $20.6 million from account 528 and applied such costs against the established regulatory liability. As a result, the Company has reported net credit activity for the year in account 528.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Georgia Power (Calhoun Falls)	OS	Schedule #793			
2	Newberry Electric Cooperative	RQ				
3	Santee Cooper	RQ				
4	Santee Cooper	RQ				
5	Columbia Energy, LLC	OS	Tariff #1			
6	International Paper	OS				
7	Misc. Territorial Customers	OS	Rate - PR1			
8	Southeastern Power Administration	RQ	1/2001, 12/2002			
9	South Carolina Generating Company, Inc	RQ	Schedule #1		543	464
10	Cargill Power Markets, LLC	OS	Schedule #1			
11	Duke Energy Carolinas, LLC	OS	Tariff #5			
12	Exelon Generation Company, LLC	OS	Tariff #3			
13	Morgan Stanley Capital Group, Inc	OS	Tariff #2			
14	Rainbow Energy Marketing Corporation	OS	Tariff #1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,550				76,014		76,014	1
802				137,637		137,637	2
26,539				991,033		991,033	3
490				95,032		95,032	4
12,270				365,082		365,082	5
4,007				147,035		147,035	6
692				32,976		32,976	7
49					68,332	68,332	8
2,991,906				193,888,768		193,888,768	9
111,044				3,187,190		3,187,190	10
5,000				221,100		221,100	11
82,837				2,109,123		2,109,123	12
40,254				1,012,427		1,012,427	13
101,105				3,609,960		3,609,960	14
4,978,837	473	1,361	17,495,704	244,322,340	-7,623,644	254,194,400	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	North Carolina Municipal Power					
2	Agency No. 1	OS				
3	Southern Company Services, Inc	OS	Tariff #4			
4	The Energy Authority, Inc	OS				
5	Duke Energy Carolinas, LLC	OS				
6	Duke Energy Progress, LLC	OS				
7	Saluda Solar I, LLC	OS				
8	TIG Sun Energy III, LLC	OS				
9	Billing Credit Agreement (BCA) DER					
10	Solar Power Purchases	OS				
11	Columbia Energy, LLC	IU	Tariff #1			
12	Southern Company Services, Inc	IF	Tariff #4			
13	Santee Cooper	LF		25		
14	Columbia Energy, LLC	EX	Tariff #5			
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
42,464				1,127,540		1,127,540	2
9,987				353,758		353,758	3
51,360			37,200	1,977,256		2,014,456	4
1,940				97,572		97,572	5
741				43,615		43,615	6
261				11,746		11,746	7
1,005				90,842		90,842	8
							9
271				103,632		103,632	10
1,177,818			9,890,800	26,198,598	188,370	36,277,768	11
307,334			3,539,904	8,287,700		11,827,604	12
5,111			4,027,800	194,833		4,222,633	13
	473	1,361		-38,129		-38,129	14
4,978,837	473	1,361	17,495,704	244,322,340	-7,623,644	254,194,400	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Adjustments					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-7,880,346	-7,880,346	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,978,837	473	1,361	17,495,704	244,322,340	-7,623,644	254,194,400	

Schedule Page: 326 Line No.: 1 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 1 Column: c

Contract for Electric Service 6/20/1973

Schedule Page: 326 Line No.: 2 Column: c

Contracts for electric service dated 10/3/1975, 5/3/1976 and 2/23/2016.

Schedule Page: 326 Line No.: 3 Column: c

Contract for electric service dated 1/7/1997.

Schedule Page: 326 Line No.: 4 Column: c

Contract for electric service dated 7/29/1996.

Schedule Page: 326 Line No.: 5 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 5 Column: c

Contract for Test and Excess Energy Purchase and Sale Agreement between South Carolina Electric & Gas Company and Columbia Energy LLC dated as of 1/17/2004.

Schedule Page: 326 Line No.: 6 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 6 Column: c

Contract for electric service dated 5/1/1984.

Schedule Page: 326 Line No.: 7 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 7 Column: c

Various agreements for purchased power from customers pursuant to the Company's PR-1 (Small Power Production, Cogeneration) Rate Schedule.

Schedule Page: 326 Line No.: 8 Column: c

Docket Nos. ER01-1043-000 and ER03-237-000.

Schedule Page: 326 Line No.: 8 Column: l

Barter arrangement for transmission ancillary services 1, 2, 5 and 6.

Schedule Page: 326 Line No.: 9 Column: a

Affiliated Company

Schedule Page: 326 Line No.: 9 Column: c

FERC Electric Rate Schedule No. 1, Schedule 8 Billing Format - Cost of Service Tariff Docket Nos. ER85-204-007 and ER85-603-005.

Schedule Page: 326 Line No.: 10 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 10 Column: c

FERC Electric Rate Schedule No. 1, Docket No. ER10-2712.

Schedule Page: 326 Line No.: 11 Column: b

OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute, Inc. (EEI) Master Power Purchase and Sale Agreement.

Schedule Page: 326 Line No.: 11 Column: c

Tariff No. 5, Docket No. ER12-2322.

Schedule Page: 326 Line No.: 12 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 12 Column: c

FERC Electric Tariff Volume No. 3, Docket No. ER14-1625.

Schedule Page: 326 Line No.: 13 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 13 Column: c

International Swaps and Derivatives Association (ISDA) Agreement effective 9/1/2005.

Schedule Page: 326 Line No.: 14 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 14 Column: c

Tariff #1, Docket No. ER10-2778

Schedule Page: 326.1 Line No.: 2 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 2 Column: c

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 6/1/2003.

Schedule Page: 326.1 Line No.: 3 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 3 Column: c

Tariff #4, Docket No. ER10-2881

Schedule Page: 326.1 Line No.: 4 Column: b

OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute, Inc. (EEI) Master Power Purchase and Sale Agreement.

Schedule Page: 326.1 Line No.: 4 Column: c

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2004.

Schedule Page: 326.1 Line No.: 5 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 5 Column: c

FERC Electric Rate Schedule No. 42.

Schedule Page: 326.1 Line No.: 6 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 6 Column: c

FERC Electric Rate Schedule No. 29.

Schedule Page: 326.1 Line No.: 7 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate docket number.

Schedule Page: 326.1 Line No.: 7 Column: c

SCPSC Docket No. 2016-182-E, Order No. 2016-373

Schedule Page: 326.1 Line No.: 8 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate docket number.

Schedule Page: 326.1 Line No.: 8 Column: c

SCPSC Docket No. 2015-363-E, Order No. 2015-788

Schedule Page: 326.1 Line No.: 10 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate docket number.

Schedule Page: 326.1 Line No.: 10 Column: c

SCPSC Docket No. 2015-54-E, Order No. 2015-512

Schedule Page: 326.1 Line No.: 11 Column: b

IU - Service from designated generating unit(s) with duration longer than one year but less than five years.

Schedule Page: 326.1 Line No.: 11 Column: c

Tariff #1, Docket No. ER10-1892

Schedule Page: 326.1 Line No.: 11 Column: l

Scheduling charges

Schedule Page: 326.1 Line No.: 12 Column: b

IF - Firm service with duration longer than one year but less than five years. Contract terminated on 12/31/2016.

Schedule Page: 326.1 Line No.: 12 Column: c

Tariff #4, Docket No. ER10-2881

Schedule Page: 326.1 Line No.: 13 Column: a

Termination requires a 4-year written notice by either party to terminate the agreement. Written notice for termination presented to Santee Cooper on 5/6/2016. The current effective date of termination is 5/6/2020.

Schedule Page: 326.1 Line No.: 13 Column: c

Contract for electric service dated 1/7/1997.

Schedule Page: 326.1 Line No.: 14 Column: b

EX - Exchanges of electricity.

Schedule Page: 326.1 Line No.: 14 Column: c

Electric service provided under SCE&G's OATT Schedules 4 and 9.

Schedule Page: 326.1 Line No.: 14 Column: h

Over delivery of energy by Columbia Energy, LLC

Schedule Page: 326.1 Line No.: 14 Column: i

Under delivery of energy by Columbia Energy, LLC

Schedule Page: 326.2 Line No.: 1 Column: l

Reflects amortization of previously deferred purchased power and capacity charges of $282,658 and $296,000 respectively per SCPSC Docket No. 2009-489-E.

Reflects the deferral of purchase power per SCPSC Docket No. 2009-489-E of($3,419,418).

Reflects the deferral of short-term capacity purchases from The Energy Authority, Inc. per SCPSC Docket Nos. 2008-230-E and 2012-218-E of ($37,200).

Reflects the deferral of capacity purchases from Columbia Energy, LLC and Southern Company Services, Inc. per SCPSC Docket No. 2013-276-E of ($4,822,104).

Reflects fuel expense of $25,938 for Company-owned fuel oil used by Columbia Energy LLC, for generation.

Reflects the deferral of purchase power of ($206,220) pursuant to SCPSC Docket No. 2015-54-E, under the Company's Distributed Energy Resources (DER) program.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Duke Energy Carolinas, LLC	Georgia Power Company	Duke Energy Progress, LLC	SFP
2				
3	Duke Energy Carolinas, LLC	Georgia Power Company	Duke Energy Carolinas, LLC	SFP
4				
5	Southern Company Services, Inc.	Georgia Power Company	Duke Energy Carolinas, LLC	NF
6				
7	Southern Company Services, Inc.	Duke Energy Carolinas, LLC	Georgia Power Company	NF
8				
9	The Energy Authority, Inc.	Georgia Power Company	South Carolina Public Service	
10			Authority	SFP
11				
12	South Carolina Public Service	South Carolina Public Service	Various	
13	Authority	Authority		FNO
14				
15	Southeastern Power Administration	Southeastern Power	Various	
16		Administration		FNO
17				
18	City of Orangeburg	South Carolina Electric & Gas	City of Orangeburg	
19		Company		FNO
20				
21	Town of Winnsboro	South Carolina Electric & Gas	Town of Winnsboro	
22		Company		FNO
23				
24	Central Electric Power Co-op	South Carolina Public Service	Central Electric Power Co-op	
25		Authority		FNO
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
T5.S7, S1, S2	SOCO	CPLE	153	2,400	2,352	1
						2
T5.S7, S1, S2	SOCO	DUK	306	4,000	3,920	3
						4
T5.S8, S1, S2	SOCO	DUK				5
						6
T5.S8, S1, S2	DUK	SOCO		1,552	1,518	7
						8
						9
T5.S7,S1, S2	SOCO	SC	123	2,921	2,863	10
						11
						12
T5, Attach H			655	308,326	299,346	13
						14
						15
T5, Attach H			216	32,499	31,363	16
						17
						18
T5, Attach H			1,596	868,750	843,447	19
						20
						21
T5, Attach H			73	40,512	39,717	22
						23
						24
T5, Attach H			67	27,370	26,832	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			3,189	**1,288,330**	**1,251,358**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
18,980		985	19,965	1
				2
37,960		1,970	39,930	3
				4
15		1	16	5
				6
12,369		669	13,038	7
				8
				9
14,973		852	15,825	10
				11
				12
1,748,934	13,887	95,360	1,858,181	13
				14
				15
591,400		68,332	659,732	16
				17
				18
4,254,064		565,543	4,819,607	19
				20
				21
198,429		25,861	224,290	22
				23
				24
178,360	770	9,731	188,861	25
				26
				27
				28
				29
				30
				31
				32
				33
				34
7,055,484	**14,657**	**769,304**	**7,839,445**	

Schedule Page: 328 Line No.: 1 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 1 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 1 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 3 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 3 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 3 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 5 Column: h
Non-firm hourly billing demand of 2.

Schedule Page: 328 Line No.: 5 Column: i
Customer reserved transmission service, but did not schedule service.

Schedule Page: 328 Line No.: 5 Column: j
Customer reserved transmission service, but did not schedule service.

Schedule Page: 328 Line No.: 5 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 7 Column: h
Non-firm hourly billing demand of 1,692.

Schedule Page: 328 Line No.: 7 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 7 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 7 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 10 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 10 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 10 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 13 Column: e
Also includes Rate Schedules S1, S2 and S4 of Tariff.

Schedule Page: 328 Line No.: 13 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 13 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 13 Column: l
Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.

Schedule Page: 328 Line No.: 13 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 13 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 16 Column: e
Also includes Rate Schedules S1, S2, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 16 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 16 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 16 Column: m
Sum of Ancillary Service 1, 2, 5 and 6 charges.

Schedule Page: 328 Line No.: 16 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 19 Column: e
Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 19 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 19 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 19 Column: m
Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 19 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 22 Column: e
Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

Schedule Page: 328 Line No.: 22 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 22 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 22 Column: m
Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 22 Column: n
Network transmission revenue.

Schedule Page: 328 Line No.: 25 Column: e
Also includes Rate Schedules S1, S2, and S4 of Tariff.

Schedule Page: 328 Line No.: 25 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 25 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 25 Column: l
Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.

Schedule Page: 328 Line No.: 25 Column: m
Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 25 Column: n
Network transmission revenue.

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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Carolinas	FNS	5,004	5,184	14,496	5,829	15,521	35,846
2	Santee Cooper	SFP	1,800		9,011		1,423	10,434
3	Southern Co Svcs, Inc	SFP	300,818		3,317,472		252,707	3,570,179
4	Adjustments						-1,081,034	-1,081,034
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		307,622	5,184	3,340,979	5,829	-811,383	2,535,425

Schedule Page: 332 Line No.: 1 Column: g

Scheduling, System Control and Dispatch	$	382
Reactive Supply and Voltage Control		1,823
Regulation and Frequency Response		347
Operating Reserve - Spinning		743
Operating Reserve - Supplement		743
Other - Direct Assignment Charges		11,483
Total	$	15,521

Schedule Page: 332 Line No.: 2 Column: g

Scheduling, System Control and Dispatch	$	406
Reactive Supply and Voltage Control		1,017
Total	$	1,423

Schedule Page: 332 Line No.: 3 Column: g

Scheduling, System Control and Dispatch	$	96,720
Reactive Supply and Voltage Control		132,000
Other - FERC Annual Charge Recovery		19,510
Other - Recovery of Attachment K Charge Factor		4,477
Total	$	252,707

Schedule Page: 332 Line No.: 4 Column: g

Columbia Energy LLC Reactive Supply and Voltage Control (RSV) to SCE&G	$ 488,000
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services, Inc. pursuant to SCPSC Docket No. 2013-276-E.	(1,378,779)
Southern Company Services, Inc. refund calculated on Transmission Service for 2015	(194,956)
Southern Company Services, Inc. surcharge calculated on Transmission Service for 2015	5,376
Duke Energy Carolinas refund calculated on Transmission Service for 2015	(675)
Total	($1,081,034)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	439,129
2	Nuclear Power Research Expenses	611,529
3	Other Experimental and General Research Expenses	947,217
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	259,291
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Other Business Expense	33,584
7	Transportation and Other Power Operated Equipment	27,637
8	Travel excluding Meals	3,148
9	Meals	43
10	Computer Hardware and Software Maintenance	67,888
11	Utilities	13,377
12	Telephone Resource Usage	42,371
13	Director Fees and Expenses	1,654,052
14	Outside Services	94,318
15	Computer Resource Usage, Hardware, Software	
16	and Network Services	105,692
17	Company Payroll	69,367
18	Aircraft Transportation	32,972
19	Depreciation, Amortization and Property Tax Charges	
20	billed from SCANA Services	13,528,020
21	Postage	5,300
22	Research and Development Grant Amortization	100,000
23	Miscellaneous	16,696
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
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44		
45		
46	TOTAL	18,051,631

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			5,412,654		5,412,654
2	Steam Production Plant	67,877,522				67,877,522
3	Nuclear Production Plant	19,505,763				19,505,763
4	Hydraulic Production Plant-Conventional	2,364,491				2,364,491
5	Hydraulic Production Plant-Pumped Storage	2,109,166				2,109,166
6	Other Production Plant	24,927,519				24,927,519
7	Transmission Plant	28,750,010				28,750,010
8	Distribution Plant	71,693,390				71,693,390
9	Regional Transmission and Market Operation					
10	General Plant	5,300,199				5,300,199
11	Common Plant-Electric	5,865,540		2,624,476		8,490,016
12	TOTAL	228,393,600		8,037,130		236,430,730

B. Basis for Amortization Charges

Electric Intangible Plant (Account 404) consists of the following:
Amortization of Saluda Hydro Project #516, Stevens Creek Project #2535, Neal Shoals Project #2315 and relicensing costs associated with V. C. Summer Nuclear Station. The charges were based on plant balances of Saluda - $793,257, Stevens Creek - $2,268,402 and Neal Shoals - $1,507,161. The associated costs of relicensing the V. C. Summer Nuclear Plant through 2042 is $8,564,832.

Amortization of a steam generator at a cogeneration facility over the contractual term of the facility. The amortization is based on a gross plant amount of $11,144,060.

Data processing software costs of $69,791,263 are being amortized over the expected life of the software application.

Common Plant - Electric (Account 404):
Amortization of data processing software of $139,438,034 over the expected life of the software application.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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49							
50							

Schedule Page: 336 Line No.: 12 Column: a

Method of Determination of Depreciation Charges:

The Annual Provisions for Depreciation of Property, with the exception of major construction, are based on straight line rates applied to the prior month ending plant balances. The Annual Provision for Depreciation of major construction projects, if any, is computed based on the number of days that the plant was in service.

In addition to Depreciation Provisions provided by the application of the rates reported on this schedule in 2015, the Company also recognized $3,491,910 of electric and $701,053 of common depreciation related to vehicles, as well as, $5,655,498 of electric and $2,884,232 of common amortization related to software over their expected useful lives using the straight line method. See allocation of Common Plant on pages 356.1 and 356.2.

The Company also recognized amortization of a steam generator at a cogeneration facility over the contractual term of the facility. The amortization was based on a gross plant amount of $11,144,060.

Schedule Page: 336 Line No.: 13 Column: a

The Company completed this schedule in its 2015 Form No. 1 filing; therefore, in accordance with Instruction No. 3, the Company will complete the full Section C again in its Form No. 1 filing for 2020. There are no changes to report for the information required in Columns C through G. The information required in Columns C through G is only recalculated during full depreciation studies.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	State assessment for the support of the				
2	Public Service Commission of South				
3	Carolina (SCPSC) and annual charges assessed				
4	by the Federal Energy Regulatory				
5	Commission (FERC).	5,164,078		5,164,078	
6					
7	Company labor, legal and miscellaneous				
8	expenses related to proceedings before the				
9	SCPSC.		35,979	35,979	
10					
11	Company labor, legal and miscellaneous				
12	expenses related to Dockets associated with				
13	Revisions and Updates for the Construction and				
14	Operation of a Nuclear Facility in				
15	Jenkinsville, SC before the SCPSC.		37,473	37,473	
16					
17					
18	Company labor, legal, consulting and				
19	miscellaneous expenses related to proceedings				
20	before the FERC.		7,370	7,370	
21					
22	Company labor, legal and miscellaneous				
23	expenses associated with the Distributed				
24	Energy Resources Program Act before the SCPSC				
25	Docket No. 2014-214-E.		-323	-323	
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,164,078	80,499	5,244,577	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
Electric	928	5,164,078					5
							6
							7
							8
Electric	928	35,979					9
							10
							11
							12
							13
							14
Electric	928	37,473					15
							16
							17
							18
							19
Electric	928	7,370					20
							21
							22
							23
							24
Electric	928	-323					25
							26
							27
							28
							29
							30
							31
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							44
							45
		5,244,577					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed Internally	
2	(1) Generation	EPRI Coordination
3		Technology Transfer
4	(2) Transmission	EPRI Coordination
5		Technology Transfer
6	(3) Distribution	EPRI Coordination
7		Technology Transfer
8	(6) Other	
9	Power Quality	EPRI Coordination
10		
11	B. Electric R,D and D Performed Externally	
12	(1) Research Support to EPRI	
13	Fossil Steam Plants and Combustion	
14	Turbines - Programs	Boiler and Turbine Steam and Cycle Chemistry
15		Combined Cycle HRSG and Balance of Plant
16		Generation Maintenance Applications Center
17		Operations Management & Technology
18		Coal Combustion Products - Envrionmental Issues
19		Fish Protection at Steam Electric Power Plants
20		Effluent Guidelines and Water Quality Management
21		Power Plant Multimedia Toxics Characterization
22		Air Quality Assessment of Ozone, Particulate Matter, Visibility and
23		Deposition
24	Nuclear Power - Programs	
25		Nuclear Power
26		Steam Turbines, Generators and Balance-of-Plant
27	Transmission and Substation - Programs	
28		Structure and Sub-Grade Corrosion Management
29		Lightning Performance and Grounding of Transmission Lines
30		Line Design Tools and Practices for Construction and Maintenance
31		Polymer and Composite Overhead Transmission Insulators
32		Overhead Line Ratings and Increased Power Flow
33		High Temperature Operation of Overhead Lines
34		Technology Transfer for Underground Transmission
35		Transformer Life Management
36		Substation Physical Security and Intentional Electromagnetic
37		Interference (IEMI)
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
89,642		Various	89,642		2
403		Various	403		3
12,282		Various	12,282		4
8,542		Various	8,542		5
8,862		Various	8,862		6
12,380			12,380		7
					8
3,577		Various	3,577		9
					10
					11
					12
					13
	30,609	930.2	30,609		14
	80,505	930.2	80,505		15
	17,441	930.2	17,441		16
	48,352	930.2	48,352		17
	56,416	930.2	56,416		18
	68,252	930.2	68,252		19
	63,992	930.2	63,992		20
	70,424	930.2	70,424		21
					22
	72,414	930.2	72,414		23
					24
	611,529	930.2	611,529		25
	54,889	517	54,889		26
					27
	10,294	930.2	10,294		28
	18,026	930.2	18,026		29
	14,486	930.2	14,486		30
	16,733	930.2	16,733		31
	11,499	930.2	11,499		32
	13,141	930.2	13,141		33
	9,252	930.2	9,252		34
	35,715	930.2	35,715		35
					36
	12,143	930.2	12,143		37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Energy Storage and Distributed Generation -	
2	Programs	
3		Strategic Intelligence and Analysis
4	Cyber Security - Programs	
5		Cyber Security and Privacy
6	Fossil Steam Plants and Combustion Turbines -	
7	Supplemental Projects	
8		Plant Decomissioning and Site Closure Interest Group
9	Nuclear - Supplemental Projects	
10		SGMP - Steam Generator Management Program
11		WRTC - Welding & Repair Technology Center
12		FRP - Fuel Reliability Program (QA)
13		Fuel Works / Cask Loader Users Group
14		NDE - Nondestructive Evaluation Applications and Technology (QA)
15		NMAC - Nuclear Maintenance Applications Center
16		Cable Program
17		Nuclear Plant Performance Programs (HXPUG, SWAP, P2EP)
18		SQURTS – Seismic Qualification Reporting and Testing Standardization (QA)
19		Standardized Task Evaluations for Portable Qualifications (STE)
20		Submergence Qualification for Medium-Voltage Cable (QA)
21		CHECWORKS Users Group (CHUG)
22		BPIG - Buried Pipe Integrity Group
23		GOTHIC Advisory Group (QA)
24		HRA Calculator User Group (QA)
25		MAAP Users Group
26		Integrated Risk Technologies Users Group
27		External Data Hazards Collection
28		SMART chemWORKS User Group - Maintenance and Support
29		Fault Tree Reliability Evaluation eXpert (FTREX)
30		Advanced Nuclear Technology (ANT) New Plant Deployment
31		
32	Transmission - Supplemental Projects	
33		Electromagnetic Pulse (EMP) Grid Resilience: Transmission
34		Vulnerability and Mitigation
35	Cyber Security Projects	
36		Cybersecurity Capability Maturity Model Assessment
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
	14,418	930.2	14,418		3
					4
	101,675	930.2	101,675		5
					6
					7
	6,205	921	6,205		8
					9
	68,833	524	68,833		10
	16,085	524	16,085		11
	107,438	524	107,438		12
	12,000	107	12,000		13
	38,667	524	38,667		14
	11,833	524	11,833		15
	2,333	524	2,333		16
	6,400	524	6,400		17
	20,000	524	20,000		18
	11,941	524	11,941		19
	10,000	524	10,000		20
	8,000	524	8,000		21
	10,000	524	10,000		22
	8,000	524	8,000		23
	6,667	524	6,667		24
	8,667	182.3	8,667		25
	21,800	524	21,800		26
	10,000	182.3	10,000		27
	20,000	524	20,000		28
	2,667	524	2,667		29
	137,500	107	137,500		30
					31
					32
					33
	24,352	921	24,352		34
					35
	24,930	930.2	24,930		36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	(4) Research Support to Others (Classify):	
2	Clemson University Electric	
3	Power Research Association	
4	National Electric Energy Testing and	
5	Research Applications Center	
6	Southeast Coastal Wind Coalition	
7	South Carolina Clean Energy	
8	Business Alliance	
9	South Carolina Biomass Council	
10	Smart Electric Power Alliance	
11	Marketing Research	
12		
13	Total Cost Incurred	
14		
15		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
	30,000	930.2	30,000		3
					4
	104,000	930.2	104,000		5
	5,000	921	5,000		6
					7
	4,000	921	4,000		8
	50	921	50		9
	21,800	921	21,800		10
	22,500	930.2	22,500		11
					12
135,688	2,213,873		2,349,561		13
					14
					15
					16
					17
					18
					19
					20
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Schedule Page: 352.2 Line No.: 15 Column: a

In addition to the activity reported herein, the Company has also claimed significant tax-defined research and experimentation deductions under Internal Revenue Code Section 174 and credits under Internal Revenue Code Section 41 related to the design and construction activities of V.C. Summer Nuclear Station Units 2 and 3. See Note 5 to the financial statements for additional details.

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	46,571,491		
4	Transmission	4,529,972		
5	Regional Market			
6	Distribution	6,087,065		
7	Customer Accounts	18,166,885		
8	Customer Service and Informational	2,540,907		
9	Sales	1,013,772		
10	Administrative and General	30,637,259		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	109,547,351		
12	Maintenance			
13	Production	25,921,963		
14	Transmission	2,509,369		
15	Regional Market			
16	Distribution	11,590,936		
17	Administrative and General	1,807,563		
18	TOTAL Maintenance (Total of lines 13 thru 17)	41,829,831		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	72,493,454		
21	Transmission (Enter Total of lines 4 and 14)	7,039,341		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	17,678,001		
24	Customer Accounts (Transcribe from line 7)	18,166,885		
25	Customer Service and Informational (Transcribe from line 8)	2,540,907		
26	Sales (Transcribe from line 9)	1,013,772		
27	Administrative and General (Enter Total of lines 10 and 17)	32,444,822		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	151,377,182	19,068,550	170,445,732
29	Gas			
30	Operation			
31	Production-Manufactured Gas	132,156		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	10,777,013		
37	Customer Accounts	3,571,550		
38	Customer Service and Informational	635,965		
39	Sales	2,921,326		
40	Administrative and General	5,399,054		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	23,437,064		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	5,726		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,729,681		
49	Administrative and General	173,418		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,908,825		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	132,156		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)	5,726		
57	Distribution (Lines 36 and 48)	14,506,694		
58	Customer Accounts (Line 37)	3,571,550		
59	Customer Service and Informational (Line 38)	635,965		
60	Sales (Line 39)	2,921,326		
61	Administrative and General (Lines 40 and 49)	5,572,472		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	27,345,889	3,323,501	30,669,390
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	178,723,071	22,392,051	201,115,122
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	79,263,254	7,395,922	86,659,176
69	Gas Plant	6,073,554	1,560,502	7,634,056
70	Other (provide details in footnote):		1,409,825	1,409,825
71	TOTAL Construction (Total of lines 68 thru 70)	85,336,808	10,366,249	95,703,057
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,684,555	1,269,990	4,954,545
74	Gas Plant	687,944	100,967	788,911
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,372,499	1,370,957	5,743,456
77	Other Accounts (Specify, provide details in footnote):			
78	Non Utility Property		1,005,326	1,005,326
79	Non Operating Expenses	3,662,722	647,525	4,310,247
80	Other Work in Process	888,371	396,985	1,285,356
81	Other Balance Sheet Payroll	8,847,315	905,108	9,752,423
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	13,398,408	2,954,944	16,353,352
96	TOTAL SALARIES AND WAGES	281,830,786	37,084,201	318,914,987

Schedule Page: 354 Line No.: 70 Column: d

Common Plant

Schedule Page: 354 Line No.: 81 Column: d

DSM Deferrals, Regulatory Assets, PSI Accounts, Stores Expense and Temporary Facilities.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

(1) and (2) See pages 356.1 and 356.2

(3) Common Utility Plant Expenses are not segregated, but charged to utility departments on a functional basis. South Carolina Electric & Gas Company owns all of the Common Utility Plant of SCANA Corporation. Other subsidiaries of SCANA Corporation that benefit from the use of Common Utility Plant are charged directly by South Carolina Electric & Gas Company for their proportionate share of the related expenses.

(4) July 24, 1948

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Utility Plant In Service	Balance End of Year
118-603 Misc Intangible Plant	$139,438,034
118-689 Land and Land Rights	18,841,171
118-690 Structures and Improvements	179,913,733
118-691 Office Furniture and Equipment	12,085,170
118-692 Transportation Equipment	6,592,862
118-693 Stores Equipment	21,011
118-694 Tools, Shop and Garage Equipment	2,119,934
118-695 Laboratory Equipment	151,693
118-696 Power-Operated Equipment	4,579,339
118-697 Communication Equipment	8,158,322
118-698 Miscellaneous Equipment	6,569,743
118-699 ARC Common Gen Plant	673,415
Total	$379,144,427

Note: Common Plant in service consists of land and buildings devoted jointly to all utility operations, such as general office buildings, storerooms and repair shops and equipment therein. Also, software and transportation equipment used jointly is thus classifed.

Construction Work in Progress - Common Utility Plant

Description of Project	Balance End of Year
CIS Modernization	$ 7,744,681
CIS Infrastructure	4,559,348
Other Projects < $500K	993,324
Total	$ 13,297,353

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Plant in Service and Depreciation Reserve
Allocable to Utility Departments

Common Utility	Total (a)	Electric (b)	Gas (c)
Plant Allocable to Utility Departments (1)	$379,144,427	$345,665,974	$33,478,453
Less:			
Common Depreciable Reserve Allocable to Utility Departments (2)	182,626,174	166,500,283	16,125,891
Net Common Plant Allocable to Utility Departments	$196,518,253	$179,165,691	$17,352,562

(1) This allocation is based on functional use by Departments.
Percentage:Electric 91.17% and Gas 8.83%

(2) This allocation is based on functional use by Departments of common depreciable property.
Percentages are the same as in note (1).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
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43					
44					
45					
46	TOTAL				

Schedule Page: 397 Line No.: 2 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 2 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 2 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 2 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 3 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 4 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 5 Column: e
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: b
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: c
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: d
No activity during reported period.
Schedule Page: 397 Line No.: 6 Column: e
No activity during reported period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			97,508	22,702	MW	108,879
2	Reactive Supply and Voltage			622,840	22,702	MW	289,366
3	Regulation and Frequency Response			347	1,719	MW	79,746
4	Energy Imbalance	180	MWH	5,829	479	MWH	14,657
5	Operating Reserve - Spinning			743	1,935	MW	128,683
6	Operating Reserve - Supplement			743	1,935	MW	187,102
7	Other			-1,533,564	1,969	MWH	38,129
8	Total (Lines 1 thru 7)	180		-805,554	53,441		846,562

Name of Respondent South Carolina Electric & Gas Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2016/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 1 Column: b

Reference footnote Line No.1, Column D for detail on number of units.

Schedule Page: 398 Line No.: 1 Column: c

Reference footnote Line No.1, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 1 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 1	.055781	% Load Ratio Share	$ 382
Santee Cooper OATT Rate Schedule 1	100 MW/1800 MWH	MW, MWH	406
Southern Company Services, Inc. OATT Rate Schedule 1	100 MW/300,818 MWH	MW, MWH	96,720
Total			$ 97,508

Schedule Page: 398 Line No.: 2 Column: b

Reference footnote Line No.2, Column D for detail on number of units.

Schedule Page: 398 Line No.: 2 Column: c

Reference footnote Line No.2, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 2 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 2	.055781	% Load Ratio Share	$ 1,823
Santee Cooper OATT Rate Schedule 2	100 MW/1800 MWH	MW, MWH	1,017
Southern Company Services, Inc. OATT Rate Schedule 2	100 MW/300,818 MWH	MW, MWH	132,000
Columbia Energy LLC Reactive Supply and Voltage Control to SCE&G	Flate Rate	Flat Rate	488,000
Total			$ 622,840

Schedule Page: 398 Line No.: 3 Column: b

Reference footnote Line No.3, Column D for detail on number of units.

Schedule Page: 398 Line No.: 3 Column: c

Reference footnote Line No.3, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 3 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 3	.055781	% Load Ratio Share	$ 347

Schedule Page: 398 Line No.: 4 Column: b

Reference footnote Line No.4, Column D for detail on number of units.

Schedule Page: 398 Line No.: 4 Column: c

Reference footnote Line No.4, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 4 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 4	180	MWH	$ 5,829

Schedule Page: 398 Line No.: 5 Column: b

Reference footnote Line No.5, Column D for detail on number of units.

Schedule Page: 398 Line No.: 5 Column: c

Reference footnote Line No.5, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 5 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 5	.055781	% Load Ratio Share	$ 743

Schedule Page: 398 Line No.: 6 Column: b

Reference footnote Line No.6, Column D for detail on number of units.

Schedule Page: 398 Line No.: 6 Column: c

Reference footnote Line No.6, Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 6 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 6	.055781	% Load Ratio Share	$ 743

Schedule Page: 398 Line No.: 7 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Direct Assignment Charges and Other Miscellaneous Adjustments			$ 11,483
Duke Energy Carolinas, LLC refund calculated on Transmission Service for 2015.			(675)
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services, Inc. pursuant to SCPSC Docket No. 2013-276-E			(1,378,779)
Southern Company Services, Inc. refund calculated on Transmission Service for 2015.			(194,956)
Southern Company Services, Inc. surcharge calculated on Transmission Service for 2015.			5,376
Southern Company Services, Inc. FERC Annual Charge Recovery			19,510
Southern Company Services, Inc. Recovery of Attachment K Charge Factor			4,477
Total			($1,533,564)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2016/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 7 Column: e

Generator Imbalance breakdown by MWH:

Net Band 1	Over Delivered	Under Delivered
201	474	1,294

Schedule Page: 398 Line No.: 7 Column: g

Generator Imbalance breakdown by dollar amount:

Net Band 1	Over Delivered	Under Delivered*
$6,553	($12,128)	$43,704

* Reported value for Under Deliveries is net of Generator Imbalance Penalties credited to users of the transmission system.

Schedule Page: 398 Line No.: 8 Column: e

Total is not meaningful due to summation of dissimilar units of measure.

Schedule Page: 398 Line No.: 8 Column: g

Ancillary Services revenue reported on this schedule is reported as necessary in other supporting schedules within this Form 1 filing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,567	19	800	4,307	260				
2	February	4,401	10	800	4,150	251				
3	March	3,168	22	800	2,980	188				
4	Total for Quarter 1				11,437	699				
5	April	3,592	29	1700	3,400	192				
6	May	3,978	31	1700	3,778	200				
7	June	4,903	22	1700	4,655	248				
8	Total for Quarter 2				11,833	640				
9	July	5,266	26	1700	4,858	255			153	
10	August	4,804	12	1700	4,572	232				
11	September	4,609	8	1700	4,380	229				
12	Total for Quarter 3				13,810	716			153	
13	October	3,614	3	1600	3,435	179				
14	November	3,698	21	800	3,497	201				
15	December	3,823	16	800	3,601	222				
16	Total for Quarter 4				10,533	602				
17	Total Year to Date/Year				47,613	2,657			153	

Schedule Page: 400 Line No.: 1 Column: d

All times shown are in Hour Ending (HE) format.

Schedule Page: 400 Line No.: 1 Column: e

The Company utilizes grandfathered service for its retail customers and has not executed a network integration transmission service agreement under the OATT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	22,524,213
3	Steam	6,993,191			
4	Nuclear	5,772,294	23	Requirements Sales for Resale (See instruction 4, page 311.)	928,209
5	Hydro-Conventional	250,162			
6	Hydro-Pumped Storage	519,448	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	18,772
7	Other	6,788,765			
8	Less Energy for Pumping	721,050	25	Energy Furnished Without Charge	8
9	Net Generation (Enter Total of lines 3 through 8)	19,602,810	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	139,281
10	Purchases	4,978,837	27	Total Energy Losses	981,150
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	24,591,633
12	Received	473			
13	Delivered	1,361			
14	Net Exchanges (Line 12 minus line 13)	-888			
15	Transmission For Other (Wheeling)				
16	Received	379,068			
17	Delivered	368,194			
18	Net Transmission for Other (Line 16 minus line 17)	10,874			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	24,591,633			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,146,501		4,409	19	800
30	February	1,909,532		4,221	10	800
31	March	1,734,646		3,129	16	1700
32	April	1,703,344		3,602	29	1700
33	May	1,946,291		3,799	31	1700
34	June	2,319,390	83	4,513	22	1700
35	July	2,627,320	2,934	4,807	28	1700
36	August	2,551,426	208	4,660	15	1700
37	September	2,168,613	769	4,249	9	1600
38	October	1,771,592		3,429	3	1600
39	November	1,760,843		3,406	21	800
40	December	1,952,135	15,614	3,900	16	800
41	TOTAL	24,591,633	19,608			

Schedule Page: 401 Line No.: 16 Column: b

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from SCE&G's system. The MWH supporting these transactions are included in SCE&G's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,288,330	1,251,358
Page 401a	379,068	368,194
Difference	909,262	883,164

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 19	868,750	843,447
Page 329 line 22	40,512	39,717
Total	909,262	883,164

Schedule Page: 401 Line No.: 17 Column: b

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from SCE&G's system. The MWH supporting these transactions are included in SCE&G's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,288,330	1,251,358
Page 401a	379,068	368,194
Difference	909,262	883,164

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 19	868,750	843,447
Page 329 line 22	40,512	39,717
Total	909,262	883,164

Schedule Page: 401 Line No.: 29 Column: f

All times shown in column (f) are in Hour Ending (HE) format.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *V.C. Summer (2/3rds)* (b)			Plant Name: *Urquhart* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	PWR			Conventional		
3	Year Originally Constructed	1984			1953		
4	Year Last Unit was Installed	1984			1955		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	686.40			100.00		
6	Net Peak Demand on Plant - MW (60 minutes)	665			98		
7	Plant Hours Connected to Load	8784			2901		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	661			96		
10	When Limited by Condenser Water	647			95		
11	Average Number of Employees	677			62		
12	Net Generation, Exclusive of Plant Use - KWh	5772294000			197299000		
13	Cost of Plant: Land and Land Rights	880612			2614196		
14	Structures and Improvements	305981573			16807159		
15	Equipment Costs	900444236			101792778		
16	Asset Retirement Costs	22893826			11409896		
17	Total Cost	1230200247			132624029		
18	Cost per KW of Installed Capacity (line 17/5) Including	1792.2498			1326.2403		
19	Production Expenses: Oper, Supv, & Engr	12421296			55541		
20	Fuel	56467219			5571573		
21	Coolants and Water (Nuclear Plants Only)	2876256			0		
22	Steam Expenses	6316647			229936		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1566158			196846		
26	Misc Steam (or Nuclear) Power Expenses	41091216			834312		
27	Rents	0			0		
28	Allowances	0			-10490		
29	Maintenance Supervision and Engineering	15200712			25350		
30	Maintenance of Structures	2738627			17785		
31	Maintenance of Boiler (or reactor) Plant	3069010			141313		
32	Maintenance of Electric Plant	2500132			2540125		
33	Maintenance of Misc Steam (or Nuclear) Plant	10319397			569511		
34	Total Production Expenses	154566670			10171802		
35	Expenses per Net KWh	0.0268			0.0516		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear			Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Grams			Barrels	MCF	
38	Quantity (Units) of Fuel Burned	905902	0	0	0	2060315	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	63786	0	0	0	1031	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	83.064	2.705	0.000
41	Average Cost of Fuel per Unit Burned	62.330	0.000	0.000	0.000	2.705	0.000
42	Average Cost of Fuel Burned per Million BTU	0.977	0.000	0.000	0.000	2.623	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.028	0.000
44	Average BTU per KWh Net Generation	10011.000	0.000	0.000	0.000	10770.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Wateree* (d)	Plant Name: *McMeekin* (e)	Plant Name: *Canadys* (f)	Line No.
Steam	Steam	Steam	1
Outdoor-Boiler	Semi-Outdoor	Outdoor-Boiler	2
1970	1958	1962	3
1971	1958	1967	4
771.80	293.76	0.00	5
690	259	0	6
7984	7529	0	7
0	0	0	8
684	250	0	9
684	250	0	10
96	51	1	11
3390308000	910074000	0	12
2119622	15668	5598726	13
136209568	22556971	0	14
757072301	166702890	0	15
-20786500	4407234	0	16
874614991	193682763	5598726	17
1133.2146	659.3231	0	18
1734179	438301	0	19
124322292	21063590	0	20
0	0	0	21
716278	1920123	0	22
0	0	0	23
0	0	0	24
2796001	836863	0	25
1700640	1082626	0	26
0	4500	0	27
-45259	-40734	0	28
9420	25143	0	29
938488	233913	0	30
7977912	938546	0	31
669000	2518769	0	32
690871	1269616	0	33
141509822	30291256	0	34
0.0417	0.0333	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Coal	Gas	Oil				36
Tons	Barrels		Tons	MCF	Barrels				37
1396728	27383	0	32080	8356819	986	0	0	0	38
12424	137191	0	12263	1031	137191	0	0	0	39
83.729	66.519	0.000	0.000	2.281	0.000	0.000	0.000	0.000	40
85.892	65.439	0.000	58.396	2.281	137.538	0.000	0.000	0.000	41
3.457	11.357	0.000	2.451	2.214	23.870	0.000	0.000	0.000	42
0.036	0.000	0.000	0.023	0.000	0.000	0.000	0.000	0.000	43
10191.000	0.000	0.000	10254.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Cope* (b)			Plant Name: *Parr #1 & 2* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Package		
3	Year Originally Constructed	1996			1970		
4	Year Last Unit was Installed	1996			1970		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	417.36			39.10		
6	Net Peak Demand on Plant - MW (60 minutes)	420			30		
7	Plant Hours Connected to Load	6067			214		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	415			34		
10	When Limited by Condenser Water	415			27		
11	Average Number of Employees	70			0		
12	Net Generation, Exclusive of Plant Use - KWh	1974564000			3009000		
13	Cost of Plant: Land and Land Rights	3212442			9803		
14	Structures and Improvements	82529641			374377		
15	Equipment Costs	459637360			7315937		
16	Asset Retirement Costs	2480639			0		
17	Total Cost	547860082			7700117		
18	Cost per KW of Installed Capacity (line 17/5) Including	1312.6799			196.9339		
19	Production Expenses: Oper, Supv, & Engr	152112			0		
20	Fuel	65329344			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4400			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2232415			0		
26	Misc Steam (or Nuclear) Power Expenses	2136590			0		
27	Rents	0			0		
28	Allowances	-31133			0		
29	Maintenance Supervision and Engineering	29559			0		
30	Maintenance of Structures	178632			0		
31	Maintenance of Boiler (or reactor) Plant	3326394			0		
32	Maintenance of Electric Plant	246148			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	2643628			0		
34	Total Production Expenses	76248089			0		
35	Expenses per Net KWh	0.0386			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas	Oil			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	MCF	Barrels			
38	Quantity (Units) of Fuel Burned	744179	185321	7424	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12263	1031	137191	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	75.855	2.894	67.824	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	81.712	2.894	74.706	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.332	2.806	12.965	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9367.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Parr #3 & 4* (d)	Plant Name: *Parr Combined* (e)	Plant Name: *Hagood #4* (f)	Line No.
Gas Turbine		Gas Turbine	1
Package		Package	2
1971		1991	3
1971		1991	4
44.54	83.64	121.89	5
36	66	94	6
208	422	246	7
0	0	0	8
39	0	99	9
33	0	88	10
0	2	0	11
4323000	7332000	15325000	12
6047	15850	96047	13
515189	889566	3508613	14
4228943	11544880	34432016	15
0	0	0	16
4750179	12450296	38036676	17
106.6497	148.8558	312.0574	18
0	50211	0	19
0	486644	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	268801	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	1773	0	29
0	2879	0	30
0	0	0	31
0	321162	0	32
0	0	0	33
0	1131470	0	34
0.0000	0.1543	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	121087	332	0	0	0	0	38
0	0	0	1028	137191	0	0	0	0	39
0.000	0.000	0.000	3.672	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.672	127.352	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.571	22.102	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.061	0.464	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Hagood #5* (b)			Plant Name: *Hagood #6* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	2000			1981		
4	Year Last Unit was Installed	2000			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	27.40			27.94		
6	Net Peak Demand on Plant - MW (60 minutes)	22			23		
7	Plant Hours Connected to Load	401			403		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	21			21		
10	When Limited by Condenser Water	18			20		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	6234000			6748000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	350422			683139		
15	Equipment Costs	7472432			9599220		
16	Asset Retirement Costs	0			0		
17	Total Cost	7822854			10282359		
18	Cost per KW of Installed Capacity (line 17/5) Including	285.5056			368.0157		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Hagood Combined* (d)	Plant Name: *Hardeeville Peaking* (e)	Plant Name: *Urquhart #1 Peaking* (f)	Line No.
	Gas Turbine	Gas Turbine	1
	Package	Package	2
	1968	1969	3
	1968	1969	4
177.23	16.32	19.64	5
139	0	13	6
1050	0	13	7
0	0	0	8
0	9	16	9
0	9	13	10
9	0	0	11
28307000	0	43000	12
96047	5261	0	13
4542174	57556	505802	14
51503668	3553212	2285871	15
-5340517	0	0	16
50801372	3616029	2791673	17
286.6409	221.5704	142.1422	18
12339	377	0	19
1900787	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
470331	86494	0	25
0	0	0	26
0	0	0	27
-1187	0	0	28
36286	181	0	29
174623	1071	0	30
0	0	0	31
109782	38897	0	32
0	0	0	33
2702961	127020	0	34
0.0955	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Oil								36
MCF	Barrels								37
278566	6914	0	0	0	0	0	0	0	38
1030	137191	0	0	0	0	0	0	0	39
3.924	46.877	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.924	116.956	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.811	20.298	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.044	0.235	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Urquhart #2 Peaking* (b)			Plant Name: *Urquhart #3 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	16.32			16.32		
6	Net Peak Demand on Plant - MW (60 minutes)	14			8		
7	Plant Hours Connected to Load	27			8		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	17			15		
10	When Limited by Condenser Water	14			12		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	102000			27000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	403946			392049		
15	Equipment Costs	1987711			2522079		
16	Asset Retirement Costs	0			0		
17	Total Cost	2391657			2914128		
18	Cost per KW of Installed Capacity (line 17/5) Including	146.5476			178.5618		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Urquhart #4 Peaking* (d)			Plant Name: *Urquhart Comb 1-4* (e)			Plant Name: *Urquhart Comb Cycle* (f)			Line No.
Gas Turbine						Combined Cycle			1
Package						Package			2
1999						2002			3
1999						2002			4
58.90			111.18			547.80			5
46			81			470			6
630			678			10870			7
0			0			0			8
49			0			484			9
48			0			458			10
0			3			0			11
23196000			23368000			1941305000			12
0			0			0			13
639892			1941689			4752426			14
24002835			30798496			262816309			15
0			0			0			16
24642727			32740185			267568735			17
418.3825			294.4791			488.4424			18
0			28276			516674			19
0			752471			51937644			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			72555			2723374			25
0			0			0			26
0			0			0			27
0			0			3			28
0			127			4184			29
0			944			357915			30
0			0			0			31
0			1165362			13198754			32
0			0			0			33
0			2019735			68738548			34
0.0000			0.0864			0.0354			35
			Gas	Oil		Gas	Oil		36
			MCF	Barrels		MCF	Barrels		37
0	0	0	232483	475	0	14991935	1462	0	38
0	0	0	1031	137191	0	1031	137191	0	39
0.000	0.000	0.000	3.025	0.000	0.000	3.455	0.000	0.000	40
0.000	0.000	0.000	3.025	104.555	0.000	3.455	111.601	0.000	41
0.000	0.000	0.000	2.933	18.146	0.000	3.351	19.368	0.000	42
0.000	0.000	0.000	0.030	0.414	0.000	0.027	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coit #1 Peaking* (b)			Plant Name: *Coit #2 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.64			19.64		
6	Net Peak Demand on Plant - MW (60 minutes)	18			12		
7	Plant Hours Connected to Load	25			20		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	18			18		
10	When Limited by Condenser Water	14			12		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	246000			124000		
13	Cost of Plant: Land and Land Rights	36462			27297		
14	Structures and Improvements	98438			83439		
15	Equipment Costs	3430228			2558279		
16	Asset Retirement Costs	0			0		
17	Total Cost	3565128			2669015		
18	Cost per KW of Installed Capacity (line 17/5) Including	181.5238			135.8969		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Coit Combined* (d)	Plant Name: *Williams #1 Peaking* (e)	Plant Name: *Williams #2 Peaking* (f)	Line No.
	Gas Turbine	Gas Turbine	1
	Package	Package	2
	1972	1972	3
	1972	1972	4
39.28	27.00	27.00	5
30	26	22	6
45	22	23	7
0	0	0	8
0	26	26	9
0	20	20	10
0	0	0	11
370000	261000	230000	12
63759	0	0	13
181877	573403	40292	14
5988507	3272620	3716000	15
0	0	0	16
6234143	3846023	3756292	17
158.7104	142.4453	139.1219	18
0	0	0	19
41492	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
20499	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
198	0	0	29
0	0	0	30
0	0	0	31
155448	0	0	32
0	0	0	33
217637	0	0	34
0.5882	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Oil								36
MCF	Barrels								37
6997	130571	0	0	0	0	0	0	0	38
1029	137191	0	0	0	0	0	0	0	39
3.680	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.680	120.746	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.575	20.955	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.077	0.464	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Williams Combined* (b)			Plant Name: *Boeing* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Solar Photovoltaic		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)				Full-Outdoor		
3	Year Originally Constructed				2011		
4	Year Last Unit was Installed				2011		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	54.00			2.60		
6	Net Peak Demand on Plant - MW (60 minutes)	48			0		
7	Plant Hours Connected to Load	45			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	491000			0		
13	Cost of Plant: Land and Land Rights	0			339		
14	Structures and Improvements	613695			117179		
15	Equipment Costs	6988620			9245463		
16	Asset Retirement Costs	0			0		
17	Total Cost	7602315			9362981		
18	Cost per KW of Installed Capacity (line 17/5) Including	140.7836			3601.1465		
19	Production Expenses: Oper, Supv, & Engr	377			0		
20	Fuel	49849			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	115335			27303		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	12			0		
29	Maintenance Supervision and Engineering	181			0		
30	Maintenance of Structures	6356			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	65973			57118		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	238083			84421		
35	Expenses per Net KWh	0.4849			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Barrels				
38	Quantity (Units) of Fuel Burned	10393	311	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1030	137191	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.743	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.743	79.288	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.663	13.760	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.069	0.033	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Kapstone Generator* (d)	Plant Name: *Jasper* (e)	Plant Name: *Major Maint. Accrual* (f)	Line No.
Steam	Combined Cycle		1
Outdoor - Boiler	Package		2
1999	2004		3
1999	2004		4
99.31	1001.70	0.00	5
88	933	0	6
8452	5907	0	7
0	0	0	8
85	924	0	9
85	852	0	10
0	34	0	11
520913148	4784260000	0	12
0	2737068	0	13
0	28193762	0	14
11144060	476934176	0	15
0	0	0	16
11144060	507865006	0	17
112.2149	507.0031	0	18
0	655313	0	19
24722360	110393411	0	20
0	0	0	21
13760629	0	0	22
0	0	0	23
0	0	0	24
0	2754475	-414	25
0	6167	0	26
0	0	0	27
0	-8944	0	28
0	304289	0	29
0	2049	0	30
0	-462	-50324	31
0	6123821	-1243285	32
0	0	-655981	33
38482989	120230119	-1950004	34
0.0739	0.0251	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	34629551	716	0	0	0	0	38
0	0	0	1032	137191	0	0	0	0	39
0.000	0.000	0.000	3.179	84.293	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.179	105.794	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.081	18.361	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.023	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: f

In December 2012, the Company retired the 90MW Unit 1 at Canadys Station. In November 2013, the Company retired the remaining units, Unit 2 (115MW) and Unit 3 (180MW).

Schedule Page: 402 Line No.: 1 Column: b

SCE&G's portion (two-thirds) of jointly owned plant.

Instruction No. 12 - V. C. Summer Nuclear Station

(a) Nuclear fuel amortization, which is included in Production Expenses, is recorded using the units-of-production method. Normal operation and maintenance costs are charged to expenses as incurred with appropriate application of the accrual method of accounting. Pursuant to an order issued by the South Carolina Public Service Commission, estimated refueling outage operation and maintenance costs for the five outages scheduled Spring 2014 through Spring 2020 are being accrued over the 90 month period (January 2013 through June 2020) covered by these outages.

(b) Cost is recorded for nuclear fuel on the batch basis. At reload, the number of new assemblies required to complete the core requirement of 157 assemblies is designated as the new batch. All costs for this new batch are reported according to classification of component by batch number. Each batch consists of costs for U308, conversion, enrichment, fabrication, and allowance for funds used during construction.

(c) The V. C. Summer Nuclear Station is a Westinghouse PWR Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy tube cladding. The equilibrium cycle has approximately 65.5 metric tons of Uranium metal with a nominal U-235 enrichment of 4.6% to 4.8%. The reactor is licensed to allow operation of 2900 MWt.

Schedule Page: 403 Line No.: 5 Column: f

There are no remaining units in service. Therefore, no installed capacity is being reported for this plant.

Schedule Page: 403 Line No.: 18 Column: f

There are no remaining units in service and the only remaining cost (asset value) is land. Therefore, no "cost per KW installed capacity" is being reported for this plant.

Schedule Page: 403.1 Line No.: 2 Column: e

Parr Steam Plant functions in a combined cycle operation with four gas turbine peaking units and two heat recovery boilers. Production expenses and fuel data are for the entire operation. See column (e), lines 19-44 for combined data on Parr units.

Schedule Page: 402.1 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: d

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: e

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: f

Employees not specifically assigned to individual units.

Schedule Page: 402.2 Line No.: 11 Column: b

Employees not specifically assigned to individual units.

Schedule Page: 402.2 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: e
Unattended-automatic.

Schedule Page: 403.2 Line No.: 11 Column: f
Employees not specifically assigned to individual units.

Schedule Page: 402.3 Line No.: 11 Column: b
Employees not specifically assigned to individual units.

Schedule Page: 402.3 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: e
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: f
Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: b
Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: e
Unattended-automatic.

Schedule Page: 403.4 Line No.: 11 Column: f
Unattended-automatic.

Schedule Page: 402.5 Line No.: -1 Column: c
This is a rooftop mounted solar electric generator that provides electricity exclusively for use by a large industrial customer. None of the output flows onto the grid.

Schedule Page: 403.5 Line No.: -1 Column: f
The major maintenance accrual represents an SCPSC approved (SCPSC Docket No. 2009-489-E) annual accrual of $18.4 million. The Company is allowed to collect $18.4 million through retail electric rates to offset expenditures relating to certain turbine maintenance. Under this mechanism, the Company records an annual expense accrual of $18.4 million and records any difference between actual expenses incurred and this accrual as a regulatory asset or liability as appropriate.

For the year ended December 31, 2016, the Company incurred actual expenses in the amount of $19.5 million for major maintenance that is subject to this accrual. Cumulative costs for turbine maintenance in excess of cumulative collections are classified as a regulatory asset on the balance sheet.

Schedule Page: 402.5 Line No.: 11 Column: b
Unattended-automatic.

Schedule Page: 403.5 Line No.: 11 Column: d
SCE&G receives shaft horsepower from Kapstone Charleston Kraft LLC, a biomass/coal cogeneration facility, to operate SCE&G's generator.

Schedule Page: 402 Line No.: 43 Column: c2
All fuels.

Schedule Page: 402 Line No.: 43 Column: d1
All fuels.

Schedule Page: 402 Line No.: 43 Column: e1
All fuels.

Schedule Page: 402 Line No.: 44 Column: c2
All fuels.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) _ A Resubmission	/ /	2016/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: 44 Column: d1

All fuels.

Schedule Page: 402 Line No.: 44 Column: e1

All fuels.

Schedule Page: 402.1 Line No.: 43 Column: b1

All fuels.

Schedule Page: 402.1 Line No.: 44 Column: b1

All fuels.

Schedule Page: 402.3 Line No.: 43 Column: f1

All fuels.

Schedule Page: 402.5 Line No.: 43 Column: e1

All fuels.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1894 Plant Name: Parr (b)	FERC Licensed Project No. 516 Plant Name: Saluda (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1914	1930
4	Year Last Unit was Installed	1921	1971
5	Total installed cap (Gen name plate Rating in MW)	14.88	207.30
6	Net Peak Demand on Plant-Megawatts (60 minutes)	23	198
7	Plant Hours Connect to Load	8,704	8,433
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	12	200
10	(b) Under the Most Adverse Oper Conditions	7	200
11	Average Number of Employees	4	5
12	Net Generation, Exclusive of Plant Use - Kwh	44,387,000	130,763,000
13	Cost of Plant		
14	Land and Land Rights	602,632	6,157,073
15	Structures and Improvements	1,894,672	7,718,824
16	Reservoirs, Dams, and Waterways	4,818,228	354,675,505
17	Equipment Costs	5,250,629	13,964,814
18	Roads, Railroads, and Bridges	124,198	233,527
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	12,690,359	382,749,743
21	Cost per KW of Installed Capacity (line 20 / 5)	852.8467	1,846.3567
22	Production Expenses		
23	Operation Supervision and Engineering	76,387	298,226
24	Water for Power	0	0
25	Hydraulic Expenses	42,139	1,024,945
26	Electric Expenses	51,734	26,030
27	Misc Hydraulic Power Generation Expenses	449,073	139,091
28	Rents	0	0
29	Maintenance Supervision and Engineering	37	4,376
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	27,327	77,898
32	Maintenance of Electric Plant	558,687	413,535
33	Maintenance of Misc Hydraulic Plant	7,604	10,349
34	Total Production Expenses (total 23 thru 33)	1,212,988	1,994,450
35	Expenses per net KWh	0.0273	0.0153

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2535 Plant Name: Stevens Creek (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1914			3
1926			4
17.28	0.00	0.00	5
18	0	0	6
8,433	0	0	7
			8
10	0	0	9
8	0	0	10
3	0	0	11
57,309,000	0	0	12
			13
406,315	0	0	14
3,012,157	0	0	15
6,430,203	0	0	16
4,981,247	0	0	17
128,812	0	0	18
0	0	0	19
14,958,734	0	0	20
865.6675	0.0000	0.0000	21
			22
47,926	0	0	23
0	0	0	24
81,664	0	0	25
1,374	0	0	26
29,593	0	0	27
0	0	0	28
197	0	0	29
15,836	0	0	30
184,718	0	0	31
286,356	0	0	32
15,721	0	0	33
663,385	0	0	34
0.0116	0.0000	0.0000	35

Schedule Page: 406 Line No.: 1 Column: b

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: c

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: d

Operated under license from the Federal Energy Regulatory Commission.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 1984 Plant Name: Fairfield (b)
1	Type of Plant Construction (Conventional or Outdoor)	Outdoor
2	Year Originally Constructed	1978
3	Year Last Unit was Installed	1978
4	Total installed cap (Gen name plate Rating in MW)	587
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	528
6	Plant Hours Connect to Load While Generating	3,858
7	Net Plant Capability (in megawatts)	576
8	Average Number of Employees	25
9	Generation, Exclusive of Plant Use - Kwh	524,039,000
10	Energy Used for Pumping	721,050,000
11	Net Output for Load (line 9 - line 10) - Kwh	-197,011,000
12	Cost of Plant	
13	Land and Land Rights	22,147,163
14	Structures and Improvements	36,301,570
15	Reservoirs, Dams, and Waterways	74,706,638
16	Water Wheels, Turbines, and Generators	67,489,924
17	Accessory Electric Equipment	19,288,204
18	Miscellaneous Powerplant Equipment	6,484,247
19	Roads, Railroads, and Bridges	1,328,336
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	227,746,082
22	Cost per KW of installed cap (line 21 / 4)	387.9831
23	Production Expenses	
24	Operation Supervision and Engineering	227,020
25	Water for Power	
26	Pumped Storage Expenses	115,105
27	Electric Expenses	29,650
28	Misc Pumped Storage Power generation Expenses	379,853
29	Rents	
30	Maintenance Supervision and Engineering	147,356
31	Maintenance of Structures	2,526
32	Maintenance of Reservoirs, Dams, and Waterways	358,450
33	Maintenance of Electric Plant	1,543,535
34	Maintenance of Misc Pumped Storage Plant	75,776
35	Production Exp Before Pumping Exp (24 thru 34)	2,879,271
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	2,879,271
38	Expenses per KWh (line 37 / 9)	0.0055

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			36
			37
			38

Schedule Page: 408 Line No.: 38 Column: b

Required information per FERC Order No. 784, Docket No. AI14-1-000

Expenses per KWH of Generation and Pumping (Line37/(Line 9 + Line 10) = .0023

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro-Neal Shoals					
2	Hydro License					
3	Project #2315	1905	4.41	6.0	17,703,000	8,824,020
4						
5						
6						
7						
8						
9						
10						
11						
12						
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46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
498	239,713		357,630			3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						42
						43
						44
						45
						46

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	115 KV System	Various	115.00	230.00	Various	104.16	15.57	
2	115 KV System	Various	115.00	115.00	Various	1,404.87	100.80	
3	46 KV System	Various	46.00	115.00	Various	42.77		
4	46 KV System	Various	46.00	46.00	Various	578.19	25.77	
5	33 KV System	Various	33.00	33.00	Various	63.62	3.29	
6	13.8 KV System	SPA	13.80	46.00	Various	0.34		1
7	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP	11.10		1
8	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP		2.90	2
9	230 KV System							
10	CEC Cola Energy	Fold-in	230.00	230.00	Steel-SP	5.88		1
11	Canadys	Faber Place	230.00	230.00	Wood-H	36.43		1
12	Canadys	Faber Place #2	230.00	230.00	Wood-H	42.80		1
13	Canadys	Graniteville-SRP	230.00	230.00	Wood-H	0.08		1
14	Canadys	Sumter	230.00	230.00	Wood-H	32.00		1
15	Canadys	Urquhart	230.00	230.00	Wood-H	79.47		1
16	Canadys	Williams	230.00	230.00	Steel - SP	2.04		1
17	Canadys	Yemassee	230.00	230.00	Wood-H	30.30		1
18	Church Creek	Faber Place #2	230.00	230.00	Wood-H	3.97		1
19	Church Creek	Yemassee	230.00	230.00	Various	52.10		1
20	Cope	Orangeburg	230.00	230.00	Steel-SP	22.05		2
21	Cope	Canadys	230.00	230.00	Steel-SP	40.53		2
22	Edenwood	Denny Terrace	230.00	230.00	Wood-H	12.16		1
23	Edenwood	McMeekin	230.00	230.00	Various	11.48		1
24	Edenwood	Tie	230.00	230.00	Wood-H	1.45		1
25	Edenwood	Owens Steel	230.00	230.00	Steel-SP	0.41		1
26	Fairfield	Summer	230.00	230.00	Wood-H	2.79		1
27	Goose Creek	Ashley Phos.	230.00	230.00	Wood-H	3.10		1
28	Graniteville Sub #1	Graniteville Sub #2	230.00	230.00	Steel	0.06		1
29	Graniteville	Urquhart	230.00	230.00	Wood-H	11.23		1
30	Hanahan	Bushy Park	230.00	230.00	Wood-H	10.50		1
31	Hopkins	Tap	230.00	230.00	Steel-SP	2.84		1
32	Huron	Tap	230.00	230.00	Wood-H	0.11		1
33	Jasper	Yemassee#1	230.00	230.00	Steel-SP	39.49		2
34	Jasper	Yemassee#2	230.00	230.00	Steel-SP	39.27		2
35	Jasper	Purrysburg(Santee)	230.00	230.00	Steel-SP	1.24		2
36					TOTAL	3,251.73	190.20	91

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
Various	1,307,722	15,474,127	16,781,849					1
Various	35,477,511	353,174,505	388,652,016					2
Various	443,409	3,088,008	3,531,417					3
Various	2,386,526	42,556,250	44,942,776					4
Various	62,375	3,951,491	4,013,866					5
336mcm		31,047	31,047					6
336mcm								7
336mcm	4,930	638,577	643,507					8
	14,317,368	193,398,432	207,715,800					9
1272mcm								10
795mcm								11
795mcm								12
795mcm								13
795mcm								14
1272mcm								15
1272mcm								16
Various								17
1272mcm								18
1272mcm								19
795mcm								20
795mcm								21
1272mcm								22
Various								23
1272mcm								24
1272mcm								25
1272mcm								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
1272mcm								32
1272mcm								33
1272mcm								34
1272mcm								35
	72,918,094	690,163,933	763,082,027	51,577	5,149,324		5,200,901	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Ladson	Ashley Phos.	230.00	230.00	Wood-H	4.60		1
2	Lake Murray	Saluda River #1	230.00	230.00	Steel-SP	6.38		2
3	Lyles	Saluda River #1	230.00	230.00	Steel-SP	4.13		2
4	Lyles	Saluda River #2	230.00	230.00	Steel-SP	0.59		2
5	McMeekin	Parr	230.00	230.00	Wood-H	16.66		1
6	Parr	Denny Terrace	230.00	230.00	Wood-H	21.96		1
7	Parr	Duke	230.00	230.00	Tower		10.90	1
8	Pepperhill	Mateeba	230.00	230.00	Wood-H	7.10		1
9	Pineland	Denny Terrace	230.00	230.00	Steel-SP	8.46		2
10	St. George	Ladson	230.00	230.00	Wood-H	33.00		1
11	St. George	Williams	230.00	230.00	Steel-SP	0.97		1
12	Summer	Denny Terrace	230.00	230.00	Wood-H	4.53		1
13	Summer	Parr #1	230.00	230.00	Wood-H	2.38		1
14	Summer	Parr #2	230.00	230.00	Wood-H	2.26		1
15	Summer	Graniteville	230.00	230.00	Wood-H	63.26		1
16	Summer	Pineland	230.00	230.00	Wood-H	26.83		1
17	Summer	Denny Terrace	230.00	230.00	Wood-H	26.26		1
18	Summerville	Tap	230.00	230.00	Wood-H		0.08	1
19	Timberlake	Tap	230.00	230.00	Wood-SP	8.41		1
20	Urquhart	Fold-in	230.00	230.00	Steel-H	9.55		1
21	VCS1	Killian	230.00	230.00	Steel-SP	3.36		1
22	VCS1	Killian	230.00	230.00	Steel-SP	38.66		2
23	VCS2	Lake Murray #1	230.00	230.00	Steel-SP		20.53	2
24	Vogtle	SRP	230.00	230.00	Steel-H	17.10		1
25	Ward	Tie	230.00	230.00	Wood-H	0.07		1
26	Wateree	Denny Terrace	230.00	230.00	Wood-H	29.94		1
27	Wateree	Edenwood	230.00	230.00	Wood-H	27.80		1
28	Wateree	Sumter	230.00	230.00	Wood-H	0.86		1
29	Wateree	St. George	230.00	230.00	Wood-H	45.60		1
30	Wateree	Pineland	230.00	230.00	Wood-H	38.62		1
31	Wateree	Hercules	230.00	230.00	Wood-H	0.45		1
32	Wateree	Orangeburg	230.00	230.00	Wood-H	27.10		1
33	Wateree-Edenwd	Columbia	230.00	230.00	Steel-H		2.95	2
34	Williams	Wateree	230.00	230.00	Wood-H	10.30		1
35	Williams	Canadys	230.00	230.00	Wood-H	9.60	0.70	1
36					TOTAL	3,251.73	190.20	91

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795mcm								1
1272mcm								2
1272mcm								3
1272mcm								4
795mcm								5
795mcm								6
954mcm								7
Various								8
1272mcm								9
795mcm								10
1272mcm								11
1272mcm								12
1272mcm								13
1272mcm								14
1272mcm								15
1272mcm								16
1272mcm								17
1272mcm								18
1272mcm								19
1272mcm								20
1272mcm								21
1272mcm								22
1272mcm								23
795mcm								24
1272mcm								25
Various								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
795mcm								32
1272mcm								33
1272mcm								34
1272mcm								35
	72,918,094	690,163,933	763,082,027	51,577	5,149,324		5,200,901	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Williams	Faber Place #1	230.00	230.00	Steel-SP	0.53		2
2	Williams	Faber Place #2	230.00	230.00	Tower-H	13.65	6.71	2
3	Williams	Tie	230.00	230.00	Concrete	0.08		1
4	Williams	DuPont	230.00	230.00	Wood-H	6.60		1
5	Yemassee	Burton	230.00	230.00	Steel-SP	21.31		2
6	Yemassee	Santee	230.00	230.00	Wood-H	2.93		2
7	Underground							
8	33 KV System					0.23		2
9	46 KV System					0.90		1
10	115 KV System					19.88		1
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,251.73	190.20	91

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272mcm								1
1272mcm								2
1272mcm								3
1272mcm								4
1272mcm								5
1272mcm								6
								7
250mcm		16,443	16,443					8
750mcm		1,620,606	1,620,606					9
2250kcm	18,918,253	76,214,447	95,132,700					10
				51,577	5,149,324		5,200,901	11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	72,918,094	690,163,933	763,082,027	51,577	5,149,324		5,200,901	36

Schedule Page: 422 Line No.: 1 Column: h

Various

Schedule Page: 422 Line No.: 2 Column: h

Various

Schedule Page: 422 Line No.: 3 Column: h

Various

Schedule Page: 422 Line No.: 4 Column: h

Various

Schedule Page: 422 Line No.: 5 Column: h

Various

Schedule Page: 422 Line No.: 9 Column: l

Total capitalized cost of 230kV System.

Schedule Page: 422.2 Line No.: 11 Column: a

Reported costs in column (l) reflect total costs including balances recorded in Account 106 - Completed Construction not Classified. Columns (a) through (i) include statistical data related to unitized plant only.

Schedule Page: 422.2 Line No.: 11 Column: m

Operation expense includes Accounts 563 - Overhead Line Expenses and 564 - Underground Line Expenses.

Schedule Page: 422.2 Line No.: 11 Column: n

Maintenance expense includes Accounts 571 - Maintenance of Overhead Lines and 572 - Maintenance of Underground Lines.

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OVERHEAD						
2	Faber Place	James Island	0.98	Steel	14.00	1	1
3	Saluda Hydro	Williams St.	7.93	Steel	11.00	2	2
4	Summerville	Boonehill	0.64	Steel	11.00	2	2
5	Canadys	Williams	1.02	Steel	4.00	1	1
6	Church Creek	Yemassee	-17.00	Various	16.00	1	1
7	Orchids Paper Tap		1.03	Steel	19.00	1	1
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		-5.40		75.00	8	8

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
1272	ACSR		115		846,581			846,581	2
1272	ACSR		115		6,799,845	2,664,250		9,464,095	3
1272	ACSR		115		146,233	52,704		198,937	4
1272	ACSR		230		1,634,461	275,344		1,909,805	5
795	ACSR		115		-277,266	-536,343		-813,609	6
1272	ACSR		46	49,463	433,572	349,336		832,371	7
									8
									9
									10
									11
									12
									13
									14
									15
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									41
									42
									43
				49,463	9,583,426	2,805,291		12,438,180	44

Schedule Page: 424 Line No.: 6 Column: a

Negative numbers in columns (c), (m), (n) and (p) represent retirements in Sections 35 and 50. Since the line was altered, this activity is being reported in accordance with Instruction No. 1 of this schedule.

Schedule Page: 424 Line No.: 7 Column: k

Design Voltage 115

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Transmission Substations:				
2	Aiken, Aiken County	Trans-U	115.00	46.00	
3	Aiken, Aiken County	Trans-U	115.00	12.00	
4	Barnwell, Barnwell County	Trans-U	115.00	46.00	
5	Batesburg, City of Batesburg	Trans-U	115.00	33.00	
6	Bayview, Mt. Pleasant City	Trans-U	115.00	23.00	
7	Blackville 115-46KV, Barnwell County	Trans-U	115.00	46.00	
8	Burton Transmission, Beautfort County	Trans-U	230.00	115.00	
9	Burton Transmission, Beautfort County	Trans-U	115.00	46.00	
10	Calhoun County, Calhoun County	Trans-U	115.00	46.00	
11	Calhoun Falls, Calhoun Falls City	Trans-U	115.00	46.00	
12	Calhoun Falls, Calhoun Falls City	Trans-U	46.00	12.00	
13	Canadys Sub, Colleton County	Trans-U	230.00	115.00	
14	Charleston, Charleston County	Trans-U	115.00	23.00	
15	Church Creek, Charleston County	Trans-U	230.00	115.00	
16	Coit Gas Turbine, Richland County	Trans-U	13.80	33.00	
17	Coit, Richland County	Trans-U	115.00	23.00	
18	Coit, Richland County	Trans-U	115.00	33.00	
19	Columbia Industrial Park, Richland County	Trans-U	230.00	115.00	
20	Cope, Orangeburg County	Trans-U	230.00	115.00	
21	Cope, Orangeburg County	Trans-U	115.00	230.00	
22	Denmark, City of Denmark	Trans-U	115.00	46.20	
23	Denny Terrace, Richland County	Trans-U	230.00	115.00	
24	Edenwood, City of Cayce	Trans-U	230.00	115.00	
25	Faber Place, City of North Charleston	Trans-U	115.00	23.00	
26	Faber Place, City of North Charleston	Trans-U	230.00	115.00	
27	Fairfax, Allendale County	Trans-U	115.00	46.20	
28	Fairfield Pumped Storage, Fairfield County	Trans-U	13.80	230.00	
29	Goose Creek, Hanahan City	Trans-U	230.00	115.00	
30	Graniteville #1, Aiken County	Trans-U	115.00	46.00	
31	Graniteville #1, Aiken County	Trans-U	230.00	115.00	
32	Graniteville #2, Aiken County	Trans-U	230.00	115.00	
33	Hagood Gas Turbine, Charleston County	Trans-U	13.80	115.00	
34	Hagood Gas Turbine, Charleston County	Trans-U	13.20	115.00	
35	Hagood Gas Turbine, Charleston County	Trans-U	13.80	4.16	
36	Hamlin, Charleston County	Trans-U	115.00	25.00	
37	Hampton, Hampton County	Trans-U	115.00	46.00	
38	Hanahan, Hanahan City	Trans-U	115.00	25.00	
39	Hanahan, Hanahan City	Trans-U	115.00	46.00	
40	Hardeeville Gas Turbine, Jasper County	Trans-U	13.20	46.00	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
28	1					2
22	1					3
56	2					4
28	1					5
75	2	1				6
28	1					7
224	1					8
112	2	4				9
28	1					10
50	2	2				11
7	1					12
224	1	1				13
67	2					14
672	2					15
56	2					16
22	1					17
56	1					18
336	1					19
224	1					20
549	1					21
56	2					22
672	2					23
448	2					24
73	3					25
672	2	1				26
56	2					27
717	4	1				28
336	1					29
56	2					30
448	2					31
336	1					32
60	1					33
147	1					34
6	1					35
140	4					36
84	3	2				37
78	3					38
56	2					39
14	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hardeeville, Jasper County	Trans-U	115.00	46.00	
2	Hobcaw, Charleston County	Trans-U	115.00	24.94	
3	Hopkins, Richland County	Trans-U	230.00	115.00	
4	Jasper Gas Turbine, Jasper County	Trans-U	18.00	230.00	
5	Jasper Gas Turbine, Jasper County	Trans-U	21.00	230.00	
6	Kendrick, Richland County	Trans-U	115.00	23.00	
7	Kendrick, Richland County	Trans-U	115.00	33.00	
8	Killian, Richland County	Trans-U	230.00	115.00	
9	Lake Murray, Lexington County	Trans-U	230.00	115.00	
10	Lyles, Richland County	Trans-U	230.00	115.00	
11	Lyles, Richland County	Trans-U	115.00	23.00	
12	Lyles, Richland County	Trans-U	115.00	35.00	
13	Lyles, Richland County	Trans-U	33.00	4.80	
14	McCormick, McCormick County	Trans-U	115.00	46.00	
15	McMeekin, Lexington County	Trans-U	13.80	115.00	
16	Orangeburg #1, Orangeburg County	Trans-U	115.00	46.00	
17	Orangeburg East 230KV, Orangeburg County	Trans-U	230.00	115.00	
18	Parr Gas Turbine, Fairfield County	Trans-U	13.20	115.00	
19	Parr Hydro, Fairfield County	Trans-U	2.30	13.80	
20	Parr Steam, Fairfield County	Trans-U	115.00	13.20	
21	Pepperhill, Charleston County	Trans-U	230.00	115.00	
22	Pineland, Richland County	Trans-U	230.00	115.00	
23	Rader, Richland County	Trans-U	115.00	23.00	
24	Ridgeville, City of Ridgeville	Trans-U	115.00	46.00	
25	Ritter, Colleton County	Trans-U	230.00	115.00	
26	Saluda Hydro, Lexington County	Trans-U	13.20	115.00	
27	Saluda Hydro, Lexington County	Trans-U	115.00	23.00	
28	Saluda Hydro, Lexington County	Trans-U	115.00	13.20	
29	Saluda River, Lexington County	Trans-U	230.00	115.00	
30	Santee, Orangeburg County	Trans-U	230.00	46.20	
31	Santee, Orangeburg County	Trans-U	115.00	46.00	
32	Santee, Orangeburg County	Trans-U	230.00	115.00	
33	Savannah River, Federal Property	Trans-U	230.00	115.00	
34	St. Andrews, Charleston City	Trans-U	115.00	23.00	
35	St. George, Dorchester County	Trans-U	115.00	46.00	
36	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	2.30	46.00	
37	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	46.00	2.30	
38	Stevens Creek Sub, Columbia Cnty Ga.	Trans-U	115.00	46.20	
39	Summerville, Berkeley County	Trans-U	230.00	115.00	
40	Thomas Island, Charleston County	Trans-U	115.00	23.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
28	1					2
336	1					3
700	3					4
500	1					5
56	2	1				6
56	1					7
336	1					8
672	2	1				9
336	1	1				10
56	2					11
56	1					12
8	3					13
58	2	1				14
350	2					15
81	3					16
672	2					17
98	2	1				18
25	3					19
34	1					20
336	1					21
672	2	1				22
45	2					23
28	1					24
336	1					25
133	3					26
65	2					27
133	2					28
336	1					29
28	1					30
28	1					31
140	1					32
672	2					33
22	1					34
28	1					35
14	2					36
14	2					37
28	1	1				38
672	2					39
75	2					40

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Trenton, Edgefield County	Trans-U	115.00	23.00	
2	Trenton, Edgefield County	Trans-U	115.00	33.00	
3	Trenton, Edgefield County	Trans-U	115.00	46.00	
4	Urquhart 115KV, Aiken County	Trans-U	115.00	13.20	
5	Urquhart 115-46KV, Aiken County	Trans-U	115.00	46.00	
6	Urquhart 230KV, Aiken County	Trans-U	18.00	230.00	
7	Urquhart Gas Turbine, Aiken County	Trans-U	13.20	115.00	
8	V. C. Summer Substation, Fairfield County	Trans-U	22.00	242.00	
9	Ward, Saluda County	Trans-U	230.00	115.00	
10	Ward, Saluda County	Trans-U	115.00	23.00	
11	Ward, Saluda County	Trans-U	115.00	33.00	
12	Wateree Plant, Richland County	Trans-U	21.00	230.00	
13	Wateree Plant, Richland County	Trans-U	230.00	13.80	
14	Williams Gas Turbine, Berkeley County	Trans-U	13.20	115.00	
15	Williams St., Columbia City	Trans-U	115.00	33.00	
16	Williams St., Columbia City	Trans-U	115.00	23.00	
17	Williams Station, Berkeley County	Trans-U	20.00	242.00	
18	Williams Station, Berkeley County	Trans-U	115.00	230.00	
19	Williams Station, Berkeley County	Trans-U	230.00	4.16	
20	Williams Station, Berkeley County	Trans-U	230.00	23.00	
21	Williston Industrial Park , Barnwell County	Trans-U	115.00	46.00	
22	Yemassee, City of Yemassee	Trans-U	230.00	115.00	
23					
24	Distribution Substations:				
25	Adams Run, Charleston County	Dist-U	115.00	23.00	
26	Adams Run, Charleston County	Dist-U	115.00	46.00	
27	Aiken #2, Aiken County	Dist-U	115.00	12.00	
28	Aiken #3, Aiken County	Dist-U	115.00	12.00	
29	Aiken Hampton Avenue, Aiken City	Dist-U	115.00	12.00	
30	Aiken Industrial Park, Aiken City	Dist-U	46.00	23.00	
31	Aiken-Steifeltown, Aiken County	Dist-U	115.00	12.00	
32	Allendale, Allendale City	Dist-U	115.00	12.00	
33	Arrowwood Road, Richland County	Dist-U	115.00	23.00	
34	Ashley Phosphate, City of North Charleston	Dist-U	115.00	23.00	
35	Bacon's Bridge, Summerville City	Dist-U	115.00	23.00	
36	Baldock, Allendale County	Dist-U	115.00	12.00	
37	Bamberg Central, Bamberg City	Dist-U	43.80	12.00	
38	Barnwell City, Barnwell City	Dist-U	46.00	12.00	
39	Barnwell Heights, Barnwell City	Dist-U	46.00	12.00	
40	Barnwell Industrial Park, Barnwell County	Dist-U	43.80	12.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1	1				1
23	3					2
56	2					3
325	6	2				4
48	2					5
467	1	1				6
176	3	1				7
1232	1	1				8
364	2	1				9
22	1					10
28	1					11
1008	2	1				12
75	2					13
70	1					14
106	4	1				15
60	2					16
785	1	1				17
560	2					18
93	2					19
101	2					20
32	6					21
784	3					22
						23
						24
50	2					25
112	2					26
50	2					27
50	2					28
28	1					29
11	1					30
22	1					31
22	1					32
22	1					33
82	3					34
37	1					35
22	1					36
14	2					37
11	1					38
11	1					39
11	1					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Batesburg City, Lexington County	Dist-U	33.00	8.00	
2	Bayfront, Charleston City	Dist-U	115.00	23.00	
3	Beaufort Central, Beaufort City	Dist-U	115.00	12.00	
4	Beaufort Industrial Park, Beaufort County	Dist-U	115.00	12.00	
5	Bee Street, Charleston County	Dist-U	115.00	14.40	
6	Beech Island, Aiken County	Dist-U	46.00	12.00	
7	Bellwright, Berkeley County	Dist-U	115.00	23.00	
8	Belmont, Richland County	Dist-U	115.00	23.00	
9	Belvedere, North Augusta City	Dist-U	115.00	12.00	
10	Blackville 46-12KV, Barnwell County	Dist-U	46.00	12.00	
11	Bluffton, Beaufort County	Dist-U	115.00	23.00	
12	Blythewood, Richland County	Dist-U	115.00	23.00	
13	Boney Rd. , Fairfield County	Dist-U	115.00	23.00	
14	Boney Rd. , Fairfield County	Dist-U	115.00	23.00	
15	Boone Hill, Dorchester County	Dist-U	115.00	23.00	
16	Bowman, Orangeburg County	Dist-U	115.00	8.00	
17	Brookwood, West Columbia City	Dist-U	115.00	23.00	
18	Burton Central, Beaufort County	Dist-U	115.00	12.00	
19	CAE Industrial Park, Lexington County	Dist-U	115.00	23.00	
20	Cainhoy, Berkeley County	Dist-U	115.00	23.00	
21	Calhoun Street, Columbia City	Dist-U	115.00	8.00	
22	Callawassie Island, Jasper County	Dist-U	115.00	23.00	
23	Carlisle, Carlisle City	Dist-U	115.00	23.00	
24	Center Sub, Aiken County	Dist-U	46.00	23.00	23.00
25	Charleston Airport, N Charleston City	Dist-U	115.00	23.00	
26	Charlotte Street, Charleston City	Dist-U	115.00	14.40	
27	Church Creek, Charleston City	Dist-U	115.00	23.00	
28	Circle Drive, Richland County	Dist-U	115.00	8.00	
29	Clearwater, Aiken County	Dist-U	115.00	12.00	
30	Cloverleaf, Aiken County	Dist-U	115.00	12.00	
31	Colonial Heights, Richland County	Dist-U	115.00	23.00	
32	Columbia Airport, Springdale City	Dist-U	115.00	23.00	
33	Columbia Industrial Park, Richland County	Dist-U	115.00	23.00	
34	Congaree Creek, Cayce City	Dist-U	115.00	23.00	
35	Congaree Vista, Richland County	Dist-U	115.00	23.00	
36	Coosaw, Charleston County	Dist-U	115.00	23.00	
37	Cromer Rd, Lexington County	Dist-U	115.00	23.00	
38	Deer Park, Charleston County	Dist-U	115.00	23.00	
39	Denmark Industrial Park, Denmark City	Dist-U	46.00	12.00	
40	Dentsville, Richland County	Dist-U	115.00	23.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
40	1					2
28	1					3
22	1					4
202	4					5
11	1					6
28	1					7
50	2					8
50	2					9
11	1					10
56	2					11
77	2					12
23	1					13
22	1					14
60	2					15
11	1					16
28	1					17
56	2					18
28	1					19
56	2					20
22	1					21
28	1	1				22
13	4	1				23
11	1					24
40	1					25
101	4					26
75	2					27
22	1					28
28	1					29
22	1					30
22	1					31
22	1					32
40	1					33
28	1					34
37	1					35
37	1					36
37	1					37
45	2					38
11	1	1				39
45	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Dixiana, Lexington County	Dist-U	115.00	23.00	
2	East Columbia, Richland County	Dist-U	115.00	23.00	
3	Edmund, Lexington County	Dist-U	115.00	23.00	
4	Estill Southside, Estill City	Dist-U	46.00	12.00	
5	Estill, Estill City	Dist-U	46.00	13.80	
6	Eutawville, Orangeburg County	Dist-U	115.00	23.00	
7	Fairfax Central, Fairfax City	Dist-U	46.00	12.00	
8	Five Points, Columbia City	Dist-U	115.00	8.00	
9	Fort Johnston Road, Charleston County	Dist-U	115.00	23.00	
10	Frogmore, Beaufort County	Dist-U	115.00	23.00	
11	Gardens Corner, Beaufort County	Dist-U	115.00	23.00	
12	Gaston, Lexington County	Dist-U	115.00	23.00	
13	Gilbert, Lexington County	Dist-U	115.00	23.00	
14	Gills Creek, Richland County	Dist-U	115.00	23.00	
15	Grays Hill, Beaufort County	Dist-U	115.00	12.00	
16	Greengate, Richland County	Dist-U	115.00	23.00	
17	Grove Street, Charleston City	Dist-U	115.00	14.40	
18	Hampton City, Hampton County	Dist-U	46.00	12.00	
19	Hanahan Switching, Berkeley County	Dist-U	46.00	4.16	
20	Harbison, Lexington County	Dist-U	115.00	23.00	
21	Hardeeville, Hardeeville City	Dist-U	115.00	23.00	
22	Herrin, Allendale County	Dist-U	46.00	12.00	
23	Holly Hill, Holly Hill City	Dist-U	115.00	23.00	
24	Houndslake, Aiken County	Dist-U	115.00	12.00	
25	Howard Street, Richland County	Dist-U	33.00	8.00	
26	Irmo Town, Irmo City	Dist-U	115.00	23.00	
27	Isle of Palms, Isle of Palms City	Dist-U	115.00	23.00	
28	Jackson 46-12kV, Aiken County	Dist-U	46.00	12.00	
29	Jackson Street, Columbia City	Dist-U	115.00	8.00	
30	James Island, Charleston County	Dist-U	115.00	23.00	
31	James Prioleau, Charleston County	Dist-U	115.00	23.00	
32	Jasper Construction, Jasper County	Dist-U	115.00	23.00	
33	Johnston 115-23KV, Edgefield County	Dist-U	115.00	23.00	
34	Kilbourne Park, Richland County	Dist-U	115.00	23.00	
35	Killian, Richland County	Dist-U	115.00	23.00	
36	Kingswood, Richland County	Dist-U	115.00	23.00	
37	Kronotex, Barnwell County	Dist-U	115.00	12.00	
38	Ladies Island, Beaufort County	Dist-U	115.00	23.00	
39	Lake Carolina, Richland County	Dist-U	115.00	23.00	
40	Lake Murray Training, Lexington County	Dist-U	115.00	23.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
65	2					1
28	1					2
22	1					3
14	1	1				4
14	1					5
50	2					6
18	2					7
22	1					8
50	2					9
28	1					10
22	1					11
50	2					12
22	1					13
37	1					14
22	1					15
37	1					16
22	1					17
21	2					18
14	2	1				19
50	2					20
28	1	1				21
11	1					22
50	4	1				23
28	1					24
11	1					25
56	2					26
50	2					27
11	1					28
22	1					29
45	2					30
28	1					31
11	1					32
22	1					33
60	2					34
37	1					35
50	2					36
28	1					37
50	2					38
65	2					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Langley, Aiken County	Dist-U	115.00	12.00	
2	Laurel Bay 115-12KV, Beaufort County	Dist-U	115.00	12.00	
3	Leesville 115-23KV, Lexington County	Dist-U	115.00	23.00	
4	Lexington 115-23kV, Lexington County	Dist-U	115.00	23.00	
5	Lexington East Side, Lexington County	Dist-U	115.00	23.00	
6	Lexington Industrial Park, Lexington County	Dist-U	115.00	23.00	
7	Lexington West Side, Lexington County	Dist-U	115.00	23.00	
8	Lower Richland, Richland County	Dist-U	115.00	23.00	
9	Maryville, Charleston County	Dist-U	115.00	23.00	
10	McCormick City 115-13KV, McCormick Cnty	Dist-U	115.00	12.00	
11	Meadowbrook, Beaufort County	Dist-U	115.00	23.00	
12	Meeting Street, Charleston County	Dist-U	115.00	14.40	
13	Middleburg Mall, Richland County	Dist-U	115.00	8.00	
14	Midway, Union County	Dist-U	115.00	13.80	
15	Midway, Union County	Dist-U	23.00	2.40	
16	Mt Pleasant, Charleston County	Dist-U	115.00	23.00	
17	Muller Avenue, Richland County	Dist-U	115.00	8.00	
18	Muller Avenue, Richland County	Dist-U	115.00	23.00	
19	Navy Yard 115-23kV, Federal Property, SC	Dist-U	115.00	23.00	
20	Navy Yard 115-23kV, Federal Property, SC	Dist-U	115.00	13.80	
21	Neeses, Orangeburg County	Dist-U	46.00	8.00	
22	Network, Richland County	Dist-U	115.00	13.80	
23	North 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
24	North Augusta, Aiken City	Dist-U	115.00	12.00	
25	North Bridge Terrace, Charleston County	Dist-U	115.00	23.00	
26	North Naval Weapons, Federal Property	Dist-U	115.00	13.80	
27	North Rhett, North Charleston City	Dist-U	115.00	23.00	
28	Northpointe Business Park, Charleston County	Dist-U	115.00	23.00	
29	Northwoods Mall, North Charleston City	Dist-U	230.00	23.00	
30	Okatie, Jasper County	Dist-U	115.00	23.00	
31	Old Fort, Dorchester County	Dist-U	115.00	23.00	
32	Osceola Park, Charleston County	Dist-U	115.00	23.00	
33	Palmetto Commerce Park, Charleston City	Dist-U	115.00	23.00	
34	Park Street, Columbia City	Dist-U	33.00	13.80	13.80
35	Parr 13.2-23KV, Fairfield County	Dist-U	23.00	13.80	
36	Parr Hill 115-23kV, Fairfield County	Dist-U	115.00	23.00	
37	Pine Hill 230-23kV, Dorchester County	Dist-U	230.00	23.00	
38	Pelion, Lexington County	Dist-U	115.00	23.00	
39	Pendleton Street, Columbia City	Dist-U	115.00	8.00	
40	Piney Woods Road, Richland County	Dist-U	115.00	23.00	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
28	1					2
28	1					3
65	2	1				4
37	1					5
60	2	1				6
75	2					7
60	2					8
37	1					9
11	1	1				10
22	1					11
22	1					12
22	1					13
20	1	1				14
1	3					15
77	2					16
22	1					17
28	1					18
28	1					19
22	1					20
11	1					21
67	3					22
11	1					23
28	1					24
45	2					25
11	1					26
28	1					27
37	1					28
75	2	1				29
28	1					30
60	2					31
75	2					32
65	2					33
44	2	1				34
22	1					35
22	1					36
37	1					37
22	1	1				38
45	2					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Platt Springs Rd., Lexington County	Dist-U	115.00	23.00	
2	Platt Springs Rd., Lexington County	Dist-U	115.00	23.00	
3	Pontiac, Richland County	Dist-U	230.00	23.00	
4	Port Park, Hanahan City	Dist-U	115.00	23.00	
5	Port Royal, Port Royal City	Dist-U	115.00	12.00	
6	Pritchardville, Beaufort County	Dist-U	115.00	23.00	
7	Quail Hollow, Lexington County	Dist-U	115.00	23.00	
8	Raborn Pointe, North Augusta City	Dist-U	115.00	12.00	
9	Rantowles, Charleston County	Dist-U	115.00	23.00	
10	Red House Rd, Charleston County	Dist-U	46.00	23.00	
11	Richland Mall, Forest Acres City	Dist-U	115.00	8.00	
12	Ridgeland, Jasper County	Dist-U	115.00	23.00	
13	Riverland Terrace, Charleston County	Dist-U	115.00	23.00	
14	Riverland Terrace, Charleston County	Dist-U	23.00	4.16	
15	Rosewood, Columbia City	Dist-U	33.00	8.00	
16	S. C. Research Association, Richland County	Dist-U	115.00	23.00	
17	Sage Mill Ind Park, Aiken County	Dist-U	115.00	12.00	
18	Saluda County, Saluda County	Dist-U	115.00	23.00	
19	Sandhill, Richland County	Dist-U	115.00	23.00	
20	Santee 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
21	Savage Road, Charleston County	Dist-U	115.00	23.00	
22	Saxe Gotha Industrial Park, Lexington County	Dist-U	115.00	23.00	
23	Seven Mile, North Charleston City	Dist-U	115.00	23.00	
24	Shell Point, Beaufort County	Dist-U	46.00	12.00	
25	Silver Bluff Rd, Aiken County	Dist-U	115.00	12.00	
26	S-Lubeca, Richland County	Dist-U	115.00	12.00	
27	South Main, Columbia City	Dist-U	115.00	8.00	
28	Sparkleberry, Richland County	Dist-U	115.00	23.00	23.00
29	Sparkleberry, Richland County	Dist-U	115.00	23.00	
30	Springdale, Lexington County	Dist-U	115.00	23.00	
31	St. George 115-12kV, Dorchester County	Dist-U	115.00	12.00	
32	St. Helena Island, Beaufort County	Dist-U	115.00	23.00	
33	St. Matthews 46-23kV, Calhoun County	Dist-U	46.00	23.00	23.00
34	Stono Park, Charleston City	Dist-U	115.00	23.00	
35	Summer Construction, Fairfield County	Dist-U	115.00	23.00	
36	Summerville Central, Berkeley County	Dist-U	115.00	23.00	
37	Summerville Industrial Park, Dorchester County	Dist-U	115.00	23.00	
38	Summerville Plaza, City of Summerville	Dist-U	115.00	23.00	
39	Summerville-Ladson, Charleston County	Dist-U	115.00	23.00	
40	Swansea, Lexington County	Dist-U	46.00	23.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
22	1					2
75	2					3
22	1					4
28	1					5
37	1					6
37	1	2				7
22	1					8
28	1					9
45	2	1				10
45	2					11
22	1	1				12
22	1					13
4	1					14
21	2					15
22	1					16
28	1					17
22	1					18
75	2					19
21	2					20
45	2					21
37	1					22
22	1					23
25	2	1				24
22	1					25
22	1					26
22	1					27
37	1					28
37	1					29
45	2	1				30
28	1					31
50	2					32
23	2	1				33
37	1					34
22	1					35
40	1					36
50	2					37
37	1					38
60	2					39
11	1	1				40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Sweetwater, Aiken County	Dist-U	115.00	12.00	
2	Ten Mile, Charleston County	Dist-U	115.00	23.00	
3	Terminal, Richland County	Dist-U	33.00	8.00	
4	Timberlake, Lexington County	Dist-U	230.00	23.00	
5	Uptown, Columbia City	Dist-U	115.00	23.00	
6	Uptown, Columbia City	Dist-U	115.00	8.00	
7	Varnville, Varnville City	Dist-U	46.00	12.00	
8	Victory Gardens, Columbia City	Dist-U	115.00	8.00	
9	Wagener, Wagnener City	Dist-U	46.00	8.00	
10	Walterboro 115-23KV, Walterboro City	Dist-U	115.00	23.00	
11	Walterboro Forest Hill, Walterboro City	Dist-U	115.00	23.00	
12	Walterboro Ind Park, Walterboro City	Dist-U	115.00	23.00	
13	Walterboro Southside, Walterboro City	Dist-U	115.00	23.00	
14	West Columbia, West Columbia City	Dist-U	33.00	8.00	
15	White Gables, Dorchester County	Dist-U	115.00	23.00	
16	White Rock, Richland County	Dist-U	115.00	23.00	
17	Whitehall, Lexington County	Dist-U	115.00	23.00	
18	Williston, Williston City	Dist-U	115.00	12.00	
19	Winnsboro, Winnsboro City	Dist-U	115.00	23.00	
20	Woodfield Park, Richland County	Dist-U	115.00	23.00	
21	Yemassee Central, Yemassee City	Dist-U	115.00	23.00	
22					
23	Distribution Substations				
24	Under 10,000 KVA (36)	Dist-U			
25					
26	FUNCTIONAL SUMMARY OF CAPACITY				
27	Transmission Substations				
28	Distribution Substations				
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
28	1	1				1
22	1					2
11	1					3
37	1	1				4
37	1	1				5
23	1					6
11	1					7
22	1					8
11	1					9
22	1					10
40	1					11
28	1					12
22	1					13
18	2					14
37	1					15
50	2	1				16
22	1					17
22	1					18
45	2					19
45	2					20
22	1					21
						22
6719						23
203						24
						25
						26
22047						27
6922						28
						29
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Schedule Page: 426.7 Line No.: 24 Column: c

Various

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Natural Gas Commodity and Demand	SEMI	803/547	111,453,041
3	Refined Coal Purchases	Canadys Refined Coal, LLC	419	64,468,085
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18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Rental Fee for Use of Assets	SCANA Services	454/493	5,165,616
22	Coal Sales	Canadys Refined Coal, LLC	419	64,062,406
23				
24				
25				
26				
27				
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42				

Schedule Page: 429 Line No.: 2 Column: b

See page 102 for abbreviations used for Affiliated Companies.

Schedule Page: 429 Line No.: 3 Column: b

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and selling of refined coal to reduce emissions.

Schedule Page: 429 Line No.: 8 Column: a

The transactions below represent activities billed by SCANA Services, Inc. to SCE&G during the billing period.

REPORTING BUSINESS UNIT	Category	FERC Account	Direct Billed	Allocated	Total Billed
SCEG	Corporate Security	1070	145,919	42,234	188,154
SCEG	Corporate Security	1080	13,854	0	13,854
SCEG	Corporate Security	1180	10,619	4,643	15,262
SCEG	Corporate Security	1630	1,368	0	1,368
SCEG	Corporate Security	1823	246,121	0	246,121
SCEG	Corporate Security	1860	0	3,295	3,295
SCEG	Corporate Security	4081	173,255	27,811	201,065
SCEG	Corporate Security	4210	0	3,509	3,509
SCEG	Corporate Security	4261	0	2,998	2,998
SCEG	Corporate Security	4265	81,297	11,803	93,101
SCEG	Corporate Security	9040	(1,602)	0	(1,602)
SCEG	Corporate Security	9050	391	0	391
SCEG	Corporate Security	9200	2,454,399	394,100	2,848,499
SCEG	Corporate Security	9210	747,627	54,749	802,376
SCEG	Corporate Security	9230	3,610,265	558,266	4,168,531
SCEG	Corporate Security	9250	(95)	0	(95)
SCEG	Corporate Security	9260	622,579	264,155	886,734
SCEG	Corporate Security	9310	36,992	202	37,194
SCEG	Corporate Security	9350	9,392	2,332	11,724
SCEG	Customer Services & Operational Support	1070	1,348,726	222,752	1,571,478
SCEG	Customer Services & Operational Support	1180	789,711	24,487	814,198
SCEG	Customer Services & Operational Support	1823	107,002	0	107,002
SCEG	Customer Services & Operational Support	1840	342,049	0	342,049
SCEG	Customer Services & Operational Support	1860	11,238	17,378	28,616
SCEG	Customer Services & Operational Support	4081	927,346	87,217	1,014,563
SCEG	Customer Services & Operational Support	4082	507	1,436	1,943
SCEG	Customer Services & Operational Support	4160	64,924	13,766	78,690
SCEG	Customer Services & Operational Support	4171	5,388	5,236	10,624
SCEG	Customer Services & Operational Support	4210	0	18,506	18,506
SCEG	Customer Services & Operational Support	4261	1,398	3,781	5,179
SCEG	Customer Services & Operational Support	4265	38,972	9,197	48,169
SCEG	Customer Services & Operational Support	5370	96	0	96
SCEG	Customer Services & Operational Support	5617	2,455	0	2,455
SCEG	Customer Services & Operational Support	5800	96,831	0	96,831
SCEG	Customer Services & Operational Support	5880	450,822	0	450,822

SCEG	Customer Services & Operational Support	5930	194,451	0	194,451
SCEG	Customer Services & Operational Support	8700	964	0	964
SCEG	Customer Services & Operational Support	8740	228,911	1,651	230,561
SCEG	Customer Services & Operational Support	8850	406	0	406
SCEG	Customer Services & Operational Support	9010	1,192,528	1,630	1,194,158
SCEG	Customer Services & Operational Support	9020	38,203	0	38,203
SCEG	Customer Services & Operational Support	9030	14,883,547	1,223,424	16,106,971
SCEG	Customer Services & Operational Support	9050	2,358,307	94,374	2,452,681
SCEG	Customer Services & Operational Support	9080	61,538	497	62,035
SCEG	Customer Services & Operational Support	9200	1,000,296	99,826	1,100,122
SCEG	Customer Services & Operational Support	9210	438,796	21,018	459,813
SCEG	Customer Services & Operational Support	9230	2,111	9,460	11,572
SCEG	Customer Services & Operational Support	9260	3,292,525	1,169,610	4,462,135
SCEG	Customer Services & Operational Support	9301	27,500	0	27,500
SCEG	Customer Services & Operational Support	9302	1,805	0	1,805
SCEG	Customer Services & Operational Support	9310	1,714	40,242	41,956
SCEG	Customer Services & Operational Support	9350	80,517	2,068	82,585
SCEG	Employee Services	1070	3,194,775	930,808	4,125,583
SCEG	Employee Services	1080	6,574	0	6,574
SCEG	Employee Services	1180	3,708,987	163,075	3,872,062
SCEG	Employee Services	1190	210	0	210
SCEG	Employee Services	1540	11,540	0	11,540
SCEG	Employee Services	1823	13,641	0	13,641
SCEG	Employee Services	1840	136,276	575,812	712,088
SCEG	Employee Services	1860	(88,740)	7,583	(81,157)
SCEG	Employee Services	4081	1,552,158	281,617	1,833,775
SCEG	Employee Services	4082	1,079	2,659	3,738
SCEG	Employee Services	4160	10,365	1,941	12,307
SCEG	Employee Services	4171	4,319	9,156	13,476
SCEG	Employee Services	4210	0	8,075	8,075
SCEG	Employee Services	4261	0	662	662
SCEG	Employee Services	4265	32,749	989,058	1,021,807
SCEG	Employee Services	5000	10,359	0	10,359
SCEG	Employee Services	5010	190	0	190
SCEG	Employee Services	5020	25	0	25
SCEG	Employee Services	5060	2,641	0	2,641
SCEG	Employee Services	5120	458	0	458
SCEG	Employee Services	5140	50	0	50
SCEG	Employee Services	5170	233	0	233
SCEG	Employee Services	5200	80	0	80
SCEG	Employee Services	5240	161,914	0	161,914
SCEG	Employee Services	5370	4,754	0	4,754
SCEG	Employee Services	5390	174	0	174
SCEG	Employee Services	5490	194	0	194
SCEG	Employee Services	5560	55	0	55

SCEG	Employee Services	5620	650	0	650
SCEG	Employee Services	5660	722	0	722
SCEG	Employee Services	5692	96	0	96
SCEG	Employee Services	5700	90	0	90
SCEG	Employee Services	5710	405	0	405
SCEG	Employee Services	5800	75	0	75
SCEG	Employee Services	5830	2,024	0	2,024
SCEG	Employee Services	5850	95	0	95
SCEG	Employee Services	5880	48,603	0	48,603
SCEG	Employee Services	5920	145	0	145
SCEG	Employee Services	5930	8,439	0	8,439
SCEG	Employee Services	5970	35	0	35
SCEG	Employee Services	8410	94	0	94
SCEG	Employee Services	8439	25	0	25
SCEG	Employee Services	8700	70,454	572	71,026
SCEG	Employee Services	8740	72,165	43,751	115,916
SCEG	Employee Services	8790	35	0	35
SCEG	Employee Services	8800	7,355	60	7,415
SCEG	Employee Services	8870	137,734	0	137,734
SCEG	Employee Services	9010	25	0	25
SCEG	Employee Services	9020	40	0	40
SCEG	Employee Services	9030	318,836	31,040	349,876
SCEG	Employee Services	9050	60,586	0	60,586
SCEG	Employee Services	9070	94	0	94
SCEG	Employee Services	9080	8,767	0	8,767
SCEG	Employee Services	9100	33,311	63,771	97,081
SCEG	Employee Services	9120	4,588	0	4,588
SCEG	Employee Services	9200	25,683,087	2,920,601	28,603,687
SCEG	Employee Services	9210	1,249,960	710,817	1,960,778
SCEG	Employee Services	9230	6,311	548,413	554,724
SCEG	Employee Services	9250	189,680	172,998	362,678
SCEG	Employee Services	9260	930,673	1,195,276	2,125,949
SCEG	Employee Services	9302	581	65,233	65,814
SCEG	Employee Services	9310	13,721	1,244,044	1,257,765
SCEG	Employee Services	9350	7,595	2,407	10,002
SCEG	Environmental Services	1070	133,007	35,940	168,947
SCEG	Environmental Services	1080	279,582	0	279,582
SCEG	Environmental Services	1180	59,300	3,951	63,251
SCEG	Environmental Services	1210	3,080	0	3,080
SCEG	Environmental Services	1823	(425)	0	(425)
SCEG	Environmental Services	1840	91,056	0	91,056
SCEG	Environmental Services	1860	52,838	2,804	55,642
SCEG	Environmental Services	4081	128,290	24,405	152,695
SCEG	Environmental Services	4082	1,682	0	1,682
SCEG	Environmental Services	4171	6,382	0	6,382

SCEG	Environmental Services	4210	0	2,986	2,986
SCEG	Environmental Services	4261	10,430	3,844	14,274
SCEG	Environmental Services	4265	26,120	18,220	44,339
SCEG	Environmental Services	5060	3,333	0	3,333
SCEG	Environmental Services	5240	1,667	0	1,667
SCEG	Environmental Services	5390	3,333	0	3,333
SCEG	Environmental Services	5490	556	0	556
SCEG	Environmental Services	5660	27,223	0	27,223
SCEG	Environmental Services	5880	16,112	0	16,112
SCEG	Environmental Services	5920	5,931	0	5,931
SCEG	Environmental Services	7350	1,109,646	0	1,109,646
SCEG	Environmental Services	9200	1,390,321	341,457	1,731,778
SCEG	Environmental Services	9210	415,347	45,693	461,040
SCEG	Environmental Services	9230	1,087,014	105,470	1,192,484
SCEG	Environmental Services	9260	477,456	225,413	702,869
SCEG	Environmental Services	9302	56,416	0	56,416
SCEG	Environmental Services	9310	1,649	0	1,649
SCEG	Environmental Services	9350	311,806	0	311,806
SCEG	Executive Services	1070	1,691,362	53,870	1,745,233
SCEG	Executive Services	1180	0	5,922	5,922
SCEG	Executive Services	1210	10,172	0	10,172
SCEG	Executive Services	1840	212,102	0	212,102
SCEG	Executive Services	1860	4,378	4,203	8,580
SCEG	Executive Services	4081	77,974	139,946	217,921
SCEG	Executive Services	4082	2,141	21,981	24,122
SCEG	Executive Services	4171	7,779	82,528	90,307
SCEG	Executive Services	4210	0	4,476	4,476
SCEG	Executive Services	4261	0	36,775	36,775
SCEG	Executive Services	4264	113,870	116	113,986
SCEG	Executive Services	4265	206,168	670,696	876,864
SCEG	Executive Services	5170	72,045	0	72,045
SCEG	Executive Services	5240	6,592	0	6,592
SCEG	Executive Services	5660	70,483	0	70,483
SCEG	Executive Services	5880	34,778	0	34,778
SCEG	Executive Services	5930	964,845	0	964,845
SCEG	Executive Services	9200	2,923,730	1,980,714	4,904,444
SCEG	Executive Services	9210	538,518	51,168	589,686
SCEG	Executive Services	9230	0	15,383	15,383
SCEG	Executive Services	9260	269,094	556,375	825,469
SCEG	Executive Services	9302	840,971	0	840,971
SCEG	Executive Services	9310	0	4,041	4,041
SCEG	Executive Services	9350	196,764	0	196,764
SCEG	Financial Services	1070	9,605,691	301,075	9,906,766
SCEG	Financial Services	1180	9,537,361	43,803	9,581,163
SCEG	Financial Services	1823	2,317,871	0	2,317,871

SCEG	Financial Services	1832	229	0	229
SCEG	Financial Services	1840	71,427	114,165	185,592
SCEG	Financial Services	1860	153,564	9,676	163,240
SCEG	Financial Services	4081	227,130	4,752,445	4,979,574
SCEG	Financial Services	4082	107,939	7,329	115,268
SCEG	Financial Services	4101	0	0	0
SCEG	Financial Services	4140	1,026,167	11,133,207	12,159,374
SCEG	Financial Services	4160	8,752	47,507	56,259
SCEG	Financial Services	4171	5,298	4,902	10,200
SCEG	Financial Services	4210	0	10,304	10,304
SCEG	Financial Services	4261	(400)	0	(400)
SCEG	Financial Services	4264	64	2,019	2,082
SCEG	Financial Services	4265	102,764	316,794	419,558
SCEG	Financial Services	4300	0	6,296,983	6,296,983
SCEG	Financial Services	4310	9,539	0	9,539
SCEG	Financial Services	4320	0	(6,802)	(6,802)
SCEG	Financial Services	5240	(68,093)	0	(68,093)
SCEG	Financial Services	5370	218	0	218
SCEG	Financial Services	5560	87,167	0	87,167
SCEG	Financial Services	5617	(1,750)	0	(1,750)
SCEG	Financial Services	5880	404	0	404
SCEG	Financial Services	5920	(1,736)	0	(1,736)
SCEG	Financial Services	7350	(639,068)	0	(639,068)
SCEG	Financial Services	8740	3,994	0	3,994
SCEG	Financial Services	9010	0	15	15
SCEG	Financial Services	9030	391,773	54,372	446,144
SCEG	Financial Services	9050	460	0	460
SCEG	Financial Services	9080	252	0	252
SCEG	Financial Services	9200	2,799,912	3,125,984	5,925,896
SCEG	Financial Services	9210	65,749	(125,327)	(59,579)
SCEG	Financial Services	9230	1,868,764	2,283,656	4,152,420
SCEG	Financial Services	9240	(405,940)	382,714	(23,226)
SCEG	Financial Services	9250	1,902,721	(7,303)	1,895,418
SCEG	Financial Services	9260	975,020	1,501,115	2,476,135
SCEG	Financial Services	9280	175	0	175
SCEG	Financial Services	9302	0	252,212	252,212
SCEG	Financial Services	9310	6,056	9,230	15,286
SCEG	Financial Services	9350	519,807	154,463	674,270
SCEG	Gas Control Coordination & Gas Engineering Services	1070	0	22,708	22,708
SCEG	Gas Control Coordination & Gas Engineering Services	1180	779,799	2,496	782,295
SCEG	Gas Control Coordination & Gas Engineering Services	1823	2,884,761	0	2,884,761
SCEG	Gas Control Coordination & Gas Engineering Services	1860	8,791	1,772	10,563
SCEG	Gas Control Coordination & Gas Engineering Services	4081	42,800	46,730	89,530
SCEG	Gas Control Coordination & Gas Engineering Services	4210	0	1,887	1,887
SCEG	Gas Control Coordination & Gas Engineering Services	4265	499	447	946

SCEG	Gas Control Coordination & Gas Engineering Services	8400	68,461	2,585	71,046
SCEG	Gas Control Coordination & Gas Engineering Services	8410	40,660	1,531	42,191
SCEG	Gas Control Coordination & Gas Engineering Services	8432	3,990	0	3,990
SCEG	Gas Control Coordination & Gas Engineering Services	8510	0	235	235
SCEG	Gas Control Coordination & Gas Engineering Services	8610	0	6,534	6,534
SCEG	Gas Control Coordination & Gas Engineering Services	8700	329,314	244,351	573,665
SCEG	Gas Control Coordination & Gas Engineering Services	8740	106,280	369,675	475,955
SCEG	Gas Control Coordination & Gas Engineering Services	8800	27,307	1,075	28,382
SCEG	Gas Control Coordination & Gas Engineering Services	8850	467	734	1,200
SCEG	Gas Control Coordination & Gas Engineering Services	8870	394,360	0	394,360
SCEG	Gas Control Coordination & Gas Engineering Services	9010	351	0	351
SCEG	Gas Control Coordination & Gas Engineering Services	9050	3,251	0	3,251
SCEG	Gas Control Coordination & Gas Engineering Services	9100	272,213	1,931	274,143
SCEG	Gas Control Coordination & Gas Engineering Services	9120	107	1,399	1,506
SCEG	Gas Control Coordination & Gas Engineering Services	9200	259,333	89,717	349,050
SCEG	Gas Control Coordination & Gas Engineering Services	9210	7,059	30,258	37,317
SCEG	Gas Control Coordination & Gas Engineering Services	9230	0	(1,275)	(1,275)
SCEG	Gas Control Coordination & Gas Engineering Services	9260	169,185	265,452	434,636
SCEG	Gas Control Coordination & Gas Engineering Services	9302	145,030	0	145,030
SCEG	Gas Measurement Services	1070	690	6,470	7,160
SCEG	Gas Measurement Services	1180	589,763	711	590,474
SCEG	Gas Measurement Services	1630	88,651	0	88,651
SCEG	Gas Measurement Services	1860	0	505	505
SCEG	Gas Measurement Services	4081	9,176	4,688	13,865
SCEG	Gas Measurement Services	4210	0	538	538
SCEG	Gas Measurement Services	8700	33,346	7,450	40,795
SCEG	Gas Measurement Services	8740	90	617	707
SCEG	Gas Measurement Services	8750	0	393	393
SCEG	Gas Measurement Services	8760	0	552	552
SCEG	Gas Measurement Services	8780	0	410	410
SCEG	Gas Measurement Services	8800	10,908	2,426	13,334
SCEG	Gas Measurement Services	8900	330	0	330
SCEG	Gas Measurement Services	8930	98,256	52,703	150,959
SCEG	Gas Measurement Services	9200	878	60,368	61,246
SCEG	Gas Measurement Services	9210	(9,460)	7,121	(2,339)
SCEG	Gas Measurement Services	9230	0	673	673
SCEG	Gas Measurement Services	9260	33,182	42,182	75,364
SCEG	Gas Measurement Services	9310	0	277,576	277,576
SCEG	Gas Supply and Fuel Procurement	1070	164	10,916	11,080
SCEG	Gas Supply and Fuel Procurement	1180	0	1,200	1,200
SCEG	Gas Supply and Fuel Procurement	1823	113	0	113
SCEG	Gas Supply and Fuel Procurement	1860	0	852	852
SCEG	Gas Supply and Fuel Procurement	4081	26,149	26,851	53,001
SCEG	Gas Supply and Fuel Procurement	4210	0	907	907
SCEG	Gas Supply and Fuel Procurement	4265	136	8,121	8,257

SCEG	Gas Supply and Fuel Procurement	5240	6,737	0	6,737
SCEG	Gas Supply and Fuel Procurement	8700	1	0	1
SCEG	Gas Supply and Fuel Procurement	9200	372,579	376,240	748,820
SCEG	Gas Supply and Fuel Procurement	9210	5,693	112,714	118,407
SCEG	Gas Supply and Fuel Procurement	9260	98,638	141,020	239,658
SCEG	Information Services	1070	12,924,324	934,333	13,858,657
SCEG	Information Services	1080	11,305	0	11,305
SCEG	Information Services	1180	756,932	130,767	887,700
SCEG	Information Services	1190	1,242	0	1,242
SCEG	Information Services	1210	886,599	0	886,599
SCEG	Information Services	1630	178,215	0	178,215
SCEG	Information Services	1822	3,530	0	3,530
SCEG	Information Services	1823	3,276,379	0	3,276,379
SCEG	Information Services	1840	872,806	479,712	1,352,518
SCEG	Information Services	1860	416,245	3,279	419,525
SCEG	Information Services	2270	(580,862)	0	(580,862)
SCEG	Information Services	2430	(305,737)	0	(305,737)
SCEG	Information Services	4081	92,299	19,747	112,046
SCEG	Information Services	4082	8,671	0	8,671
SCEG	Information Services	4140	8,305	120,061	128,366
SCEG	Information Services	4160	36,418	111,211	147,628
SCEG	Information Services	4171	295,944	0	295,944
SCEG	Information Services	4210	0	3,492	3,492
SCEG	Information Services	4261	0	9,693	9,693
SCEG	Information Services	4264	0	2,652	2,652
SCEG	Information Services	4265	218,854	172,147	391,001
SCEG	Information Services	5000	7,836	0	7,836
SCEG	Information Services	5010	10,451	0	10,451
SCEG	Information Services	5060	549,559	0	549,559
SCEG	Information Services	5170	10,885	0	10,885
SCEG	Information Services	5190	53,772	0	53,772
SCEG	Information Services	5200	337,946	0	337,946
SCEG	Information Services	5240	4,892,229	0	4,892,229
SCEG	Information Services	5280	687	0	687
SCEG	Information Services	5290	31,771	0	31,771
SCEG	Information Services	5300	2,228	0	2,228
SCEG	Information Services	5320	1,439,668	0	1,439,668
SCEG	Information Services	5350	4,556	0	4,556
SCEG	Information Services	5370	9,167	0	9,167
SCEG	Information Services	5380	909	0	909
SCEG	Information Services	5390	129,363	0	129,363
SCEG	Information Services	5440	471	0	471
SCEG	Information Services	5460	6,179	0	6,179
SCEG	Information Services	5480	357	0	357
SCEG	Information Services	5490	105,506	0	105,506

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2016/Q4

FOOTNOTE DATA

SCEG	Information Services	5560	162,280	0	162,280
SCEG	Information Services	5600	11,583	0	11,583
SCEG	Information Services	5611	6,749	0	6,749
SCEG	Information Services	5612	43,000	0	43,000
SCEG	Information Services	5620	188,506	0	188,506
SCEG	Information Services	5630	852	0	852
SCEG	Information Services	5660	199,350	0	199,350
SCEG	Information Services	5680	23,686	0	23,686
SCEG	Information Services	5700	206,583	0	206,583
SCEG	Information Services	5710	3,943	0	3,943
SCEG	Information Services	5730	175,429	0	175,429
SCEG	Information Services	5800	74,034	0	74,034
SCEG	Information Services	5810	1,383	0	1,383
SCEG	Information Services	5820	142,770	0	142,770
SCEG	Information Services	5830	8,132	0	8,132
SCEG	Information Services	5860	12,391	0	12,391
SCEG	Information Services	5880	913,845	0	913,845
SCEG	Information Services	5900	376	0	376
SCEG	Information Services	5920	48,248	0	48,248
SCEG	Information Services	5930	88,020	0	88,020
SCEG	Information Services	5940	49,152	0	49,152
SCEG	Information Services	5950	323	0	323
SCEG	Information Services	5960	9,067	0	9,067
SCEG	Information Services	5970	65,655	0	65,655
SCEG	Information Services	5980	1,505	0	1,505
SCEG	Information Services	8400	838	0	838
SCEG	Information Services	8410	12,155	0	12,155
SCEG	Information Services	8439	9,769	0	9,769
SCEG	Information Services	8700	18,297	0	18,297
SCEG	Information Services	8710	7,762	0	7,762
SCEG	Information Services	8740	86,709	0	86,709
SCEG	Information Services	8750	38,743	0	38,743
SCEG	Information Services	8760	102,897	0	102,897
SCEG	Information Services	8780	15,923	0	15,923
SCEG	Information Services	8790	14,909	0	14,909
SCEG	Information Services	8800	325,807	0	325,807
SCEG	Information Services	8870	2,861	0	2,861
SCEG	Information Services	8900	301	0	301
SCEG	Information Services	8920	2,954	0	2,954
SCEG	Information Services	8930	21,983	0	21,983
SCEG	Information Services	8940	736	0	736
SCEG	Information Services	9010	28,031	0	28,031
SCEG	Information Services	9020	550,599	166,731	717,331
SCEG	Information Services	9030	16,329,927	240,160	16,570,087
SCEG	Information Services	9050	624,893	0	624,893

SCEG	Information Services	9070	1,750	0	1,750
SCEG	Information Services	9080	153,283	0	153,283
SCEG	Information Services	9100	4,717	0	4,717
SCEG	Information Services	9110	2,646	0	2,646
SCEG	Information Services	9120	265,470	0	265,470
SCEG	Information Services	9160	44	335,669	335,713
SCEG	Information Services	9200	552,554	285,081	837,635
SCEG	Information Services	9210	9,096,489	5,367,853	14,464,342
SCEG	Information Services	9230	77,848	76,506	154,354
SCEG	Information Services	9260	326,943	232,182	559,125
SCEG	Information Services	9302	142,236	4,756	146,992
SCEG	Information Services	9310	486,351	39,393	525,745
SCEG	Information Services	9350	2,210,255	30,868	2,241,123
SCEG	Land & Facilities Management	1070	2,935,340	50,688	2,986,028
SCEG	Land & Facilities Management	1080	2,374,315	0	2,374,315
SCEG	Land & Facilities Management	1180	4,344,402	7,738	4,352,140
SCEG	Land & Facilities Management	1190	171,505	0	171,505
SCEG	Land & Facilities Management	1210	261,746	0	261,746
SCEG	Land & Facilities Management	1630	44,974	0	44,974
SCEG	Land & Facilities Management	1823	(2,350)	0	(2,350)
SCEG	Land & Facilities Management	1830	488	0	488
SCEG	Land & Facilities Management	1840	158,092	20,534	178,627
SCEG	Land & Facilities Management	1860	130,590	1,635	132,225
SCEG	Land & Facilities Management	4081	51,798	36,889	88,687
SCEG	Land & Facilities Management	4082	12,516	4,907	17,423
SCEG	Land & Facilities Management	4160	0	150,266	150,266
SCEG	Land & Facilities Management	4171	37,575	18,237	55,812
SCEG	Land & Facilities Management	4210	0	1,741	1,741
SCEG	Land & Facilities Management	4261	0	56,116	56,116
SCEG	Land & Facilities Management	4265	361,595	92,732	454,327
SCEG	Land & Facilities Management	5010	721,602	0	721,602
SCEG	Land & Facilities Management	5060	68,938	0	68,938
SCEG	Land & Facilities Management	5110	213,072	0	213,072
SCEG	Land & Facilities Management	5120	124,117	0	124,117
SCEG	Land & Facilities Management	5130	715	0	715
SCEG	Land & Facilities Management	5140	22,329	0	22,329
SCEG	Land & Facilities Management	5170	25,349	0	25,349
SCEG	Land & Facilities Management	5190	4,475	0	4,475
SCEG	Land & Facilities Management	5240	46,734	0	46,734
SCEG	Land & Facilities Management	5290	469,455	0	469,455
SCEG	Land & Facilities Management	5300	22,826	0	22,826
SCEG	Land & Facilities Management	5310	0	0	0
SCEG	Land & Facilities Management	5320	38,535	0	38,535
SCEG	Land & Facilities Management	5370	8,829	0	8,829
SCEG	Land & Facilities Management	5390	36,977	0	36,977

SCEG	Land & Facilities Management	5430	43,228	0	43,228
SCEG	Land & Facilities Management	5440	50,080	0	50,080
SCEG	Land & Facilities Management	5450	3,282	0	3,282
SCEG	Land & Facilities Management	5460	6,648	0	6,648
SCEG	Land & Facilities Management	5490	64,112	0	64,112
SCEG	Land & Facilities Management	5510	2,889	0	2,889
SCEG	Land & Facilities Management	5520	1,921	0	1,921
SCEG	Land & Facilities Management	5530	19,347	0	19,347
SCEG	Land & Facilities Management	5560	40,143	0	40,143
SCEG	Land & Facilities Management	5620	38	0	38
SCEG	Land & Facilities Management	5630	544	0	544
SCEG	Land & Facilities Management	5660	45,552	0	45,552
SCEG	Land & Facilities Management	5690	27,498	0	27,498
SCEG	Land & Facilities Management	5700	26,078	0	26,078
SCEG	Land & Facilities Management	5710	90,362	0	90,362
SCEG	Land & Facilities Management	5730	2,332	0	2,332
SCEG	Land & Facilities Management	5800	3,328	0	3,328
SCEG	Land & Facilities Management	5820	75	0	75
SCEG	Land & Facilities Management	5830	558	0	558
SCEG	Land & Facilities Management	5860	2,006	0	2,006
SCEG	Land & Facilities Management	5880	52,475	0	52,475
SCEG	Land & Facilities Management	5890	237,849	0	237,849
SCEG	Land & Facilities Management	5900	1,267	0	1,267
SCEG	Land & Facilities Management	5910	2,548	0	2,548
SCEG	Land & Facilities Management	5920	110,117	0	110,117
SCEG	Land & Facilities Management	5930	34,335	0	34,335
SCEG	Land & Facilities Management	5940	2,418	0	2,418
SCEG	Land & Facilities Management	5970	1,037	0	1,037
SCEG	Land & Facilities Management	5980	4,881	0	4,881
SCEG	Land & Facilities Management	8410	138	0	138
SCEG	Land & Facilities Management	8432	15,009	0	15,009
SCEG	Land & Facilities Management	8439	13,379	0	13,379
SCEG	Land & Facilities Management	8750	4,420	0	4,420
SCEG	Land & Facilities Management	8790	481	0	481
SCEG	Land & Facilities Management	8810	225,904	0	225,904
SCEG	Land & Facilities Management	8870	2,010	0	2,010
SCEG	Land & Facilities Management	9020	6,648	0	6,648
SCEG	Land & Facilities Management	9030	10,187	0	10,187
SCEG	Land & Facilities Management	9050	42,009	0	42,009
SCEG	Land & Facilities Management	9080	3,623	0	3,623
SCEG	Land & Facilities Management	9120	4,066	0	4,066
SCEG	Land & Facilities Management	9200	2,887	0	2,887
SCEG	Land & Facilities Management	9210	77,261	25,730	102,991
SCEG	Land & Facilities Management	9260	120,794	207,331	328,125
SCEG	Land & Facilities Management	9302	622	0	622

SCEG	Land & Facilities Management	9310	3,477,705	562,406	4,040,111
SCEG	Land & Facilities Management	9320	716	0	716
SCEG	Land & Facilities Management	9350	2,763,795	2,101,625	4,865,420
SCEG	Legal	1070	3,207,431	54,504	3,261,934
SCEG	Legal	1180	411,733	5,992	417,725
SCEG	Legal	1210	7,937	0	7,937
SCEG	Legal	1823	134,808	0	134,808
SCEG	Legal	1830	21,529	0	21,529
SCEG	Legal	1832	337,265	0	337,265
SCEG	Legal	1860	1,528,533	4,252	1,532,785
SCEG	Legal	4081	109,669	116,537	226,207
SCEG	Legal	4082	113	14	127
SCEG	Legal	4160	6,471	0	6,471
SCEG	Legal	4171	419	49	468
SCEG	Legal	4210	0	4,528	4,528
SCEG	Legal	4265	24,959	170,887	195,846
SCEG	Legal	5240	(76)	0	(76)
SCEG	Legal	5617	1,075	0	1,075
SCEG	Legal	5660	1,130	0	1,130
SCEG	Legal	7350	(3,038)	0	(3,038)
SCEG	Legal	8920	(567)	0	(567)
SCEG	Legal	9030	19	0	19
SCEG	Legal	9040	1,000	0	1,000
SCEG	Legal	9080	6,688	0	6,688
SCEG	Legal	9200	1,275,748	1,624,807	2,900,555
SCEG	Legal	9210	(84,602)	243,080	158,478
SCEG	Legal	9230	2,994,858	1,408,542	4,403,399
SCEG	Legal	9250	1,919,661	226,685	2,146,346
SCEG	Legal	9260	405,639	637,413	1,043,052
SCEG	Legal	9280	(2,511)	0	(2,511)
SCEG	Legal	9302	0	1,892,139	1,892,139
SCEG	Legal	9350	547	13,412	13,959
SCEG	Marketing & Sales	1070	38,832	35,201	74,033
SCEG	Marketing & Sales	1180	0	3,870	3,870
SCEG	Marketing & Sales	1823	116,393	0	116,393
SCEG	Marketing & Sales	1860	0	2,746	2,746
SCEG	Marketing & Sales	4081	50,644	46,174	96,819
SCEG	Marketing & Sales	4082	67,685	1,685	69,371
SCEG	Marketing & Sales	4160	4,239,941	23,680	4,263,621
SCEG	Marketing & Sales	4171	246,591	6,209	252,800
SCEG	Marketing & Sales	4210	0	2,925	2,925
SCEG	Marketing & Sales	4265	1,958,153	22,148	1,980,301
SCEG	Marketing & Sales	5660	761	0	761
SCEG	Marketing & Sales	9070	35	0	35
SCEG	Marketing & Sales	9100	890	0	890

SCEG	Marketing & Sales	9110	5,017	0	5,017
SCEG	Marketing & Sales	9120	175,136	2,065	177,201
SCEG	Marketing & Sales	9130	642	5,975	6,616
SCEG	Marketing & Sales	9160	231,130	0	231,130
SCEG	Marketing & Sales	9200	332,705	661,774	994,478
SCEG	Marketing & Sales	9210	9,770	56,831	66,601
SCEG	Marketing & Sales	9230	16,365	16,107	32,472
SCEG	Marketing & Sales	9260	189,767	303,186	492,952
SCEG	Marketing & Sales	9280	0	617	617
SCEG	Marketing & Sales	9301	0	835	835
SCEG	Marketing & Sales	9302	50,433	44,375	94,808
SCEG	Marketing & Sales	9310	1,774	2,750	4,523
SCEG	Procurement	1070	649,652	36,522	686,174
SCEG	Procurement	1080	6,432	0	6,432
SCEG	Procurement	1180	291,473	4,015	295,488
SCEG	Procurement	1630	292,239	0	292,239
SCEG	Procurement	1860	0	2,849	2,849
SCEG	Procurement	4081	44,690	65,331	110,021
SCEG	Procurement	4082	0	215	215
SCEG	Procurement	4171	0	872	872
SCEG	Procurement	4210	0	3,034	3,034
SCEG	Procurement	4265	220	34,316	34,537
SCEG	Procurement	5240	100	0	100
SCEG	Procurement	5930	2,425	0	2,425
SCEG	Procurement	9120	0	3,021	3,021
SCEG	Procurement	9200	642,960	918,921	1,561,881
SCEG	Procurement	9210	10,175	122,534	132,709
SCEG	Procurement	9230	0	16,496	16,496
SCEG	Procurement	9260	168,126	379,827	547,953
SCEG	Procurement	9302	0	61,830	61,830
SCEG	Procurement	9310	8,524	0	8,524
SCEG	Public Affairs	1070	434,585	38,258	472,844
SCEG	Public Affairs	1180	0	4,206	4,206
SCEG	Public Affairs	1823	3,826	0	3,826
SCEG	Public Affairs	1860	0	2,985	2,985
SCEG	Public Affairs	4081	65,769	21,863	87,632
SCEG	Public Affairs	4082	53,109	35,792	88,900
SCEG	Public Affairs	4171	199,087	134,880	333,968
SCEG	Public Affairs	4210	0	3,179	3,179
SCEG	Public Affairs	4261	3,027,247	39,298	3,066,545
SCEG	Public Affairs	4264	813,075	587,312	1,400,387
SCEG	Public Affairs	4265	1,091,703	276,430	1,368,132
SCEG	Public Affairs	5930	15,042	0	15,042
SCEG	Public Affairs	9100	1,518	465	1,983
SCEG	Public Affairs	9200	910,346	301,248	1,211,595

SCEG	Public Affairs	9210	539,573	286,412	825,985
SCEG	Public Affairs	9260	241,839	226,520	468,359
SCEG	Public Affairs	9280	1,156	0	1,156
SCEG	Public Affairs	9302	0	5,054	5,054
SCEG	Public Affairs	9310	2,635	15,672	18,307
SCEG	Public Affairs	9350	0	54	54
SCEG	Regulatory	1070	436,379	20,248	456,627
SCEG	Regulatory	1180	0	2,226	2,226
SCEG	Regulatory	1823	14,439	0	14,439
SCEG	Regulatory	1860	0	1,580	1,580
SCEG	Regulatory	4081	83,881	10,639	94,520
SCEG	Regulatory	4082	0	392	392
SCEG	Regulatory	4171	0	1,472	1,472
SCEG	Regulatory	4210	0	1,682	1,682
SCEG	Regulatory	4265	3,818	13,062	16,880
SCEG	Regulatory	9200	923,692	152,476	1,076,169
SCEG	Regulatory	9210	30,805	20,141	50,946
SCEG	Regulatory	9230	1,166,088	62,496	1,228,584
SCEG	Regulatory	9260	315,763	116,451	432,214
SCEG	Regulatory	9280	338,133	0	338,133
SCEG	Regulatory	9310	6,654	0	6,654
SCEG	Regulatory	9350	0	449	449
SCEG	Strategic Planning	1070	216,218	30,822	247,040
SCEG	Strategic Planning	1180	530	3,388	3,918
SCEG	Strategic Planning	1840	2,022	0	2,022
SCEG	Strategic Planning	1860	0	2,405	2,405
SCEG	Strategic Planning	4081	104,829	33,267	138,096
SCEG	Strategic Planning	4082	16	568	584
SCEG	Strategic Planning	4171	87	2,017	2,104
SCEG	Strategic Planning	4210	0	2,561	2,561
SCEG	Strategic Planning	4265	1,021	21,300	22,321
SCEG	Strategic Planning	9200	1,492,277	472,725	1,965,003
SCEG	Strategic Planning	9210	292,896	98,957	391,853
SCEG	Strategic Planning	9260	393,869	238,494	632,363
SCEG	Strategic Planning	9280	16,356	0	16,356
SCEG	Strategic Planning	9302	1,424,160	0	1,424,160
SCEG	Strategic Planning	9310	7,511	0	7,511
	Grand Total		243,110,120	76,430,526	319,540,646

Incentive compensation costs are included in the Employee Services category.

The Financial Services category includes depreciation, property taxes, accrued payroll and other costs recorded at a corporate level by SCANA Services, Inc.

Allocated costs billed from SCANA Services, Inc. are billed using one of the approved methodologies described below.

1. Information Systems Charge-back Rates - Rates for services, including but not limited to Software, Consulting, Mainframe, Midtier and Network Connectivity Services, are based on the costs of labor, materials and Information Services overheads related to the provision of each service. Such rates are applied based on the specific equipment employed and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

2. Margin Revenue Ratio - "Margin" is equal to the excess of sales revenues over the applicable cost of sales, i.e., cost of fuel for generation and gas for resale. The numerator is equal to margin revenues for a specific Client Entity and the denominator is equal to the combined margin revenues of all the applicable Client Entities. This ratio is evaluated annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, based on results of operations for a subsequent twelve-month period, as may be required due to significant changes.

3. Number of Customers Ratio - A ratio based on the number of customers served by each subsidiary or operating unit. This ratio is determined annually based on actual number of customers and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

4. Number of Employees Ratio - A ratio based on the number of employees benefiting from the performance of a service. This ratio is determined annually based on actual counts of applicable employees and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

5. Three-Factor Formula - This formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

6. Modified Three-Factor Method - A ratio for the allocation of non-directly assigned corporate governance costs. The Modified Three-Factor Method provides for an allocation of costs to the principal holding company; the Three-Factor Method does not. The formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues. For the purpose of the Modified Three-Factor Method, the dividends resulting from operations of the subsidiaries are used as a proxy for revenues for the principal holding company.

7. Telecommunications Charge-back Rates - Rates for use of telecommunications services other than those encompassed by Information Systems Charge-back Rates are based on the costs of labor, materials, outside services and Telecommunications overheads. Such rates are applied based on the specific equipment employment and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

8. Gas Sales Ratio - A ratio based on the actual number of dekatherms of natural gas sold by the applicable gas distribution or marketing operations. This ratio is determined annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, as may be required due to significant changes.

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Amount based on measured usage of assets to include computer resource usage, margin revenues, three-factor formula, number of customers and number of employees.

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Schedule	Page No.

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
South Carolina Electric & Gas Company	**End of** 2015/Q4

Deloitte.

Deloitte & Touche LLP

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USA

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INDEPENDENT AUDITORS' REPORT

South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying financial statements of South Carolina Electric & Gas Company (the "Company"), which comprise the balance sheet — regulatory basis as of December 31, 2015, and the related statements of income — regulatory basis, retained earnings — regulatory basis, and cash flows — regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2015, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

As discussed before Note 1 to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Restricted Use

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

April 15, 2016

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
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Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent South Carolina Electric & Gas Company	02 Year/Period of Report End of 2015/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 100 SCANA Parkway, Cayce, SC 29033-3712	
05 Name of Contact Person Lisa Honeycutt	06 Title of Contact Person Accounting Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 Operation Way - MC B131, Cayce, SC 29033-3701	

08 Telephone of Contact Person *Including Area Code* (803) 217-7416	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts

01 Name Jimmy E Addison 02 Title Executive Vice President and CFO	03 Signature Jimmy E Addison	04 Date Signed *(Mo, Da, Yr)* 04/15/2016

Title 18, U S C 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

James E. Swan, IV, Vice President and Controller
100 SCANA Parkway
Cayce, SC 29033-3712

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

South Carolina - July 19, 1924

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

South Carolina - Electric, Gas

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

The respondent is a wholly-owned subsidiary of SCANA Corporation (SCANA). SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA holds directly all of the capital stock of the respondent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	South Carolina Fuel Company, Inc.	Acquires, owns, provides	None	
2		financing for and sells at		
3		cost to SCE&G nuclear fuel,		
4		certain fossil fuels and		
5		emission allowances.		
6				
7	South Carolina Generating Company, Inc.	Owns A.M. Williams	None	
8		Generating Station and sells		
9		electricity solely to SCE&G.		
10				
11	SRFI, LLC	A single member LLC	None	
12		holding investments in		
13		companies involved with		
14		re-engineered fuel.		
15				
16	APOG, LLC	Provides technical,	None	
17		engineering and procurement		
18		support services to and for		
19		the benefit of members and		
20		their licensing, development		
21		and construction of AP1000		
22		nuclear power plants.		
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27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Canadys Refined Coal, LLC	Manufactures and sells	None	
2		refined coal to reduce		
3		emissions.		
4				
5	Brandon Shores Coaltech, LLC	Manufactures and sells	None	
6		refined coal to reduce		
7		emissions.		
8				
9	Louisa Refined Coal, LLC	Manufactures and sells	None	
10		refined coal to reduce		
11		emissions.		
12				
13	Carolinas Virginia Nuclear Power	A non-profit corporation	None	
14	Associates, Inc. (CVNPA)	formed in 1956 by member		
15		companies to jointly study		
16		economic ways to produce and		
17		utilize nuclear material and		
18		atomic energy. Operated a		
19		nuclear power plant from		
20		1963 - 1967.		
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Schedule Page: 103 Line No.: 1 Column: d

Control held by SCE&G under the terms of a fuel contract. The accounts of SCFC are fully consolidated herein.

Schedule Page: 103 Line No.: 7 Column: d

SCE&G has determined that it has a controlling financial interest in South Carolina Generating Company, Inc. under the terms of a Power Purchase Agreement. Accordingly, SCE&G consolidates the accounts of South Carolina Generating Company, Inc. for financial reporting under Generally Accepted Accounting Principles. Since South Carolina Generating Company, Inc. is a separate FERC reporting entity and per guidance from FERC staff, South Carolina Generating Company, Inc. has not been consolidated in this Form 1 report.

Schedule Page: 103 Line No.: 11 Column: d

SRFI, LLC is a single member LLC in which SCE&G is the sole member and no stock was issued.

Schedule Page: 103 Line No.: 16 Column: d

SCE&G holds a 25% interest in APOG, LLC. Other members include Duke Energy, Southern Nuclear Operating Company and Florida Power & Light Company.

Schedule Page: 103.1 Line No.: 1 Column: d

SCE&G holds a 40% interest in Canadys Refined Coal, LLC. The other member is AJG Coal, Inc.

Schedule Page: 103.1 Line No.: 5 Column: d

SCE&G holds a 10% interest in Brandon Shores Coaltech, LLC. Other members include AJG Coal, Inc. and BSW Refined Coal.

Schedule Page: 103.1 Line No.: 9 Column: d

SCE&G holds a 10% interest in Louisa Refined Coal, LLC. Other members include AJG Coal, Inc. and LRC Holdings.

Schedule Page: 103.1 Line No.: 13 Column: d

SCE&G holds a 25% interest in CVNPA. Other members include Duke Power Company (Duke Energy Carolinas, LLC), Carolina Power & Light Company (Duke Energy Progress) and Virginia Electric and Power Company (Dominion Virginia Power).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	Chairman and Chief Executive Officer	Kevin B. Marsh	1,018,615
3	Chief Operating Officer and President of Generation		
4	and Transmission	Stephen A. Byrne	623,439
5	President of Retail Operations	W. Keller Kissam	383,739
6	President of Gas Operations	D. Russell Harris	213,869
7	Executive Vice President and		
8	Chief Financial Officer	Jimmy E. Addison	445,537
9	Senior Vice President of Fuel Procurement,		
10	Asset Management and		
11	Power Marketing (Through 12/15)		
12	Senior Vice President - Risk Management		
13	and Corporate Compliance (Effective 1/16)	Sarena D. Burch	249,746
14	Senior Vice President, General Counsel		
15	and Assistant Secretary	Ronald T. Lindsay	297,385
16	Senior Vice President Administration	Martin K. Phalen	218,588
17	Senior Vice President and Chief Nuclear Officer	Jeffrey B. Archie	383,761
18	Senior Vice President of Economic Development,		
19	Governmental & Regulatory Affairs	Kenneth R. Jackson	242,820
20	Vice President of Governmental Affairs	Henry E. Barton, Jr.	136,231
21	Vice President of Human Resources	Annmarie C. Higgins	194,330
22	Vice President of Marketing and Communications	Catherine B. Love	168,585
23	Vice President of Electric Operations	William J. Turner III	217,709
24	Vice President of Gas Operations	Felicia R. Howard	213,843
25	Vice President of Fossil Hydro	James M. Landreth	258,173
26	Vice President of Customer Relations and		
27	Renewables	Daniel F. Kassis	224,174
28	Vice President of Customer Service	Samuel L. Dozier	195,179
29	Vice President of SCANA Support Services	Stacy O. Shuler, Jr.	184,802
30	Vice President of Electric Transmission	Pandelis N. Xanthakos	178,550
31	Vice President of Nuclear Operations	Thomas D. Gatlin	308,002
32	Vice President of New Nuclear Operations	Ronald A. Jones	300,080
33	Vice President of Nuclear Financial Administration	Carlette L. Walker	263,283
34	Treasurer and Risk Management Officer		
35	(Vice President and Treasurer Effective 2/16)	Mark R. Cannon	203,789
36	Secretary (Vice President and Secretary		
37	Effective 2/16)	Gina S. Champion	163,881
38	Controller (Vice President and Controller		
39	Effective 2/16)	James E. Swan, IV	201,070
40	Chief Information Officer (VIce President and		
41	Chief Information Officer Effective 2/16)	Randal M. Senn	233,258
42			
43			
44			

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 104 Line No.: 1 Column: c

Amounts reported reflect the portion of the officer's salary that was assigned to the respondent during the reporting period.

Schedule Page: 104 Line No.: 34 Column: a

Effective January 2016, the role of Risk Management Officer was assigned to Sarena D. Burch.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	J. A. Bennett	Columbia, South Carolina
2	J.F.A.V. Cecil	Asheville, North Carolina
3	D. M. Hagood***	Charleston, South Carolina
4	J. M. Micali***	Boston, Massachusetts
5	L. M. Miller	Great Falls, Virginia
6	J.W. Roquemore***	Orangeburg, South Carolina
7	M. K. Sloan***	Durham, North Carolina
8	H. C. Stowe***	Pawleys Island, South Carolina
9	A. Trujillo	Atlanta, Georgia
10	K. B. Marsh, Chairman	
11	and Chief Executive Officer of	
12	SCANA Corporation and SCE&G**	Cayce, South Carolina
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Schedule Page: 105 Line No.: 14 Column: a

In January 2016, Gregory E. Aliff and Sharon A. Decker were appointed to the Company's Board of Directors.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Schedule 1, Schedule 7, Schedule 8, Attachment H	ER10-516
2		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes

[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20150515-5265	05/15/2015	ER10-516	Annual Update Informational Filing	Schedule 1, 7, 8, Attachment H
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. One twenty year municipal electric and gas franchise agreement was established during the first quarter of 2015 without payment of consideration.

Three twenty year municipal electric and gas franchise agreements were established during the second quarter of 2015 without payment of consideration.

One twenty year municipal electric and gas franchise agreement was established during the third quarter of 2015 without payment of consideration.

One twenty year municipal electric only and two electric and gas franchise agreements were established during the fourth quarter of 2015 without payment of consideration.

2. None

3. None

4. None

5. None

6. The Company's obligation under short-term borrowing arrangements on the respective Balance Sheet dates was as follows:

12/31/2015	12/31/2014
$420,225,000	$708,647,000

Such short-term borrowings have been authorized by FERC (Docket No. ES14-48-000).

In December 2015, SCE&G's existing five-year and three-year credit agreements were amended and extended by one year, such that they expire in December 2020 and December 2018, respectively.

In 2015, the Company borrowed $521,400,000 and paid back $538,187,861 from the SCANA Utility Money Pool. At 12/31/2015, SCE&G had no borrowings outstanding and $9,420,000 invested with the SCANA Utility Money Pool.

In May 2015, SCE&G issued $500 million of 5.10% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G’s construction program, to finance capital expenditures, and for general corporate purposes.

Such long-term borrowings have been authorized by the SCPSC (Docket No. 2013-132-E).

For additional information, see Notes 4, 6 and 7 to the Financial Statements.

7. None

8. None

9. See Notes 2 and 10 to the Financial Statements.

10. None

11. (Reserved)

12. Not Applicable

13. During the first quarter of 2016, the following changes in Company Officers and Directors became effective:

Sharon A. Decker and Gregory E. Aliff were appointed to the Company's Board of Directors.

Sarena D. Burch, formerly Senior Vice President- Fuel Procurement & Asset Management, was appointed Senior Vice President - Risk Management & Corporate Compliance.

Thomas D. Gatlin, formerly Vice President of Nuclear Operations, was appointed Vice President of Nuclear Support Services.

George A. Lippard,III was appointed Vice President of Nuclear Operations.

James E. Swan, IV, Controller, was named Vice President and Controller.

Randall M. Senn, Chief Information Officer, was named Vice President and Chief Information Officer.

Gina S. Champion, Secretary, was named Vice President and Secretary.

Mark R. Cannon, Treasurer and Risk Management Officer, was named Vice President and Treasurer.

14. Not Applicable

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	10,456,789,235	10,240,705,596
3	Construction Work in Progress (107)	200-201	3,990,834,928	3,295,945,264
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		14,447,624,163	13,536,650,860
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,149,318,951	4,061,048,465
6	Net Utility Plant (Enter Total of line 4 less 5)		10,298,305,212	9,475,602,395
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	81,161,353	132,721,361
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		116,928,535	116,157,676
9	Nuclear Fuel Assemblies in Reactor (120.3)		223,038,612	222,874,273
10	Spent Nuclear Fuel (120.4)		673,993,828	598,661,721
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	786,794,670	741,106,879
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		308,327,658	329,308,152
14	Net Utility Plant (Enter Total of lines 6 and 13)		10,606,632,870	9,804,910,547
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		68,776,649	68,466,914
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,108,780	1,060,728
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	1,394,608	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		61,516	2,177,912
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		114,983,724	122,653,840
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		4,539,044	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		188,646,761	192,237,938
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		127,896,448	97,217,327
36	Special Deposits (132-134)		12,236,393	99,118,583
37	Working Fund (135)		62,025	84,051
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		218,883,482	250,112,474
41	Other Accounts Receivable (143)		201,397,221	193,324,597
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,964,230	3,572,212
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		9,450,009	95,139,393
45	Fuel Stock (151)	227	57,600,683	68,741,416
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	128,029,866	121,215,971
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	656,143	675,532

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	351	8
55	Gas Stored Underground - Current (164.1)		15,144,464	20,698,970
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		8,250,772	9,606,007
57	Prepayments (165)		82,477,535	68,681,531
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		101,515,765	115,840,005
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		14,895,948	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		4,539,044	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		970,993,831	1,136,883,653
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		31,259,886	28,445,789
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	126,656,202	137,617,628
72	Other Regulatory Assets (182.3)	232	1,703,585,141	1,629,813,402
73	Prelim. Survey and Investigation Charges (Electric) (183)		198,470	115,044
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	84,634,918	86,416,963
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		16,258,765	17,687,903
82	Accumulated Deferred Income Taxes (190)	234	276,025,196	286,877,391
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,238,618,578	2,186,974,120
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		14,004,892,040	13,321,006,258

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	576,405,122	576,405,122
3	Preferred Stock Issued (204)	250-251	100,000	100,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	2,188,167,716	1,987,672,935
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	4,335,379	4,335,379
11	Retained Earnings (215, 215.1, 216)	118-119	2,265,470,454	2,077,189,755
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-2,770,003	-3,146,214
16	Total Proprietary Capital (lines 2 through 15)		5,023,037,910	4,633,886,219
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,428,770,000	3,928,770,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	100,185,967	100,203,972
22	Unamortized Premium on Long-Term Debt (225)		24,981,816	25,619,188
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		22,751,632	19,999,788
24	Total Long-Term Debt (lines 18 through 23)		4,531,186,151	4,034,593,372
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		12,477,819	10,772,461
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		5,355,089	3,338,743
29	Accumulated Provision for Pensions and Benefits (228.3)		186,867,019	196,649,207
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		21,708,781	17,248,442
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		476,223,696	521,027,126
35	Total Other Noncurrent Liabilities (lines 26 through 34)		702,632,404	749,035,979
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		420,225,000	708,647,000
38	Accounts Payable (232)		450,763,775	284,424,409
39	Notes Payable to Associated Companies (233)		0	16,787,861
40	Accounts Payable to Associated Companies (234)		77,601,960	94,663,510
41	Customer Deposits (235)		57,087,060	54,814,873
42	Taxes Accrued (236)	262-263	337,368,808	166,040,369
43	Interest Accrued (237)		64,981,070	62,813,355
44	Dividends Declared (238)		72,300,000	72,500,000
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		8,534,964	6,991,109
48	Miscellaneous Current and Accrued Liabilities (242)		71,869,175	73,352,764
49	Obligations Under Capital Leases-Current (243)		3,860,666	3,274,644
50	Derivative Instrument Liabilities (244)		54,566,151	224,303,955
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		21,708,781	17,248,442
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,597,449,848	1,751,365,407
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	23,580,500	25,951,600
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	69,255,823	75,473,817
60	Other Regulatory Liabilities (254)	278	147,235,196	119,704,334
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	12,361,300	10,509,025
63	Accum. Deferred Income Taxes-Other Property (282)		1,532,935,108	1,518,007,215
64	Accum. Deferred Income Taxes-Other (283)		365,217,800	402,479,290
65	Total Deferred Credits (lines 56 through 64)		2,150,585,727	2,152,125,281
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		14,004,892,040	13,321,006,258

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,929,818,797	3,091,428,231		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,397,711,033	1,655,465,370		
5	Maintenance Expenses (402)	320-323	150,487,404	145,271,659		
6	Depreciation Expense (403)	336-337	246,035,441	267,952,165		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	9,373,615	9,028,136		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	860,418	860,418		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		18,061,442	18,061,442		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,061,940	1,061,940		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	210,726,419	201,595,140		
15	Income Taxes - Federal (409.1)	262-263	213,774,190	37,221,716		
16	- Other (409.1)	262-263	31,833,545	-4,796,877		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	279,501,015	421,394,100		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	294,732,032	242,370,067		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,371,100	-3,567,600		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,262,323,330	2,507,177,542		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		667,495,467	584,250,689		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,557,104,822	2,629,218,129	372,713,975	462,210,102			2
						3
1,143,617,023	1,312,927,067	254,094,010	342,536,971		1,332	4
142,330,167	137,006,886	8,157,237	8,264,773			5
220,178,807	243,300,173	25,856,634	24,651,992			6
						7
8,443,725	7,992,210	929,890	1,035,926			8
854,201	854,201	6,217	6,217			9
18,061,442	18,061,442					10
						11
1,061,940	1,061,940					12
						13
185,840,612	178,478,738	24,885,807	23,116,416		-14	14
212,968,289	26,658,600	805,901	10,563,516		-400	15
31,801,445	-7,572,800	32,100	2,776,023		-100	16
253,565,716	396,817,100	25,935,299	24,577,000			17
281,879,832	223,430,032	12,852,200	18,940,035			18
-1,285,700	-2,288,400	-1,085,400	-1,279,200			19
						20
						21
						22
						23
						24
1,935,557,835	2,089,867,125	326,765,495	417,309,599		818	25
621,546,987	539,351,004	45,948,480	44,900,503		-818	26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		667,495,467	584,250,689		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		7,102,682	4,678,010		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		4,357,022	3,148,936		
33	Revenues From Nonutility Operations (417)			28,800		
34	(Less) Expenses of Nonutility Operations (417.1)		613,039	881,007		
35	Nonoperating Rental Income (418)		123,848	120,511		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,827,566			
37	Interest and Dividend Income (419)		3,795,907	-1,663,204		
38	Allowance for Other Funds Used During Construction (419.1)		24,828,339	27,737,866		
39	Miscellaneous Nonoperating Income (421)		16,450,885	70,992,261		
40	Gain on Disposition of Property (421.1)		4,048,536	273,925		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		46,552,570	98,138,226		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		33,834	33,834		
45	Donations (426.1)		8,408,608	8,333,437		
46	Life Insurance (426.2)		58,652	-281,910		
47	Penalties (426.3)		-49,866	43,000		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,622,234	1,520,473		
49	Other Deductions (426.5)		9,538,330	13,044,079		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		20,611,792	22,692,913		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	377,023	746,297		
53	Income Taxes-Federal (409.2)	262-263	-7,631,612	1,788,036		
54	Income Taxes-Other (409.2)	262-263	-533,991	-1,941,466		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	6,674,300	8,755,000		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,608,029	5,112,929		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,722,309	4,234,938		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		30,663,087	71,210,375		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		231,189,035	209,983,057		
63	Amort. of Debt Disc. and Expense (428)		2,844,059	2,815,605		
64	Amortization of Loss on Reaquired Debt (428.1)		1,429,139	2,019,026		
65	(Less) Amort. of Premium on Debt-Credit (429)		637,373	613,119		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		6,818,827	6,556,721		
68	Other Interest Expense (431)		4,737,747	3,413,273		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		14,003,579	14,042,726		
70	Net Interest Charges (Total of lines 62 thru 69)		232,377,855	210,131,837		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		465,780,699	445,329,227		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		465,780,699	445,329,227		

Schedule Page: 114 Line No.: 4 Column: g

Includes depreciation charges of $7,782,561, amortization charges of $2,192,696 and property taxes of $1,927,680 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: h

Includes depreciation charges of $7,808,322, amortization charges of $2,497,135 and property taxes of $1,869,404 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: i

Includes depreciation charges of $861,282, amortization charges of $190,162 and property taxes of $167,477 billed from SCANA Services.

Schedule Page: 114 Line No.: 4 Column: j

Includes depreciation charges of $873,590, amortization charges of $218,807 and property taxes of $163,780 billed from SCANA Services.

Schedule Page: 114 Line No.: 39 Column: c

In SCPSC Docket No. 2014-44-E, the SCPSC authorized the Company to utilize interest rate settlement gains to stabilize the ongoing DSM Lost Revenue through April 2015. Accordingly, in 2015 the Company recognized $5,189,042 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue.

Schedule Page: 114 Line No.: 39 Column: d

In SCPSC Docket No. 2013-382-E, the SCPSC authorized the Company to utilize gains from the settlement of existing interest rate derivatives for the benefit of its customers through offsetting fuel costs. Accordingly, in 2014 the Company recognized $46,436,829 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue to reduce the Company's undercollected fuel costs.

In addition, in SCPSC Docket No. 2014-44-E, the SCPSC authorized the Company to utilize interest rate derivative settlement gains to offset certain Lost Revenue amounts related to the Company's DSM Program for which recovery had been deferred. Accordingly, during 2014 the Company recognized $4,964,918 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue as a result of the Company writing off the related receivable.

The order also authorized the Company to utilize interest rate derivative settlement gains to offset the ongoing DSM Lost Revenues through April 2015. Accordingly, during 2014 the Company recognized $12,601,958 of interest rate derivative settlement gains within Account 421-Miscellaneous Nonoperating Income with such gain recognition being fully offset by a downward adjustment in electric revenue.

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,009,500,783	1,833,229,781
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		470,608,265	445,329,227
17	Appropriations of Retained Earnings (Acct. 436)			
18	See Note 3 to Financial Statements	215.1	-4,750,273	(4,558,225)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-4,750,273	(4,558,225)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31		238	-277,500,000	(264,500,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-277,500,000	(264,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-4,827,566	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,193,031,209	2,009,500,783
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		72,439,245	67,688,972
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		72,439,245	67,688,972
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,265,470,454	2,077,189,755
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		-4,827,566	
51	(Less) Dividends Received (Debit)			
52	Funded Equity Method Losses		4,827,566	
53	Balance-End of Year (Total lines 49 thru 52)			

Schedule Page: 118   Line No.: 50   Column: c

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

Schedule Page: 118   Line No.: 52   Column: c

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	465,780,699	445,329,227
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	246,203,515	268,165,140
5	Amortization of Utiility Plant and Acquisition Adjustment	10,267,867	9,922,388
6	Amortization-Muni Franchise, Unrecovered Plt, & OCI	19,314,459	18,233,861
7	Amortization of Nuclear Fuel	45,687,791	45,229,090
8	Deferred Income Taxes (Net)	-9,862,347	205,942,585
9	Investment Tax Credit Adjustment (Net)	-2,371,100	-3,567,600
10	Net (Increase) Decrease in Receivables	138,604,283	-122,611,335
11	Net (Increase) Decrease in Inventory	-38,218,180	-42,399,578
12	Net (Increase) Decrease in Allowances Inventory	19,389	281,043
13	Net Increase (Decrease) in Payables and Accrued Expenses	161,668,383	-31,734,838
14	Net (Increase) Decrease in Other Regulatory Assets	214,596,402	-338,118,110
15	Net Increase (Decrease) in Other Regulatory Liabilities	17,550,286	-125,206,510
16	(Less) Allowance for Other Funds Used During Construction	24,828,339	27,737,866
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-204,525,159	326,065,464
19	Discount / Premium on Long-Term Debt	-125,075	-146,520
20	Carrying Cost Recovery	-12,330,778	-9,077,954
21	(Gain) / Loss on Disposition of Assets	-4,379,390	-1,000,635
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,023,052,706	617,567,852
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-943,892,487	-932,065,147
27	Gross Additions to Nuclear Fuel	-76,368,193	-9,684,303
28	Gross Additions to Common Utility Plant	-13,825,300	-9,934,828
29	Gross Additions to Nonutility Plant	-1,028,958	-5,114,270
30	(Less) Allowance for Other Funds Used During Construction	-24,828,339	-27,737,866
31	Other (provide details in footnote):		
32	Salvage Received	7,761,255	6,229,336
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,002,525,344	-922,831,346
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Proceeds from Sale of Fixed Assets	7,986,126	6,116,921
39	Investments in and Advances to Assoc. and Subsidiary Companies	-4,061,149	
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Settlement of Interest Rate Swaps	10,278,883	
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Investments in Utility Money Pool	-9,420,000	-80,000,000
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Return of Investments from Utility Money Pool	80,000,000	
54	Other Investments	84,796,178	-106,473,527
55	Settlement of Interest Rate Swaps	-262,844,303	-94,677,082
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,095,789,609	-1,197,865,034
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	500,000,000	300,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Contributions from Parent	204,414,449	88,001,576
66	Net Increase in Short-Term Debt (c)		457,383,000
67	Other (provide details in footnote):		
68	Borrowings from Utility Money Pool	521,400,000	314,087,861
69	Deferred Financing Costs / Long-Term Debt Issuance Costs	-10,729,017	-6,582,313
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,215,085,432	1,152,890,124
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-3,880,073	-6,004,684
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Borrowings from Utility Money Pool	-538,187,861	-297,300,000
78	Net Decrease in Short-Term Debt (c)	-288,422,000	
79	Return of Capital Contributions to Parent	-3,501,500	-6,729,553
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-277,700,000	-252,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	103,393,998	590,855,887
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	30,657,095	10,558,705
87			
88	Cash and Cash Equivalents at Beginning of Period	97,301,378	86,742,673
89			
90	Cash and Cash Equivalents at End of period	127,958,473	97,301,378

Schedule Page: 120 Line No.: 18 Column: b

Includes $141,794 for changes in the Company's net postretirement benefit obligation, ($184,633,752) for the change in fair value of Derivative Instruments,($13,798,937) for Prepayments, ($27,988,645) for Cost of Removal and various other Balance Sheet changes not presented as separate line items.

Schedule Page: 120 Line No.: 18 Column: c

Includes $109,912,772 for changes in the Company's net postretirement benefit obligation, $256,001,555 for the change in fair value of Derivative Instruments,($4,909,664) for Prepayments, ($37,894,053) for Cost of Removal and various other Balance Sheet changes not presented as separate line items.

Schedule Page: 120 Line No.: 26 Column: b

For the twelve months ended December 31, 2015, the Company added $3,072,241 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($2,098,473) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 26 Column: c

For the twelve months ended December 31, 2014, the Company added $3,428,555 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($1,589,135) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: b

For the twelve months ended December 31, 2015, the Company added $564,796 to its Common Utility Plant Property Account (118) and reduced the same account by ($399,018) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 28 Column: c

For the twelve months ended December 31, 2014, the Company added $223,952 to its Common Utility Plant Property Account (118) and reduced the same account by ($311,152) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: b

For the twelve months ended December 31, 2015, the Company added $2,516,410 to its Nonutility Property Account (121) and reduced the same account by ($1,364,577) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 29 Column: c

For the twelve months ended December 31, 2014, the Company added $1,080,603 to its Nonutility Property Account (121) and reduced the same account by ($1,137,201) for capital leases in accordance with USoA General Instruction No. 20.

Schedule Page: 120 Line No.: 54 Column: b

Nuclear Decommissioning Trust	($ 2,086,012)
Collateral Returned - Interest Rate Swaps	934,668,640
Collateral Posted - Interest Rate Swaps	(840,119,762)
Withdrawals from Like Kind Exchange Escrow Account	1,256,673
Deposits to Like Kind Exchange Escrow Account	(8,923,361)
Total	$ 84,796,178

Schedule Page: 120 Line No.: 54 Column: c

Nuclear Decommissioning Trust	($ 1,770,905)
Investment in Refined Coal Partnerships	(5,702,012)
Collateral Returned - Interest Rate Swaps	252,600,134
Collateral Posted - Interest Rate Swaps	(351,318,213)
Withdrawals from Like Kind Exchange Escrow Account	106,993
Deposits to Like Kind Exchange Escrow Account	(389,524)
Total	($106,473,527)

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(2,614,921)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				172,419
3	Preceding Quarter/Year to Date Changes in Fair Value				(703,712)
4	Total (lines 2 and 3)				(531,293)
5	Balance of Account 219 at End of Preceding Quarter/Year				(3,146,214)
6	Balance of Account 219 at Beginning of Current Year				(3,146,214)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				191,077
8	Current Quarter/Year to Date Changes in Fair Value				185,134
9	Total (lines 7 and 8)				376,211
10	Balance of Account 219 at End of Current Quarter/Year				(2,770,003)

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(2,614,921)	[redacted]	[redacted]
2			172,419	[redacted]	[redacted]
3			(703,712)	[redacted]	[redacted]
4			(531,293)	445,329,227	444,797,934
5			(3,146,214)	[redacted]	[redacted]
6			(3,146,214)	[redacted]	[redacted]
7			191,077	[redacted]	[redacted]
8			185,134	[redacted]	[redacted]
9			376,211	465,780,699	466,156,910
10			(2,770,003)	[redacted]	[redacted]

Schedule Page: 122(a)(b) Line No.: 1 Column: e

Lines 1-5 present information for the period 1/1/14 - 12/31/14.

Lines 6-10 present information for the period 1/1/15 - 12/31/15.

Schedule Page: 122(a)(b) Line No.: 1 Column: h

Lines 1-5 present information for the period 1/1/14 - 12/31/14.

Lines 6-10 present information for the period 1/1/15 - 12/31/15.

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses, prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2014.

Schedule Page: 122(a)(b) Line No.: 3 Column: e

Reflects amounts recognized in OCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2014(as applicable).

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Reflects reclassification adjustments of amounts recognized in OCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit cost in 2015.

Schedule Page: 122(a)(b) Line No.: 8 Column: e

Reflects amounts recognized in OCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service cost arising during 2015(as applicable).

Schedule Page: 122(a)(b) Line No.: 10 Column: b

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: c

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: d

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: e

Other Comprehensive Income related to deferred employee benefit plan costs.

Schedule Page: 122(a)(b) Line No.: 10 Column: f

Not applicable for respondent.

Schedule Page: 122(a)(b) Line No.: 10 Column: g

Not applicable for respondent.

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

The basic financial statements shown on pages 110 through 122 are prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). The significant differences from the GAAP requirements are related to the classification of certain assets and liabilities to include the classification of the current portion of certain regulatory assets, the classification of the current portion of long term debt, the classification of certain deferred income taxes, the classification of cost of removal and the classification of debt issuance costs. In addition, the accounts of South Carolina Generating Company, Inc. (GENCO) are not consolidated herein, whereas they are consolidated for GAAP reporting purposes.

These notes are based on the notes contained in South Carolina Electric & Gas Company's (SCE&G) Annual Report on Form 10K filed with the Securities and Exchange Commission and reflect certain reclassifications from the Uniform System of Accounts presentation shown on pages 110 through 122. As such, certain amounts included in these notes will be different from amounts shown on pages 110 through 122.

Management has evaluated the impact of events occurring after December 31, 2015 up to February 26, 2016, the date that SCE&G's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 15, 2016. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in South Carolina Fuel Company (Fuel Company) which is considered to be a variable interest entity, and accordingly, the accompanying financial statements include the accounts of SCE&G and Fuel Company. The equity interests in Fuel Company are held solely by SCANA, SCE&G's parent.

Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

In April 2015, the Financial Accounting Standards Board (FASB) issued accounting guidance intended to simplify the presentation of debt issuance costs by requiring that such costs be deducted from carrying amounts related to debt when presented in the balance sheet. As permitted, SCE&G adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $28 million of unamortized debt issuance costs were reclassified to long-term debt, and certain amounts in Note 4 and Note 12 were also reclassified for comparative periods. The effect of adoption on SCE&G's results of operations and cash flows was not significant.

In November 2015, the FASB issued accounting guidance intended to simplify the presentation of deferred tax assets and deferred tax liabilities by netting and classifying them as noncurrent on the statement of financial position. As permitted, SCE&G early adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $27.6 million of net deferred tax liabilities previously classified in current liabilities were reclassified to long-term liabilities. The effect of adoption on SCE&G's results of operations and cash flows was not significant.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and allowance for funds used during construction (AFC), are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. SCE&G calculated AFC using average composite rates of 5.6% for 2015, 6.5% for 2014 and 6.9% for 2013. These rates do not exceed the maximum allowable rate as calculated under United States Federal Energy Regulatory Commission (FERC) Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the Public Service Commission of South Carolina (SCPSC) and further described in Note 2. The composite weighted average depreciation rates for utility plant assets were 2.55% in 2015, 2.85% in 2014 and 2.96% in 2013.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the United States Department of Energy (DOE) under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of V. C. Summer Nuclear Station 1 (Summer Station). In addition, SCE&G will jointly own and will be the operator of Nuclear Units 2 and 3 being designed and constructed at the site of Summer Station (New Units). Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2015		2014	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 620.4 million	—	$ 578.3 million	—
Construction work in progress	$ 214.6 million	$ 3.4 billion	$ 199.3 million	$ 2.7 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from South Carolina Public Service Authority (Santee Cooper) for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $178.8 million at December 31, 2015 and $88.9 million at December 31, 2014.

Plant to be Retired

At December 31, 2014, SCE&G expected to retire three units that are or were coal-fired by 2020, which was prior to the end of the previously estimated useful lives over which the units were being depreciated. As such, these units were identified as Plant to be Retired. Subsequently, these units were converted to be gas-fired. In the third quarter of 2015, in connection with the adoption of a customary depreciation study and related analysis (see Note 2), SCE&G determined that these units would not likely be retired by 2020, and their depreciation rates were set to recover the units' net carrying value over their respective revised useful lives. Accordingly, the net carrying value of these units is no longer classified as Plant to be Retired at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the balance sheet. Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2015 and 2014, SCE&G incurred $16.5 million and $17.3 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, effective January 1, 2013, SCE&G accrues $1.4 million per month for its portion of the nuclear refueling outages that are scheduled for the spring of 2014 through the spring of 2020. Total costs for 2014 were $43.7 million, of which SCE&G was responsible for $29.1 million. Total costs for 2015 were $40.2 million, of which SCE&G was responsible for $26.8 million.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each period presented) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

SCE&G is included in the consolidated federal income tax returns of SCANA. Under a joint consolidated income tax allocation agreement, each SCANA subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or record revenue in a period different from the period in which the revenue would be recorded by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations to be refunded to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as receivables or accounts payable, respectively.

Debt Issuance Premiums, Discounts and Other Costs

SCE&G presents long-term debt premiums, discounts and debt issuance costs within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

SCE&G presents the revenues and expenses of its regulated activities (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $101.5 million at December 31, 2015 and $115.8 million at December 31, 2014.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

Customers subject to the purchased gas adjustment (PGA) are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a weather normalization adjustment (WNA) which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented a pilot electric WNA (eWNA) for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

New Accounting Matters

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. SCE&G is required to adopt this guidance in the first quarter of 2018 and early adoption is permitted in the first quarter of 2017. Adoption using a retrospective method is required, with options to elect certain practical expedients or to recognize a cumulative effect in the year of initial adoption. SCE&G has not determined when it will adopt this guidance or what elections it will make. SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other things, the guidance clarifies how to account for a software license element included in a cloud computing arrangement, and makes explicit that a cloud computing arrangement not containing a software license element should be accounted for as a service contract. SCE&G has determined that this guidance, when adopted in the first quarter of 2016, will not significantly impact SCE&G's results of operations, cash flows or financial position.

In July 2015, the FASB issued accounting guidance intended to simplify the subsequent measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. SCE&G expects to adopt this guidance when required in the first quarter of 2017. SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In January 2016, the FASB issued accounting guidance intended to clarify the classification and measurement of financial instruments and financial liabilities, among other things. SCE&G expects to adopt this guidance when required in the first quarter of 2018. SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over twelve months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily of the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for year beginning in 2019. SCE&G has not determined what impact this guidance will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to a November 2013 SCPSC accounting order, SCE&G's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act of 1982 (Nuclear Waste Act) for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the United States Court of Appeals for the District of Columbia (Court of Appeals), the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties concerning SCE&G's petition for approval to participate in a Distributed Energy Resource (DER) program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5

Megawatts (MW) by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. SCE&G is to make a good faith effort to have at least 30 MW of utility-scale solar capacity in service by the end of 2016.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

In October 2015, the SCPSC initiated its 2016 annual review of base rates for fuel costs. A public hearing for this annual review was held on April 7, 2016 and final ruling from the SCPSC is pending.

On March 4, 2016, SCE&G filed a request with the SCPSC to adjust its rate rider related to pension costs from $0.00004 to $0.00087 per kilowatt hour.

Electric - Base Rates

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, South Carolina Office of Regulatory Staff (ORS) and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

Pursuant to an SCPSC order, SCE&G removes from rate base deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $9.5 million and $5.8 million during 2015 and 2014, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of demand reduction and energy efficiency programs (DSM Programs) for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G's request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

In January 2016, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would allow recovery of $37.6 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric – Base Load Review Act (BLRA)

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Through 2015, requested rate adjustments have been based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2015	2.6%	$64.5 million
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million

In September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed. See Note 10.

Gas

The Natural Gas Rate Stabilization Act (RSA) is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2015	No change	—
2014	0.6% Decrease	$ 2.6 million
2013	No change	—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2015**	**2014**
Regulatory Assets:		
Accumulated deferred income taxes	$ 276	$ 261
Asset Retirement Obligations (ARO) and related funding	370	333
Deferred employee benefit plan costs	294	309
Deferred losses on interest rate derivatives	526	445
Unrecovered plant	127	137
Environmental remediation costs	35	36
DSM Programs	61	56
Other	128	128
Total Regulatory Assets	$ 1,817	$ 1,705
Regulatory Liabilities:		
Asset removal costs	491	476
Deferred gains on interest rate derivatives	96	82
Other	18	21
Total Regulatory Liabilities	$ 605	$ 579

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to AFC and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G will amortize these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recoverable over periods of up to approximately 24 years.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2015 SCPSC order, deferred costs are currently being recovered over approximately five years through an approved rate rider.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2015 and 2014. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2015 and 2014.

SCE&G's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015 and 2014, retained earnings of approximately $72.4 million and $67.7 million, respectively, were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Total long-term debt, net reflects the retrospective adoption of accounting guidance for unamortized debt issuance costs in the fourth quarter of 2015 (see Note 1). Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2015		2014	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
First Mortgage Bonds (secured)	2018 - 2065	$ 4,340	5.78%	$ 3,840	5.56%
Industrial and Pollution Control Bonds (a)	2028 - 2038	89	3.42%	89	3.42%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other	2016 - 2027	16	2.63%	14	2.63%
Total debt		4,545		4,043	
Current maturities of long-term debt		(104)		(3)	
Unamortized premium, net		2		5	
Unamortized debt issuance costs		(31)		(28)	
Total long-term debt, net		$ 4,412		$ 4,017	

(a) Includes variable rate debt of $34.6 million at December 31, 2015 (rate of 0.03%) and 2014 (rate of 0.04%), which are hedged by fixed swaps.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Long-term debt maturities will be $104 million in 2016, $3 million in 2017, $553 million in 2018, $2 million in 2019 and $2 million in 2020.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Lines of Credit (LOC) and Short-Term Borrowings

At December 31, 2015 and 2014, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	2015	2014
Lines of credit:		
Total committed long-term	$ 1,400	$ 1,400
Outstanding commercial paper (270 or fewer days)	$ 420	$ 709
Weighted average interest rate	0.74%	0.52%
Letters of credit supported by an LOC	$ 0.3	$ 0.3
Available	$ 980	$ 691

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company). In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In December 2015, the term of the five-year agreements was amended and extended by one year, such that they expire in December 2020. The three-year agreement expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company’s commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

SCE&G is obligated with respect to an aggregate of $34.6 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. SCE&G’s interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2015 SCE&G had outstanding money pool investments due from an affiliate of $9 million. At December 31, 2014 SCE&G had outstanding money pool borrowings due to an affiliate of $17 million and money pool investments due from an affiliate of $80 million. On the balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	2015	2014	2013
Current taxes:			
Federal	$ 207	$ 39	$ 145
State	31	(7)	15
Total current taxes	238	32	160
Deferred tax (benefit) expense, net:			
Federal	(9)	151	20
State	(3)	32	6
Total deferred taxes	(12)	183	26
Investment tax credits:			
Amortization of amounts deferred—state	(1)	(1)	(1)
Amortization of amounts deferred—federal	(2)	(3)	(2)
Total investment tax credits	(3)	(4)	(3)
Total income tax expense	$ 223	$ 211	$ 183

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2015	2014	2013
Net income	$ 466	$ 446	$ 380
Income tax expense	223	211	183
Total pre-tax income	$ 689	$ 657	$ 563
Income taxes on above at statutory federal income tax rate	$ 241	$ 230	$ 197
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	23	20	17
State investment tax credits (less federal income tax effect)	(6)	(5)	(5)
Allowance for equity funds used during construction	(9)	(10)	(9)
Amortization of federal investment tax credits	(2)	(2)	(2)
Section 41 tax credits	1	(3)	—
Section 45 tax credits	(9)	(9)	(5)
Domestic production activities deduction	(18)	(7)	(11)
Other differences, net	2	(3)	1
Total income tax expense	$ 223	$ 211	$ 183

The tax effects of significant temporary differences comprising SCE&G's net deferred tax liability are as follows:

Millions of dollars	2015	2014
Deferred tax assets:		
Nondeductible accruals	$ 52	$ 46
Asset retirement obligation, including nuclear decommissioning	182	199
Unamortized investment tax credits	15	16
Deferred fuel costs	7	—
Financial instruments	2	—
Other	2	7
Total deferred tax assets	260	268
Deferred tax liabilities:		
Property, plant and equipment	$ 1,546	$ 1,529
Regulatory asset, asset retirement obligation	122	109
Deferred employee benefit plan costs	85	90
Deferred fuel costs	—	28
Regulatory asset, unrecovered plant	49	52
Regulatory asset, net loss on interest rate derivative contracts settlement	—	21
Demand side management costs	23	21
Prepayments	29	25
Other	41	24
Total deferred tax liabilities	1,895	1,899
Net deferred tax liability	$ 1,635	$ 1,631

SCE&G is included in the consolidated federal income tax return of SCANA and files various applicable state and local income tax returns. The Internal Revenue Service (IRS) has completed examinations of SCANA's federal returns through 2004, and SCANA's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2014 as a result of claims discussed below in Changes to Unrecognized Tax Benefits. With few exceptions, SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	2015	2014	2013
Unrecognized tax benefits, January 1	$ 16	$ 3	—
Gross increases-uncertain tax positions in prior period	33	—	—
Gross decreases-uncertain tax positions in prior period	(2)	—	—
Gross increases-current period uncertain tax positions	2	13	$ 3
Unrecognized tax benefits, December 31	$ 49	$ 16	$ 3

During 2013 and 2014, SCE&G amended certain of its tax returns to claim certain tax-defined research and development deductions and credits and its related impact on domestic production activities. SCE&G also made similar claims in filing its 2013 and

2014 returns in 2014 and 2015, respectively. In connection with these federal and state filings, SCE&G recorded an unrecognized tax benefit of $49 million. During 2015, as the IRS' examination progressed, without resolution, SCE&G evaluated and recorded adjustments to its unrecognized tax benefits; however, none of these changes materially affected SCE&G's effective tax rate. If recognized, $17 million of the tax benefits would affect SCE&G's effective tax rate. It is reasonably possible that these tax benefits will increase by an additional $7 million within the next 12 months. It is also reasonably possible that these tax benefits may decrease by $8 million within the next 12 months. No other material changes in the status of SCE&G's tax positions have occurred through December 31, 2015.

SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit, SCE&G has not recorded a material amount of interest income, interest expense, or penalties associated with any uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

SCE&G recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by SCE&G. SCANA’s Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including SCE&G. The Risk Management Committee, which is comprised of certain officers, including SCE&G’s Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, SCE&G may use treasury rate lock or forward starting swap agreements. Pursuant to regulatory orders, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges, and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, in 2013 the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income in 2013, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G’s DSM Program rider, and to apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.235 billion and $1.085 billion at December 31, 2015 and 2014, respectively.

The fair value of derivatives in the balance sheets is as follows:

Fair Values of Derivative Instruments

Millions of dollars	**Balance Sheet Location**	**Asset**	**Liability**
As of December 31, 2015			
Not designated as hedging instruments			
Interest rate contracts	Other current assets	$ 10	
	Other deferred debits and other assets	5	
	Derivative financial instruments		$ 33
	Other deferred credits and other liabilities		22
Total		$ 15	$ 55
As of December 31, 2014			
Not designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 207
	Other deferred credits and other liabilities		17
Total			$ 224

The effect of derivative instruments on the statements of income is as follows:

Derivatives in Cash Flow Hedging Relationships		**Gain (Loss) Reclassified from Deferred Accounts into Income (Effective Portion)**	
Millions of dollars	**Gain (Loss) Deferred in Regulatory Accounts (Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2015			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2014			
Interest rate contracts	$ —	Interest expense	$ (1)
Year Ended December 31, 2013			
Interest rate contracts	$ 100	Interest expense	$ (2)

As of December 31, 2015, SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.1 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gains (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments		**Gain Reclassified from Deferred Accounts into Income**	
Millions of dollars	**Gain or (Loss) Deferred in Regulatory Accounts**	**Location**	**Amount**
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64
Year Ended December 31, 2013			
Interest rate contracts	$ 39	Other income	$ 50

The gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2015, SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $0.6 million as an increase to interest expense.

Credit Risk Considerations

SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. SCE&G uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of SCE&G’s derivative instruments contain contingent provisions that require SCE&G to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2015 and 2014, SCE&G had posted $3.4 million and $107.1 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Other Current Assets on the balance sheet. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the balance sheet. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and 2014, SCE&G would have been required to post an additional $43.6 million and $125.9 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2015 and 2014, are $47.0 million and $233.0 million, respectively.

In addition, as of December 31, 2015 and December 31, 2014, SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and December 31, 2014, SCE&G could request $7.3 million and $- million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2015 and December 31, 2014 is $7.3 million and $- million, respectively.

Information related to SCE&G's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets				Gross Amounts Not Offset in the Statement of Financial Position		
Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2015						
Interest rate	$ 15	—	$ 15	$ (8)	—	$ 7

Balance sheet location		
	Other current assets	$ 10
	Other deferred debits and other assets	5
	Total	$ 15

As of December 31, 2014 SCE&G had no derivative assets.

Offsetting Derivative Liabilities

Millions of dollars	Gross Amount of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2015						
Interest rate	$ 55	—	$ 55	$ (8)	$ (3)	$ 44
Balance sheet location	Derivative financial instruments		$ 33			
	Other deferred credits and other liabilities		22			
	Total		$ 55			
As of December 31, 2014						
Interest rate	$ 224	—	$ 224	—	$ (98)	$ 126
Balance sheet location	Derivative financial instruments		$ 207			
	Other deferred credits and other liabilities		17			
	Total		$ 224			

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value Level 2 measurements were as follows:

	As of December 31, 2015	As of December 31, 2014
Millions of dollars	**Level 2**	**Level 2**
Assets-Interest rate contracts	$ 15	—
Liabilities-Interest rate contracts	55	$ 224

There were no Level 1 or Level 3 fair value measurements for either period presented and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2015 and December 31, 2014 were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 4,516.3	$ 4,851.3	$ 4,020.2	$ 4,748.2

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA’s noncontributory defined benefit pension plan, which covers regular, full-time employees hired before January 1, 2014. SCANA’s policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA’s pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee’s average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCE&G participates in SCANA’s unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full costs of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumptions based on SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2015**	**2014**	**2015**	**2014**
Benefit obligation, January 1	$ 773.7	$ 695.7	$ 203.2	$ 181.2
Service cost	19.3	16.0	4.3	3.6
Interest cost	32.2	34.1	9.2	9.2
Plan participants' contributions	—	—	1.9	1.7
Actuarial (gain) loss	(47.0)	82.7	(15.4)	18.2
Benefits paid	(54.2)	(54.8)	(10.1)	(9.4)
Amounts funded to parent	—	—	(1.9)	(1.3)
Benefit obligation, December 31	$ 724.0	$ 773.7	$ 191.2	$ 203.2

SCANA adopted new mortality tables and an improvement scale published by the Society of Actuaries in 2014, resulting in an actuarial loss for pension and other post retirement benefit obligations of approximately $22.1 million and $2.1 million, respectively, in 2014. In 2015, based on an evaluation of the mortality experience of the pension plan, SCANA adopted a custom mortality table for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $18.2 million and $1.9 million, respectively, in 2015.

The accumulated benefit obligation for pension benefits was $702.0 million at the end of 2015 and $747.6 million at the end of 2014. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	**2014**	**2015**	**2014**
Annual discount rate used to determine benefit obligation	4.68%	4.20%	4.78%	4.30%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.6 million at December 31, 2015 and by $0.9 million at December 31, 2014. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.6 million at December 31, 2015 and by $0.8 million at December 31, 2014.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Fair value of plan assets	$ 720.1	$ 783.6	—	—
Benefit obligation	724.0	773.7	$ 191.2	$ 203.2
Funded status	$ (3.9)	$ 9.9	$ (191.2)	$ (203.2)

Amounts recognized on the balance sheets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Current liability	—	—	$ (9.6)	$ (8.5)
Noncurrent asset	—	$ 9.9	—	—
Noncurrent liability	$ (3.9)	—	(181.6)	(195.7)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 2.0	$ 1.9	$ 0.7	$ 1.0
Prior service cost	—	0.1	—	—
Total	$ 2.0	$ 2.0	$ 0.7	$ 1.0

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 193.7	$ 191.9	$ 19.9	$ 35.0
Prior service cost	5.2	8.3	0.2	0.5
Total	$ 198.9	$ 200.2	$ 20.1	$ 35.5

In connection with the joint ownership of Summer Station, as of December 31, 2015 and 2014, SCE&G recorded within deferred debits $20.3 million and $17.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2015 and 2014, SCE&G also recorded within deferred debits $13.8 million and $15.1 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	**2015**	**2014**
Fair value of plan assets, January 1	$ 783.6	$ 792.1
Actual return (loss) on plan assets	(9.3)	46.3
Benefits paid	(54.2)	(54.8)
Fair value of plan assets, December 31	$ 720.1	$ 783.6

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. During 2013, in connection with the amendments to the plan, SCANA adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2015 and 2014 and the target allocation for 2016 are as follows:

	Percentage of Plan Assets		
	Target Allocation	**December 31,**	
Asset Category	**2016**	**2015**	**2014**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	34%
Hedge Funds	9%	11%	9%

For 2016, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2015 and 2014, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using					
Millions of dollars	**Total**	**Level 2**	**Level 3**	**Total**	**Level 2**	**Level 3**
	December 31, 2015			*December 31, 2014*		
Mutual funds	$ 496	$ 496	—	$ 566	$ 566	—
Short-term investment vehicles	12	12	—	18	18	—
US Treasury securities	20	20	—	6	6	—
Corporate debt securities	72	72	—	78	78	—
Municipals	13	13	—	14	14	—
Limited partnerships	30	30	—	29	29	—
Multi-strategy hedge funds	77	—	$ 77	73	—	$ 73
	$ 720	$ 643	$ 77	$ 784	$ 711	$ 73

At December 31, 2015, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2015 or 2014.

The pension plan values certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as The New York Stock Exchange and The NASDAQ Stock Market, Inc., where the securities are actively traded. Other mutual funds and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	**2015**	**2014**
Beginning Balance	$ 73	$ 69
Unrealized gains included in changes in net assets	4	4
Purchases, issuances, and settlements	—	—
Ending Balance	$ 77	$ 73

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from SCE&G's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2016	$ 65.1	$ 9.6
2017	63.2	10.3
2018	64.7	10.8
2019	65.3	11.4
2020	65.8	12.0
2021 - 2025	338.3	64.8

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Service cost	$ 19.3	$ 16.0	$ 17.6	$ 4.3	$ 3.6	$ 4.5
Interest cost	32.2	34.1	32.6	9.2	9.2	8.5
Expected return on assets	(52.2)	(56.3)	(51.9)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.5	5.0	0.3	0.3	0.6
Amortization of actuarial losses	11.4	4.0	14.3	1.7	—	2.6
Curtailment	—	—	8.4	—	—	—
Net periodic benefit cost	$ 14.1	$ 1.3	$ 26.0	$ 15.5	$ 13.1	$ 16.2

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in Other Comprehensive Income (OCI), net of tax, were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current year actuarial (gain) loss	$ 0.2	$ 0.2	$ (0.8)	$ (0.3)	$ 0.4	$ (0.4)
Amortization of actuarial losses	(0.1)	(0.1)	(0.1)	—	—	(0.1)
Amortization of prior service cost	(0.1)	(0.1)	—	—	—	—
Total recognized in OCI	$ —	$ —	$ (0.9)	$ (0.3)	$ 0.4	$ (0.5)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current year actuarial (gain) loss	$ 12.2	$ 87.7	$ (137.1)	$ (13.7)	$ 15.5	$ (23.9)
Amortization of actuarial losses	(10.4)	(3.5)	(12.7)	(1.4)	—	(2.2)
Amortization of prior service cost	(3.1)	(2.8)	(4.5)	(0.3)	(0.2)	(0.5)
Prior service cost (credit)	—	—	(7.7)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.1)
Total recognized in regulatory assets	$ (1.3)	$ 81.4	$ (162.0)	$ (15.4)	$ 15.3	$ (26.7)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Discount rate	4.20%	5.03%	4.10%/5.07%	4.30%	5.19%	4.19%
Expected return on plan assets	7.50%	8.00%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.75%/3.00%	3.00%	3.75%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.40%	7.80%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 11.2	$ 0.3
Prior service cost	3.0	0.2
Total	$ 14.2	$ 0.5

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan were $21.8 million in 2015, $20.7 million in 2014 and $18.7 million in 2013 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the SCANA Long-Term Equity Compensation Plan (LTECP) which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2013-2015 and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 award is based on performance over a single three-year cycle. In each performance cycle of the 2013-2015 and 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash and 80% of the awards were granted in performance shares each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For the 2015-2017 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of total shareholder return as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2013-2015 performance cycle were paid in cash totaling $3.7 million at SCANA's discretion in February 2016. Cash-settled liabilities related to earlier performance cycles totaled approximately $6.3 million in 2015, $1.9 million in 2014 and $3.2 million in 2013.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $12.2 million in 2015, $12.6 million in 2014 and $5.5 million in 2013. Such fair value adjustments also resulted in capitalized compensation costs of $0.6 million in 2015, $0.6 million in 2014 and $0.5 million in 2013. At December 31, 2015 SCE&G's unrecognized compensation cost was insignificant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price Anderson Indemnification Act (Price-Anderson), SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the Nuclear Regulatory Commission (NRC) that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with Nuclear Electric Insurance Limited (NEIL). The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with a consortium consisting of Westinghouse Electric Company LLC (WEC) and CB&I Stone & Webster, Inc. (Stone & Webster), a subsidiary of Chicago Bridge & Iron Company (Consortium) for the design and construction of the New Units at the site of Summer Station. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2015, SCE&G's investment in the New Units, including related transmission, totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued Combined Construction and Operating Licenses (COL) in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In October 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule. Shield building construction remains a principal focus area for SCE&G's oversight of the project. The primary critical path for both Unit 2 and Unit 3 runs through the placement of concrete within the containment vessels, the fabrication of shield building panels, the fabrication of the air inlet and tension rings and the completion of shield building construction. For Unit 3, the critical path also runs through the setting of CA20 which is a prerequisite to concrete placement in certain areas of the nuclear island. Plans to accelerate the work needed to permit placing this concrete are underway. In addition, WEC has reached agreement on a mitigation plan to accelerate shield building panel fabrication with one of its subcontractors. Additional mitigation will be required in critical path areas to support the updated substantial completion dates described below.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The result was a revised fully integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is received.

In September 2015, the SCPSC approved an updated BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively, each subject to an 18-month contingency period. In addition, the SCPSC approved certain updated owner's costs ($245 million) and other capital costs ($453 million), of which $539 million were associated with the schedule delays and other contested costs. In this proceeding, SCE&G's total projected capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) were estimated to be $5.2 billion and $6.8 billion, respectively. These projections included cost amounts related to the Revised, Fully-Integrated Construction Schedule for which SCE&G had not accepted responsibility and which were the subject of dispute. As such, these updated milestone schedule and projections did not reflect the resolution of negotiations. In addition, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding the above mentioned disputes, and the Engineering, Procurement and Construction Agreement dated May 23, 2008 (EPC Contract) was amended. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor Corporation as a subcontracted construction manager.

Among other things, the October 2015 Amendment:

(i) resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium, in exchange for (a) an additional cost to be paid by SCE&G and Santee Cooper of $300 million (SCE&G’s 55% portion being $165 million) and an increase in the fixed component of the contract price by that amount, and (b) a credit to SCE&G and Santee Cooper of $50 million (SCE&G’s 55% portion being approximately $27 million) to be applied to the target component of the contract price,

(ii) revised the guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), and capped those aggregate liquidated damages at $463 million per New Unit (SCE&G’s 55% portion being approximately $255 million per New Unit),

(iv) provides for payment to the Consortium of a completion bonus of $275 million per New Unit (SCE&G’s 55% portion being approximately $151 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provides for development of a revised construction milestone payment schedule, with SCE&G and Santee Cooper making monthly payments of $100 million (SCE&G’s 55% portion being $55 million) for each of the first five months following effectiveness, followed by payments made based on milestones achieved, and

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project.

Under the October 2015 Amendment, SCE&G's total estimated project costs increased by approximately $286 million over the $6.8 billion approved by the SCPSC in September 2015, bringing its total estimated gross construction cost of the project (including escalation and AFC) to approximately $7.1 billion.

The payment obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba Corporation, WEC's parent company, reaffirmed its guaranty of WEC's payment obligations. Based on Toshiba's current credit ratings and pursuant to the terms of the EPC Contract, SCE&G has exercised its rights to demand a payment and performance bond from WEC. Such bond will be based on estimated billings and its aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bond. In addition, the EPC Contract provides that upon the request of SCE&G, the Consortium must escrow certain intellectual property and software for SCE&G's benefit to enable completion of the New Units. SCE&G has made such a request to the Consortium.

In addition to the above, the October 2015 Amendment provided for an explicit definition of a Change in Law designed to reduce the likelihood of certain future commercial disputes, and the Consortium also acknowledged and agreed that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19. The October 2015 Amendment also established a dispute resolution board process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction milestone payment schedule referred to above. The EPC Contract was also revised to eliminate the requirement or ability to bring suit before substantial completion of the project.

Finally, the October 2015 Amendment provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G's 55% portion being approximately $3.345 billion). This total amount to be paid would be subject to adjustment for amounts paid since June 30, 2015. Were this fixed price option to be exercised, the aggregate delay-related liquidated damages referred to in (iii) above would be capped at $338 million per unit (SCE&G's 55% portion being approximately $186 million per unit), and the completion bonus referred to in (iv) above would be $150 million per New Unit (SCE&G's 55% portion being approximately $83 million per New Unit). The exercise of this fixed price option would result in SCE&G's total estimated project costs increasing by approximately $774 million over the $6.8 billion approved by the SCPSC in September 2015, and would bring its total estimated gross construction cost (including escalation and AFC) of the project to approximately $7.6 billion.

Resolution of the disputes as described in (i) above, or in the case of the exercise of the fixed price option, would result in estimated project costs above the amounts approved by the SCPSC; however, the guaranteed substantial completion dates fall within the SCPSC approved 18-month contingency periods. SCE&G held an allowable ex parte communication briefing with the SCPSC on November 19, 2015 and, following an evaluation as to whether to exercise the fixed price option, expects to file a petition in 2016, as provided under the BLRA, for an update to the project's estimated capital cost and milestone schedule which would incorporate the impact of the October 2015 Amendment.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes through both the informal and formal procedures and currently anticipates that any costs that arise through such dispute resolution processes (including those reflected in the October 2015 Amendment described above), as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the October 2015 Amendment, which has not been approved by the SCPSC, SCE&G’s currently projected cost would be approximately $750 million to $850 million for the additional 5% interest being acquired from Santee Cooper.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on the guaranteed substantial completion dates provided above, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the Clean Air Act, as amended (CAA), Clean Water Act (CWA), Nuclear Waste Act and Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), among others. In many cases, regulations proposed by such authorities could have a significant impact on SCE&G's financial condition, results of operations and cash flows. In addition, SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCE&G continually monitors and evaluates its current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G participates in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce greenhouse gas (GHG) emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the United States Environmental Protection Agency (EPA) issued a revised standard for new power plants by re-proposing New Source Performance Standards under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per megawatt-hour (MWh) and new natural gas units to meet 1,000 pounds carbon dioxide per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue State Implementation Plans, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the United States Supreme Court (Supreme Court) stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G or its generation operations. SCE&G is currently evaluating the rule and expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, which delayed the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the Clean Air Interstate Rule and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle National Ambient Air Quality Standards. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The Court of Appeals remanded CSAPR, without vacating the rule, to the EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G or its generation operations. Air quality control installations that SCE&G has already completed has positioned it to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's Mercury and Air Toxics Standards (MATS) rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and SCE&G's evaluation of the rule is ongoing. SCE&G's decision to retire certain coal-fired units (see Note 2) and its project to build the New Units along with other actions are expected to result in the SCE&G's compliance with MATS.

On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities under the MATS rule. SCE&G has received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants. On June 29, 2015, the Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of Appeals. The Court noted during remand that EPA has said that it is on track to issue a revised "appropriate and necessary" finding by April 15, 2016. The ruling, however, is not expected to have an impact on SCE&G due to the aforementioned retirements and conversions. SCE&G currently is in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The new federal effluent limitation guidelines for steam electric generating units (ELG Rule) became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G is conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On April 17, 2015, the EPA's final rule for Coal Combustion Residuals (CCR) was published in the Federal Register and became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's coal-fired generating facilities. Although the full effects of this rule are still being evaluated, SCE&G has already closed or has begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. SCE&G does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2015, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and has constructed a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned Manufactured Gas Plant (MGP) sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by the South Carolina Department of Health and Environmental Control and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until at least through 2017 and will cost an additional $18.5 million, which is accrued in Other within Deferred Credits and Other Liabilities on the balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2015, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $34.8 million and are included in regulatory assets.

Claims and Litigation

SCE&G is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on SCE&G’s results of operations, cash flows or financial condition.

Operating Lease Commitments

SCE&G is obligated under various operating leases for rail cars, vehicles, office space, furniture and equipment. Leases expire at various dates through 2051. Rent expense totaled approximately $12.3 million in 2015, $12.0 million in 2014 and $13.6 million in 2013. Future minimum rental payments under such leases will be $4 million in 2016, $2 million in 2017, $1 million in 2018, $1 million in 2019, $1 million in 2020 and $17 million thereafter.

Asset Retirement Obligations

SCE&G recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to SCE&G’s regulated utility operations. As of December 31, 2015, SCE&G has recorded AROs of approximately $176 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $300 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	2015	2014
Beginning balance	$ 521	$ 532
Liabilities incurred	—	3
Liabilities settled	(16)	(6)
Accretion expense	23	24
Revisions in estimated cash flows	(52)	(32)
Ending Balance	$ 476	$ 521

In 2015, revisions in estimated cash flows primarily relate to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study. In 2014 such revisions primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

Prior to January 31, 2015, Carolina Gas Transmission Corporation (CGT) was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in 2015, $30.0 million in 2014 and $33.3 million in 2013. SCE&G's payables to CGT for transportation services were $3.3 million at December 31, 2014, and SCE&G's receivables from CGT related to such transportation services were $1.2 million at December 31, 2014.

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy Marketing, Inc. (SEMI) to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $128.5 million in 2015, $195.7 million in 2014 and $166.9 million in 2013. SCE&G’s payables to SEMI for such purchases were $7.5 million and $12.6 million as of December 31, 2015 and 2014, respectively.

SCE&G purchases all of the electric generation of A. M. Williams Station, which is owned by South Carolina Generating Company, Inc. (GENCO) under a unit power sales agreement. Such unit power purchases, which are included in “Purchased power,” totaled approximately $229.2 million and $231.5 million in 2015 and 2014, respectively. SCE&G had approximately $20.5 million and $21.4 million, payable to GENCO for unit power purchases at December 31, 2015 and 2014, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G’s total purchases from this affiliate were $94.2 million in 2015, $120.4 million in 2014 and $71.8 million in 2013. SCE&G’s total sales to this affiliate were $93.7 million in 2015, $119.8 million in 2014 and $71.5 million in 2013. SCE&G’s payable to this affiliate was insignificant at December 31, 2015 and $13.9 million at December 31, 2014 SCE&G’s receivable from this affiliate was insignificant at December 31, 2015 and $13.8 million at December 31, 2014.

SCANA Services, for itself and its parent company, provides the following services to SCE&G, which are rendered at direct or allocated cost: information systems services, telecommunications services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, general administrative services and retirement benefits. In addition, SCANA Services processes and pays invoices for SCE&G and is reimbursed. Costs for these services totaled $295.5 million in 2015, $294.9 million in 2014 and $276.0 million in 2013. SCE&G's payables to SCANA Services for these services were $56.3 million and $46.4 million at December 31, 2015 and 2014, respectively.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs are described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

SCE&G’s reportable segments follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein.

Electric Operations primarily generates, transmits, and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution purchases and sells natural gas, primarily at retail, and is regulated by the SCPSC.

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, SCE&G does not allocate interest charges, income tax expense, earnings available to common shareholder or assets other than utility plant to its segments. Intersegment revenue and interest income were not significant. SCE&G’s deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to AROs, and totals not allocated to other segments.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Total
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	837	58	—	895
Interest Expense	2	—	$ 230	232
Depreciation and Amortization	259	28	—	287
Segment Assets	10,274	757	3,151	14,182
Expenditures for Assets	1,080	57	(136)	1,001
Deferred Tax Assets	—	n/a	—	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	730	62	—	792
Interest Expense	1	—	$ 209	210
Depreciation and Amortization	281	27	—	308
Segment Assets	9,547	721	3,203	13,471
Expenditures for Assets	925	55	(57)	923
Deferred Tax Assets	4	n/a	(4)	—
2013				
External Revenue	$ 2,431	$ 414	—	$ 2,845
Operating Income	644	58	—	702
Interest Expense	2	—	$ 198	200
Depreciation and Amortization	276	26	—	302
Segment Assets	8,864	686	2,530	12,080
Expenditures for Assets	900	45	51	996
Deferred Tax Assets	9	n/a	(9)	—

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $213 million and $192 million in 2015 and 2014, respectively (net of capitalized interest of $14 million in 2015 and 2014).

Income taxes paid: $87 million and $174 million in 2015 and 2014, respectively.
Income taxes received: $84 million and $- in 2015 and 2014, respectively.

Noncash Investing and Financing Activities:
Accrued construction expenditures: $225 million and $151 million in 2015 and 2014, respectively.
Capital leases expenditures: $6 million and $5 million in 2015 and 2014, respectively.

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2015					
Total operating revenues	$ 772	$ 709	$ 806	$ 643	$ 2,930
Operating income	227	208	298	162	895
Earnings Available to Common Shareholder	122	107	164	73	466
2014					
Total operating revenues	$ 859	$ 698	$ 812	$ 722	$ 3,091
Operating income	230	135	263	164	792
Earnings Available to Common Shareholder	123	96	154	72	445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	10,100,717,022	8,766,747,804
4	Property Under Capital Leases	13,120,896	11,839,029
5	Plant Purchased or Sold		
6	Completed Construction not Classified	311,354,241	279,322,350
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,425,192,159	9,057,909,183
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	3,990,834,928	3,960,026,369
12	Acquisition Adjustments	31,597,076	31,360,826
13	Total Utility Plant (8 thru 12)	14,447,624,163	13,049,296,378
14	Accum Prov for Depr, Amort, & Depl	4,149,318,951	3,579,007,387
15	Net Utility Plant (13 less 14)	10,298,305,212	9,470,288,991
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,950,401,242	3,507,257,793
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	193,202,143	66,141,791
22	Total In Service (18 thru 21)	4,143,603,385	3,573,399,584
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	5,715,566	5,607,803
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,149,318,951	3,579,007,387

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South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,000,412,272				333,556,946	3
155,075				1,126,792	4
					5
28,002,979				4,028,912	6
					7
1,028,570,326				338,712,650	8
					9
					10
15,857,491				14,951,068	11
236,250					12
1,044,664,067				353,663,718	13
401,550,848				168,760,716	14
643,113,219				184,903,002	15
					16
					17
391,508,420				51,635,029	18
					19
					20
9,934,665				117,125,687	21
401,443,085				168,760,716	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
107,763					32
401,550,848				168,760,716	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	1,924,626	7,317,666
3	Nuclear Materials	129,485,531	15,459,559
4	Allowance for Funds Used during Construction	1,311,204	1,159,213
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	132,721,361	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	116,157,676	76,267,304
9	In Reactor (120.3)	222,874,273	75,496,445
10	SUBTOTAL (Total 8 & 9)	339,031,949	
11	Spent Nuclear Fuel (120.4)	598,661,721	75,332,107
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	741,106,879	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	329,308,152	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	6,668,160	2,574,132	2
	68,440,525	76,504,565	3
	387,761	2,082,656	4
			5
		81,161,353	6
			7
	75,496,445	116,928,535	8
	75,332,106	223,038,612	9
		339,967,147	10
		673,993,828	11
			12
-45,687,791		786,794,670	13
		308,327,658	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 2 Column: e

Total fabrication transferred from Batch 25 In-process to Batch 25 Stock; true-up invoices relating to Batches 23 and 24 transferred from respective Batch In-process to Stock.

Schedule Page: 202 Line No.: 3 Column: e

Total nuclear materials transferred from Batch 25 In-process to Batch 25 Stock.

Schedule Page: 202 Line No.: 4 Column: e

Total Allowance for Funds Used During Constuction transferred from Batch 25 In-process to Batch 25 Stock.

Schedule Page: 202 Line No.: 8 Column: e

Total amount transferred from Batch 25 Stock to Batch 25 In-reactor; true-up invoices relating to Batches 23 and 24 transferred from respective Batch Stock to In-reactor.

Schedule Page: 202 Line No.: 9 Column: e

Amount transferred from Batch 22 In-reactor to Batch 22 Spent Fuel.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	14,989	
3	(302) Franchises and Consents	13,208,505	
4	(303) Miscellaneous Intangible Plant	64,709,088	2,493,412
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	77,932,582	2,493,412
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,561,299	8,031
9	(311) Structures and Improvements	247,837,800	12,272,351
10	(312) Boiler Plant Equipment	1,052,078,680	25,255,632
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	422,196,750	10,788,855
13	(315) Accessory Electric Equipment	79,123,645	8,522,026
14	(316) Misc. Power Plant Equipment	28,310,414	3,149,658
15	(317) Asset Retirement Costs for Steam Production	51,141,785	-528,121
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,894,250,373	59,468,432
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	880,612	
19	(321) Structures and Improvements	277,811,939	3,349,938
20	(322) Reactor Plant Equipment	475,249,540	32,341,598
21	(323) Turbogenerator Units	97,859,055	13,133,546
22	(324) Accessory Electric Equipment	101,500,573	10,427,493
23	(325) Misc. Power Plant Equipment	105,975,619	4,789,365
24	(326) Asset Retirement Costs for Nuclear Production	43,803,621	-35,355,676
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,103,080,959	28,686,264
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	29,442,650	
28	(331) Structures and Improvements	49,395,872	170,418
29	(332) Reservoirs, Dams, and Waterways	443,421,988	837,418
30	(333) Water Wheels, Turbines, and Generators	85,536,537	1,076,873
31	(334) Accessory Electric Equipment	20,631,411	6,522,207
32	(335) Misc. Power PLant Equipment	9,642,122	287,778
33	(336) Roads, Railroads, and Bridges	1,817,517	
34	(337) Asset Retirement Costs for Hydraulic Production	-18,514	-22,409
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	639,869,583	8,872,285
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,917,986	
38	(341) Structures and Improvements	40,918,411	368,932
39	(342) Fuel Holders, Products, and Accessories	8,168,567	27,958
40	(343) Prime Movers	587,357,900	1,383,278
41	(344) Generators	92,574,509	1,827,477
42	(345) Accessory Electric Equipment	52,004,969	9,822,757
43	(346) Misc. Power Plant Equipment	1,687,953	104,992
44	(347) Asset Retirement Costs for Other Production	9,483,629	-15,863,255
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	795,113,924	-2,327,861
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,432,314,839	94,699,120

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			14,989		2
			13,208,505		3
3,011,879			64,190,621		4
3,011,879			77,414,115		5
					6
					7
			13,569,330		8
337,920		18,751	259,790,982		9
5,595,196			1,071,739,116		10
					11
3,846,230			429,139,375		12
785,045			86,860,626		13
459,350		15,497	31,016,219		14
29,212,665			21,400,999		15
40,236,406		34,248	1,913,516,647		16
					17
			880,612		18
90,778			281,071,099		19
1,438,010			506,153,128		20
7,723			110,984,878		21
			111,928,066		22
152,730			110,612,254		23
			8,447,945		24
1,689,241			1,130,077,982		25
					26
5,657		-20	29,436,973		27
14,722			49,551,568		28
9,084			444,250,322		29
223,646			86,389,764		30
781,763			26,371,855		31
61,585			9,868,315		32
			1,817,517		33
			-40,923		34
1,096,457		-20	647,645,391		35
					36
		339	2,918,325		37
154,246			41,133,097		38
15,502			8,181,023		39
5,527,929			583,213,249		40
189,278			94,212,708		41
152,725			61,675,001		42
6,853			1,786,092		43
			-6,379,626		44
6,046,533		339	786,739,869		45
49,068,637		34,567	4,477,979,889		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	78,709,006	5,293,184
49	(352) Structures and Improvements	4,689,372	157,978
50	(353) Station Equipment	434,804,384	13,603,814
51	(354) Towers and Fixtures	5,414,270	
52	(355) Poles and Fixtures	320,921,035	39,643,092
53	(356) Overhead Conductors and Devices	187,862,571	25,581,148
54	(357) Underground Conduit	20,724,924	
55	(358) Underground Conductors and Devices	55,524,865	7,094,027
56	(359) Roads and Trails	74,386	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,108,724,813	91,373,243
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	52,816,592	576,296
61	(361) Structures and Improvements	4,910,716	
62	(362) Station Equipment	365,581,631	12,003,222
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	419,374,574	20,382,665
65	(365) Overhead Conductors and Devices	458,625,116	22,769,236
66	(366) Underground Conduit	139,579,887	6,081,121
67	(367) Underground Conductors and Devices	408,277,970	24,487,126
68	(368) Line Transformers	442,674,069	15,581,193
69	(369) Services	266,500,049	8,811,427
70	(370) Meters	182,310,627	6,516,438
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	279,823,799	17,820,758
74	(374) Asset Retirement Costs for Distribution Plant	185,550	-24,964
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,020,660,580	135,004,518
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	6,730,374	
87	(390) Structures and Improvements	146,438,648	2,159,725
88	(391) Office Furniture and Equipment	9,691,185	1,799,750
89	(392) Transportation Equipment	18,537,500	2,257,541
90	(393) Stores Equipment	270,242	
91	(394) Tools, Shop and Garage Equipment	3,475,430	420,273
92	(395) Laboratory Equipment	6,076,369	406,737
93	(396) Power Operated Equipment	51,920,337	3,731,318
94	(397) Communication Equipment	9,478,435	703,824
95	(398) Miscellaneous Equipment	5,843,474	286,028
96	SUBTOTAL (Enter Total of lines 86 thru 95)	258,461,994	11,765,196
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	-1,554	-304
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	258,460,440	11,764,892
100	TOTAL (Accounts 101 and 106)	8,898,093,254	335,335,185
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	8,898,093,254	335,335,185

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
17,000		-215,995	83,769,195		48
		-284,146	4,563,204		49
2,644,811		548,904	446,312,291		50
47,628			5,366,642		51
2,139,734	505	-295,106	358,129,792		52
3,021,446		235,265	210,657,538		53
			20,724,924		54
		-2,827	62,616,065		55
	-505	-114	73,767		56
					57
7,870,619		-14,019	1,192,213,418		58
					59
2,993		287,798	53,677,693		60
			4,910,716		61
1,923,463		-273,628	375,387,762		62
					63
4,248,833			435,508,406		64
3,386,468			478,007,884		65
311,310			145,349,698		66
1,778,996			430,986,100		67
4,534,870			453,720,392		68
142,283			275,169,193		69
88,304,174			100,522,891		70
					71
					72
2,794,783			294,849,774		73
			160,586		74
107,428,173		14,170	3,048,251,095		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
29,688		1,995,229	8,695,915		86
662,016		-39,934	147,896,423		87
258,905			11,232,030		88
1,377,121			19,417,920		89
			270,242		90
86,413			3,809,290		91
205,648			6,277,458		92
4,586,629			51,065,026		93
2,790,201			7,392,058		94
133,340			5,996,162		95
10,129,961		1,955,295	262,052,524		96
					97
			-1,858		98
10,129,961		1,955,295	262,050,666		99
177,509,269		1,990,013	9,057,909,183		100
					101
					102
					103
177,509,269		1,990,013	9,057,909,183		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
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44					
45					
46					
47	TOTAL				

Schedule Page: 213   Line No.: 1   Column: a

Carolina Gas Transmission Corporation (an associated company until sold by SCANA in January 2015 and now operating as Dominion Carolina Gas Transmission LLC (DCGT)) rents office space in a facility that is owned by SCE&G and is classified as electric utility plant on the Company's books. In addition, DCGT rents a field operations building that is owned by SCE&G and is classified as common utility plant on the Company's books.

SCANA Energy Marketing, Inc. (an associated company) also rents office space in a facility that is owned by SCE&G and is classified as common utility plant on the Company's books.

The Company charges a rental fee to SCANA Communications, Inc. (an associated company until sold by SCANA in February 2015 and now operating as Spirit Communications) for communication tower site ground leases.

SCANA Services, Inc.(an associated company) utilizes certain assets, including both office space and equipment, that are owned by SCE&G and classified as electric, gas and common utility plant on the Company's books. SCE&G charges SCANA Services a rental fee for such asset usage.

See Transactions with Associated Companies Schedule on page 429 for additional details.

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Steam Production	
2	Urquhart #2 High Pressure Casing	4,883,447
3	Wateree #2 Flyash Silo	1,652,482
4	Wateree Waste Water Pond	1,470,871
5	Cope SCR Catalyst	1,152,346
6	Wateree #1 Damper Seal Air Fans	597,519
7	Wateree Mist Eliminator System	578,657
8	Wateree #2 Dry Flyash Conversion	519,880
9	Urquhart #3 480/208 Breakers	424,351
10	Cope DCS Hardware	402,893
11	Cope Dual Fuel Firing Systems	333,878
12	Cope Act Carbon Inject Tie-in Pipe	302,514
13	Jasper Steam B Condensate Pump	259,304
14	Wateree #1 Boiler Ignitors	255,820
15	Cope Pug Mills	254,321
16	Minor Steam Production	2,367,114
17	Nuclear Production	
18	VCS #2 and #3 Work Order	3,365,880,700
19	VCS #1 Dry Cask Storage Facilty (ISFSI)	40,224,025
20	VCS #1 RV Head Replacement	25,209,196
21	VCS #1 NFPA 805 - Circuit Protection	11,551,721
22	VCS #1 NFPA 805 - Communications System	8,957,416
23	VCS #1 Redundant Instrument Loop	7,269,437
24	VCS #1 Fukushima FLEX Response Strategy	5,119,679
25	VCS #1 RBCU Industrial Coolers	4,400,700
26	VCS #1 NFPA 805 - Hazard Protection	3,309,504
27	VCS #1 Chemical Treatment Equipment	3,274,468
28	VCS #1 Flex Equipment Storage Building	2,770,697
29	VCS #1 S/R Bravo Chiller Replacenment	2,581,197
30	VCS #1 Bravo CW Pump Housing Repl.	2,567,972
31	VCS #1 New CW Pump Shaft & Can	2,341,832
32	VCS #1 EFW System Flow Control - CIPP	2,314,352
33	VCS #1 Combined Maintenance Shop	2,284,850
34	VCS #1 EEB Elec. FLEX Support Functions	2,067,554
35	VCS #1 AB Truck Bay LWPS Modification	1,771,524
36	VCS #1 Spent Fuel Storage Canisters	1,398,683
37	VCS #1 S/R Charlie Chiller Replacement	1,272,111
38	VCS #1 Incore Flux Thimble Replacement	1,098,904
39	VCS #1 S/R PORV Controls	1,060,303
40	VCS #1 Waste Water Treatment Outfall 005	1,026,674
41	VCS #1 Replace RMWST Heat Tracing	1,020,961
42	VCS #1 EFW Flow Control Venturi	670,903
43	TOTAL	3,960,026,369

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	VCS #1 PORV Tailpipe Equalizing Line	654,219
2	VCS #1 FLEX Alternate FW Suction Source	644,979
3	VCS #1 CB Elevator Controls System	612,611
4	VCS #1 Moduflash Replacement	594,739
5	VCS #1 Simplex Equipment Replacement	589,411
6	VCS #1 SIEM Project	560,632
7	VCS #1 Bravo FWP Turbine Blade Repl.	521,240
8	VCS #1 New Plant Support Building	416,569
9	VCS #1 Exhaust Manifold Replacement	351,571
10	VCS #1 Penstock Piping Project	324,348
11	VCS #1 Alpha FWP Turbine Blade Repl.	315,101
12	VCS #1 Site Drainage Security - Additional	302,635
13	VCS #1 B Loop Aux Crane Replacement	268,377
14	VCS #1 Replace CW Screens XRS0005C&E	251,937
15	Minor Nuclear Production	2,712,154
16	Hydro Production	
17	FPS #1 & #2 Calvert Bus Cable	423,465
18	Minor Hydro Production	788,249
19	Other Production	
20	Parr Black Start Standby Generator	1,473,221
21	Urquhart Spare GSU Transformer for 7FA	1,384,735
22	Hagood #6 Turbine Components	1,101,749
23	Urquhart #5 & #6 HRSG Elevator - 2015	346,885
24	Urquhart #5 & #6 HRSG SH Header Supports - 2015	295,040
25	Minor Other Production	722,570
26	Overhead Transmission Lines	
27	Yemassee-Burton 230 (115) kV	12,474,738
28	Graniteville - Aiken 115kV Line #1	6,885,608
29	St. Andrews-Queensboro 115kV Line	3,994,287
30	Thomas Isl.-Jack Primus 115kV R/W	3,107,130
31	Cainhoy 230 kV: Foldin #2, Reterm #1	2,808,434
32	05313A Canadys - Williams 230 kV	1,754,032
33	Gills Creek 115kV Tap, Prj #0056B	962,429
34	Lyles - Williams Street 115kV Line	894,656
35	Faber Place - James Island 115kV	756,369
36	Thomas Is.-Jack Primus115 #0270B	611,563
37	AMW - Mt Pleasant #2 Line - Reterm.	528,748
38	CIP-Edenwood 115kV: Rebuilt	506,092
39	Stevens Ck-Thurmond 115kV-Repl Sw.	410,926
40	Williams-DAK 230kV #1&#2: Add OPGW	399,679
41	Summerville-Pepperhill 230kV Line	317,413
42	Victory Gardens-Circle Dr. 115kV	265,750
43	TOTAL	3,960,026,369

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Minor Overhead Transmission Lines	1,531,937
2	Overhead Transmission Lines NND	
3	VCS2-St. George 230 kV Line #1 & #2	26,312,700
4	VCS2-LMT 230kV Line #2	24,381,444
5	VCS1-Killian(Winn-Blythwd)230kV(C)	19,418,898
6	VCS2-St. George 230 kV Line #2	18,386,702
7	VCS1-Killian(Blywd-Killian)230kV(C)	11,763,577
8	VCS1-Killian(WinnJct-Winn)230kV(C)	11,325,306
9	VCS2-St. George 230 kV Line #1/#2	10,724,749
10	Canadys-Sumter 230 kV	10,498,577
11	VCS2-St. George 230 kV Line #1 & #2	7,937,345
12	Saluda River-Lyles 230kV BLRA	7,370,967
13	VCS2-St. George 230 kV Line #1	6,247,828
14	St George-Summerville #1 230kV BLRA	5,967,082
15	Denny Terrace-Lyles 230 kV	5,229,594
16	Proj 94Q:Saluda Hyd-Newberry 115kV	4,251,338
17	VCS1-Killian 230kV Line: R/W (C)	4,012,716
18	VCS2-St. George 230 kV Line #1 & #2	3,243,748
19	VCS2-LMT 230 kV Line #1	3,062,018
20	Reterm DennyTerrace #0090n4	2,827,447
21	VCS1-DT (VCS1-Winn Jct) 230 kV	2,119,731
22	Parr-Winn 115 #1 Reloc Parr-Switch	1,250,799
23	VCS2-St. George 230 kV Line #1 & #2	1,163,724
24	Project 0090M1:Reterm Duke Newport	1,039,572
25	VCS1-Killian(VCS1-WinnJct)230 kV(C)	1,023,943
26	Reterm Ward 230kV #0090N2	950,905
27	McMeekin-Lake Murray Trans. 115 kV	886,899
28	Parr-Midway DC 115 #0091F	835,972
29	Parr-Denny Terrace 115kV #14 Line	765,908
30	VCS2-St. George 230 kV Line #1/#2	750,765
31	Saluda Hydro-LMT 115 kV	661,053
32	Reterm Duke (BR)* #0090N3	474,975
33	Minor Overhead Transmission Lines NND	544,752
34	Overhead Transmission Lines Non BLRA	
35	Saluda Hydro-Williams St. 115 kV	8,913,895
36	St George-Summerville 230kV Line #2	3,106,216
37	VCS2-St.George 1&2 Add ROW	1,258,077
38	Dunbar Rd-Orangeburg 115 kV	511,346
39	VCS-St. George 230 kV Line #1	308,193
40	Minor Overhead Transmission Lines Non BLRA	101,892
41	Transmission Substation	
42	Cainhoy 230-115kV Trans. Sub - Cons	8,515,509
43	TOTAL	3,960,026,369

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Urquhart Add Switch House	2,930,497
2	Summerville Transmission Sub #2071	2,850,235
3	Church Creek: Upgrade Autobank	2,683,822
4	Purch Spare 230/115kV Autobank 3	2,653,918
5	Blythewood 115kV Sw St - Construct	2,443,886
6	Toolebeck Sw. Station: Construct	2,434,319
7	CIP Hut IST/Telecom Equip HW	1,639,533
8	O'burg East Sub:2 230kV Terms	1,400,807
9	Burton Substation - Add 115kV Term.	1,365,015
10	CIP5- Low Impact Site IST/Tele Qtr4	1,329,909
11	CIP Hut Implementation @ Substations	1,219,461
12	Batesburg Trans. Sub: Add Transfmr	744,160
13	AM Williams Station #2541	740,558
14	St George 230kV: #2 Sum'ville Term	554,268
15	McCormick Trans-Upgd 46kV Cap Bank	503,563
16	Wateree Station 230kV Sub #2531	480,949
17	Saluda Hyd Sub: Ugd 115 Term to SRT	407,639
18	Jasper:Add back-to-back PRCB	265,371
19	Edmund 115KV: Add Capacitor	254,221
20	Minor Transmission Substation	2,918,215
21	Transmission Substation NND	
22	Saluda River 230/115kV: Construct	12,325,344
23	St. George 230kV Sw Sta - Construct	6,440,987
24	Saluda River 230/115kV Sub Site	3,355,688
25	Various 115kv PRCB's: Upgrade	708,914
26	Saluda Hydro Sub: Upgrade 115kV Bus	659,877
27	Killian-Add 1 230KV Terminal-VCS 1	491,498
28	Lake Murray Trans: Add 230kV Term	443,636
29	Parr Steam - Reterminate DT #14	371,767
30	Denny Terrace 230KV Sub. #2045	349,592
31	St. George 230/115kV Sub-PurchaseLand	334,044
32	Lyles 230KV Substation #2202	277,778
33	Minor Transmission Substation NND	631,224
34	Distribution Substation	
35	Gill Creek 115KV Sub-Construct	3,529,692
36	Pine Hill 230-23kV Substation #848	3,492,990
37	Jack Primus 115-23kv Sub: Construct	1,610,816
38	Sewee Sub.No. 807- Construct	1,002,242
39	Parr Hill 115-23kV - Construct	607,964
40	Shell Point: Replace 2nd Failed Xfm	453,753
41	Kempsons Bridge Sub:Repl xfmrs/Impr	342,744
42	ACS RTU Replacement - 2015	327,486
43	TOTAL	3,960,026,369

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Minor Distribution Substation	951,780
2	Customer Substation	
3	Clemson W.T. Sub: Construct 115/23	792,358
4	Huron 230KV Sub. #776 - Rpl bkrs	447,664
5	Purchase Spare 115-4kV, 10.5MVA Transformer	284,997
6	Minor Customer Substation	316,114
7	Overhead Distribution Lines	
8	Mt. Pleasant To Bayview Trans Under	1,216,992
9	Truck Stock - Metro Columbia	823,977
10	Truck Stock - Aiken	787,843
11	Truck Stock - Runey St-Chas.	704,161
12	Truck Stock - Mt Pleasant-Chas	699,277
13	Truck Stock - Rader-Columbia	695,426
14	Truck Stock - Piney Woods Rd.	633,372
15	2015 Langley SCADA	535,080
16	Truck Stock - Johnston	522,068
17	Truck Stock - Summerville	468,630
18	Truck Stock - Lexington	452,675
19	Truck Stock - Beaufort	425,863
20	Truck Stock - Savage Rd-Chas	387,126
21	Truck Stock - Ridgeland	367,653
22	Truck Stock - Chapin	367,462
23	Truck Stock - Barnwell	301,345
24	Minor Overhead Distribution Lines	4,447,737
25	UG Distribution Lines	
26	Chas Eastside Station Rebuild	878,691
27	2015 NP Replacements	563,309
28	EE-Summer's Corner Main Feeder(South)	445,780
29	Dewberry Hotel - UG Service PH 1	273,881
30	The Hotel At Marion Square - UG Service	272,565
31	Minor UG Distribution Lines	2,960,251
32	Land and Structures	
33	Install Sys Prot Training Facility	1,131,513
34	Minor Land and Structures	213,096
35	Transportation & POE	
36	Minor Transportation & POE	20,448
37	Office Furniture and Equipment	
38	Control Room Video Wall Upgrade	1,610,292
39	EMS Upgrade - Hardware	1,020,992
40	Minor Office Furniture and Equipment	78,009
41	Communication Equipment	
42	Minor Communication Equipment	238,176
43	TOTAL	3,960,026,369

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Tools & Test Equipment	
2	AFUDC Adjustments	563,788
3	Minor Tools & Test Equipment	516,939
4	Intangible Plant	
5	VCS - NFPA 805 Software	14,393,339
6	CHAMPS Replacement	3,901,597
7	Software for Cyber Compliance	8,715,240
8	Seismic PRA Project	7,208,489
9	Configuration Mgmt. Software	1,874,993
10	EMS Upgrade - Software	2,654,754
11	Work Management System (WMS)	1,226,246
12	Itron Smart Sync Replacement	922,618
13	Cope DCS Software	519,155
14	OSI PI Software	449,825
15	MRule & ER Software	283,915
16	Minor Intangible Plant	1,126,717
17	Transmission - BLRA-VCS1	
18	VC Summer Sub #2561-Upgrade PrCB's	8,517,116
19	VCS#1-Upgd 2 Terms & Repl Disc Sw	4,235,936
20	VCS#1-Add Term & Repl 2 Disc Sw.	3,834,635
21	VCS1, Bus1: SCPSA Upg 8852 Add 9322	2,958,117
22	VCS1 Upgr 230kv 8902 & 8932	2,955,594
23	Parr Safeguard 115 kV	2,698,972
24	VCS1 Add Pineland Terminal fr VCS1	2,164,611
25	VCS 1 Upgrade Terminal 8832	1,260,856
26	VCS #2 Tie to VCS #1 #0090H	1,092,991
27	Parr 115kV Safeguard - Raise @ VCS	851,870
28	Project #0090J:VCS#2 to VCS#1Bus#3	762,332
29	VCS3 Tie to VCS1 Bus #1: Bus Tie #1	674,583
30	VCS1, Bus 1: SCPSA repl 8863 & LA's	461,794
31	Minor Transmission - BLRA-VCS1	
32	Transmission - Non-BLRA VCS1	
33	VCS1- CIP Hut IST/Tele/Sec Eq HW	1,105,922
34	VCS1 - CIP Hut Implementation@Sub	323,585
35	Minor Transmission - Non-BLRA VCS1	3,834
36	Payroll Overheads and Adjustments	-1,062,129
37		
38		
39		
40		
41		
42		
43	TOTAL	3,960,026,369

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,449,297,294	3,449,297,294		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	214,322,959	214,322,959		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,958,253	3,958,253		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	8,531,150	8,531,150		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	226,812,362	226,812,362		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	172,491,514	172,491,514		
13	Cost of Removal	28,336,625	28,336,625		
14	Salvage (Credit)	3,268,710	3,268,710		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	197,559,429	197,559,429		
16	Other Debit or Cr. Items (Describe, details in footnote):	28,707,566	28,707,566		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,507,257,793	3,507,257,793		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	807,705,495	807,705,495		
21	Nuclear Production	585,224,061	585,224,061		
22	Hydraulic Production-Conventional	301,153,598	301,153,598		
23	Hydraulic Production-Pumped Storage	75,185,148	75,185,148		
24	Other Production	382,819,875	382,819,875		
25	Transmission	331,786,459	331,786,459		
26	Distribution	927,214,475	927,214,475		
27	Regional Transmission and Market Operation				
28	General	96,168,682	96,168,682		
29	TOTAL (Enter Total of lines 20 thru 28)	3,507,257,793	3,507,257,793		

Schedule Page: 219 Line No.: 8 Column: c

Depreciation of Asset Retirement Costs, Distributed Energy Resources property and Cyber Security property recorded as a regulatory asset.

Schedule Page: 219 Line No.: 12 Column: c

Retirements per Page 207, Line 100 column (d)	$177,509,269
Less: Intangible Plant per Page 205, Line 5 column (d)	(3,011,879)
Capital Lease Asset Reductions Recorded in Accordance with USoA General Instruction No. 20 shown as Plant Retirements	(2,005,876)
Total	$172,491,514

Schedule Page: 219 Line No.: 16 Column: c

ARC retirements reclassified to Regulatory Assets	$ 27,305,946
Gain on Disposal on Vehicles	(216,340)
Book Cost of Land Retired	82,294
Transfers and Adjustments	1,535,666
Total	$ 28,707,566

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	APOG, LLC			250
2	Canadys Refined Coal, LLC			1,273,861
3	Louisa Refined Coal, LLC			309,875
4	Brandon Shores Coaltech, LLC			532,410
5	Cope Refined Coal, LLC			
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42	Total Cost of Account 123.1 $ 0		TOTAL	2,116,396

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
		250		1
-2,637,526		659,092		2
-838,969		276,263		3
-1,351,071		459,003		4
			1,078,253	5
				6
				7
				8
				9
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				41
-4,827,566		1,394,608	1,078,253	42

Schedule Page: 224 Line No.: 1 Column: d

Beginning balance was reclassified during 2015 from Account 124 - Other Investments to Account 123.1 - Investment in Subsidiary Companies. Therefore, this beginning balance is reflected in Account 124 and not Account 123.1 on page 110.

Schedule Page: 224 Line No.: 2 Column: d

Beginning balance was reclassified during 2015 from Account 124 - Other Investments to Account 123.1 - Investment in Subsidiary Companies. Therefore, this beginning balance is reflected in Account 124 and not Account 123.1 on page 110.

Schedule Page: 224 Line No.: 2 Column: g

Amount includes additional investments made during the year of $2,022,757.

Schedule Page: 224 Line No.: 3 Column: d

Beginning balance was reclassified during 2015 from Account 124 - Other Investments to Account 123.1 - Investment in Subsidiary Companies. Therefore, this beginning balance is reflected in Account 124 and not Account 123.1 on page 110.

Schedule Page: 224 Line No.: 3 Column: g

Amount includes additional investments made during the year of $805,357.

Schedule Page: 224 Line No.: 4 Column: d

Beginning balance was reclassified during 2015 from Account 124 - Other Investments to Account 123.1 - Investment in Subsidiary Companies. Therefore, this beginning balance is reflected in Account 124 and not Account 123.1 on page 110.

Schedule Page: 224 Line No.: 4 Column: g

Amount includes additional investments made during the year of $1,277,664.

Schedule Page: 224 Line No.: 5 Column: h

In 2012, SCE&G sold its 10% interest in Cope Refined Coal, LLC and is being paid for such interest over future periods. This amount reflects such payment received in 2015 and has been recorded in Account 421 - Miscellaneous Nonoperating Income.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	68,741,416	57,600,683	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	88,633,157	92,694,189	Electric
8	Transmission Plant (Estimated)	6,673,824	8,078,742	Electric
9	Distribution Plant (Estimated)	25,555,795	26,809,680	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	353,195	447,255	Fleet
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	121,215,971	128,029,866	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	8	351	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	189,957,395	185,630,900	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	144,577.20	668,725	45,625.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			27,845.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	6,757.00	19,386		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	137,820.20	649,339	73,470.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	659.50		659.50	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	659.50			
40	Balance-End of Year			659.50	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	659.50	99		
45	Gains	659.50	99		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
45,625.00		45,625.00		1,186,250.00		1,467,702.20	668,725	1
								2
								3
				45,625.00		73,470.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						6,757.00	19,386	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
45,625.00		45,625.00		1,231,875.00		1,534,415.20	649,339	29
								30
								31
								32
								33
								34
								35
659.50		659.50		32,315.50		34,953.50		36
				1,319.00		1,319.00		37
								38
				659.50		1,319.00		39
659.50		659.50		32,975.00		34,953.50		40
								41
								42
								43
				659.50	27	1,319.00	126	44
				659.50	27	1,319.00	126	45
								46

Schedule Page: 228 Line No.: 4 Column: d

Vintage 2016 allowances allocated by the EPA for the CSAPR SO2 Group 2 Program.

Schedule Page: 228 Line No.: 4 Column: j

Vintage 2045 allowances allocated by the EPA for the S02 Acid Rain Program.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	44,826.70	6,807		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	4.00		12,582.00	
5	Returned by EPA	-10,875.00			
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	5,710.90	3		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	GENCO - Associated Co.	495.00			
23					
24					
25					
26					
27					
28	Total	495.00			
29	Balance-End of Year	27,749.80	6,804	12,582.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						44,826.70	6,807	1
								2
								3
						12,586.00		4
						-10,875.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						5,710.90	3	18
								19
								20
								21
						495.00		22
								23
								24
								25
								26
								27
						495.00		28
						40,331.80	6,804	29
								30
								31
								32
								33
								34
								35
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Schedule Page: 229 Line No.: 4 Column: b

Vintage 2015 New Unit Set Aside allowances allocated by the EPA for the CSAPR Nox Ozone Season Program.

Schedule Page: 229 Line No.: 4 Column: d

Vintage 2016 allowances allocated by the EPA for CSAPR Nox Annual and CSAPR Nox Ozone Season Programs.

Schedule Page: 229 Line No.: 5 Column: b

Vintage 2015 allowances removed by the EPA for the CAIR Programs.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant:					
22						
23	Unrecovered Plant related to the					
24	retirement of Canadys Unit No. 1					
25	SCPSC authorization received					
26	12/2012. (Docket No. 2012-218-E,					
27	Order 2012-951) Amortization					
28	over approximately 14 years					
29	beginning 1/2013.	19,761,879	-90,244	407	1,607,593	14,939,100
30						
31	Unrecovered Plant related to the					
32	retirement of Canadys Unit No. 2					
33	and Unit No. 3. SCPSC					
34	authorization received 9/2013.					
35	(Docket No. 2013-276-E, Order					
36	2013-649) Amortization over					
37	approximately 12 years beginning					
38	1/2014.	136,300,617	2,983,200	407	12,270,624	110,736,817
39						
40	Unrecovered Plant associated with					
41	early retirement of coal					
42	equipment at Urquhart Unit No. 3.	557,755				557,755
43						
44	Unrecovered Plant associated with					
45	early retirement of coal					
46	equipment at McMeekin Station.	422,530	23,835			422,530
47						
48						
49	TOTAL	157,042,781	2,916,791		13,878,217	126,656,202

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Rainbow Energy -				
3	System Impact Study	5,635	408/561/926	10,000	253
4					
5	Rainbow Energy -				
6	Facilities Study	2,179	408/561/926	9,750	253
7					
8	Santee Cooper Longpoint -				
9	Facilities Study	2,025	408/561/926	6,200	253
10					
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20					
21	**Generation Studies**				
22	20150224002 System Impact Study	8,811	408/561/926	50,000	253
23	20150623001 System Impact Study	2,916	408/561/926	15,000	253
24	20150224002 Facilities Study	2,563	408/561/926	100,000	253
25	20150623002 System Impact Study	1,117	408/561/926	6,000	253
26	20150623002 Facilities Study	2,231	408/561/926	6,000	253
27	20151013004 System Impact Study			10,000	253
28	20151216001 System Impact Study			10,000	253
29	20150612001 System Impact Study	1,000	408/561/926	6,000	253
30	20150612001 Facilities Study	2,237	408/561/926	6,000	253
31	20150608003 Facilities Study	1,104	408/561/926	5,000	253
32	20150608003 System Impact Study	333	408/561/926	4,500	253
33	20151105001 System Impact Study			2,800	253
34	20151028002 System Impact Study			2,800	253
35	20150710002 System Impact Study	94	408/561/926	1,000	253
36	20150812001 System Impact Study	1,323	408/561/926	6,000	253
37	20150928001 System Impact Study			6,900	253
38	20150812001 Facilities Study			3,000	253
39	20141031002 Feasibility Study	2,422	408/561/926		
40	20150216001 System Impact Study	4,573	408/561/926	15,000	253

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	20141031001 System Impact Study	7,139	408/561/926	12,000	253
23	20141031002 System Impact Study	1,671	408/561/926	12,000	253
24	20141031001 Facilities Study	3,743	408/561/926	6,000	253
25	20141031002 Facilities Study	3,326	408/561/926	12,000	253
26	20150216001 Facilities Study	1,795	408/561/926	9,000	253
27	20151026002 System Impact Study			1,000	253
28	20151026001 System Impact Study			1,000	253
29	20151026003 System Impact Study			1,000	253
30	20141031001 Feasibility Study	2,864	408/561/926		
31	20150224001 System Impact Study	2,429	408/561/926	15,000	253
32	20150108001 Facilities Study	1,146	408/561/926	5,400	253
33	20150506001 System Impact Study	3,266	408/561/926	5,000	253
34	20150224001 Facilities Study	2,267	408/561/926	15,000	253
35	20150506001 Facilities Study	1,270	408/561/926	6,000	253
36	20150812003 System Impact Study	3,028	408/561/926	6,000	253
37	20150812002 System Impact Study	3,000	408/561/926	6,000	253
38	20150918001 System Impact Study	1,871	408/561/926	6,000	253
39	20150812003 Facilities Study	331	408/561/926	4,500	253
40	20150812002 Facilities Study			6,000	253

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	20151030001 System Impact Study			1,000	253
23	20150108001 System Impact Study	2,709	408/561/926	10,000	253
24	20151014001 System Impact Study			1,000	253
25	20151028001 System Impact Study			51,400	253
26	20150216002 Facilities Study	3,789	408/561/926	100,000	253
27	20150623001 Feasibility Study	3,297	408/561/926	10,000	253
28	20150818001 Feasibility Study	4,433	408/561/926	10,000	253
29	20150623001 System Impact Study			50,000	253
30	20151105002 System Impact Study			2,800	253
31	20150216002 System Impact Study	8,514	408/561/926	50,000	253
32	20151016001 System Impact Study			1,000	253
33	20140619001 Facilities Study	12,199	408/561/926		
34	20140619001 System Impact Study	1,454	408/561/926		
35	20151013002 System Impact Study	1,209	408/561/926	4,500	253
36	20151013003 System Impact Study			6,000	253
37	20150706002 Facilities Study	2,439	408/561/926	6,000	253
38	20150730002 Facilities Study			6,000	253
39	20150730001 Facilities Study	232	408/561/926	6,000	253
40	20151124001 System Impact Study			2,800	253

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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20					
21	**Generation Studies**				
22	20151124002 System Impact Study			2,800	253
23	20150615001 Facilities Study			6,000	253
24	20150608002 Facilities Study			4,200	253
25	20150831001 Facilities Study			6,000	253
26	20151013002 Facilities Study			4,700	253
27	20151013003 Facilities Study			4,700	253
28	20151013001 Facilities Study			4,700	253
29	20151106002 System Impact Study			2,800	253
30	20140702001 System Impact Study	(7)	408/561/926		
31	20150218002 System Impact Study	2,631	408/561/926		
32	20150218001 System Impact Study	1,463	408/561/926		
33	20141027002 System Impact Study	2,012	408/561/926		
34	20141027001 System Impact Study	4,250	408/561/566/926		
35	20141118001 Feasibility Study	3,275	408/561/926		
36	20141118002 Feasibility Study	3,368	408/561/926		
37	20141118001 System Impact Study	3,759	408/561/926	12,000	253
38	20141118002 System Impact Study	1,587	408/561/926	12,000	253
39	20141118001 Facilities Study	1,440	408/561/926	6,000	253
40	20141118002 Facilities Study	3,202	408/561/926	12,000	253

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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20					
21	**Generation Studies**				
22	20150529002 Feasibility Study	2,434	408/561/926	8,400	253
23	20150529001 Feasibility Study	1,747	408/561/926	3,600	253
24	20150602001 System Impact Study	2,385	408/561/926	10,500	253
25	20150608004 System Impact Study	2,995	408/561/926	7,500	253
26	20150608002 System Impact Study	2,228	408/561/926	10,500	253
27	20150304003 Facilities Study	1,445	408/561/926	6,000	253
28	20150615001 System Impact Study	1,440	408/561/926	4,500	253
29	20150615002 System Impact Study	2,387	408/561/926	6,000	253
30	20150629001 Feasibility Study	1,755	408/561/926	4,500	253
31	20140702001 Feasibility Study	10,000	561		
32	20150629002 Feasibility Study	1,148	408/561/926	3,000	253
33	20150629003 System Impact Study	1,452	408/561/926	6,000	253
34	20150706001 System Impact Study	1,390	408/561/926	6,000	253
35	20150706002 System Impact Study	1,778	408/561/926	6,000	253
36	20150713001 System Impact Study	1,473	408/561/926	10,000	253
37	20140409001 Facilities Study	691	408/561/566/926		
38	20150423001 Feasibility Study	155	408/561/926		
39	20150423001 System Impact Study	5,613	408/561/926	50,000	253
40	20150423001 Facilities Study			100,000	253

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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20					
21	**Generation Studies**				
22	20150713002 System Impact Study	1,090	408/561/926	6,000	253
23	20150304001 Facilities Study	845	408/561/926	4,800	253
24	20150304002 Facilities Study	724	408/561/926	4,800	253
25	20150730001 System Impact Study	459	408/561/926	6,000	253
26	20150730002 System Impact Study	1,342	408/561/926	6,000	253
27	20150529002 Facilities Study	1,773	408/561/926	7,500	253
28	20150529001 Facilities Study	847	408/561/926	3,000	253
29	20150831001 System Impact Study	1,352	408/561/926	4,500	253
30	20150615002 Facilities Study	1,064	408/561/926	4,500	253
31	20150629001 Facilities Study	974	408/561/926	4,500	253
32	20150629002 Facilities Study	1,294	408/561/926	4,500	253
33	20150629003 Facilities Study	1,138	408/561/926	4,500	253
34	20150930001 System Impact Study	1,209	408/561/926	3,000	253
35	20150706001 Facilities Study	7,605	408/561/926	6,000	253
36	20150713001 Facilities Study	4,059	408/561/926	6,000	253
37	20150713002 Facilities Study	1,011	408/561/926	4,500	253
38	20151013001 System Impact Study	1,209	408/561/926	4,500	253
39	20140702001 Facilities Study	3,744	408/561/926	10,000	253
40	20150304003 System Impact Study	4,987	408/561/926	11,000	253

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
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19					
20					
21	**Generation Studies**				
22	20150218001 Facilities Study	3,012	408/561/926	12,500	253
23	20150218002 Facilities Study	1,298	408/561/926	20,000	253
24	20141027001 Facilities Study	2,750	408/561/926	22,000	253
25	20141027002 Facilities Study	3,377	408/561/926	15,000	253
26	20150304002 System Impact Study	1,378	408/561/926	15,000	253
27	20150304001 System Impact Study	2,108	408/561/926	15,000	253
28	20151106003 System Impact Study			1,000	253
29	20140909001 System Impact Study	1,618	408/561/926	12,000	253
30	20140909001 Facilities Study	2,879	408/561/926	15,000	253
31	20150317001 System Impact Study	3,122	408/561/926	12,000	253
32	20150317001 Facilities Study	1,167	408/561/926	3,600	253
33					
34					
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Schedule Page: 231 Line No.: 3 Column: d

Represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to the applicable expense accounts where the actual charges were incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Schedule Page: 231 Line No.: 6 Column: d

Represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to the applicable expense accounts where the actual charges were incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Schedule Page: 231 Line No.: 9 Column: d

Represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to the applicable expense accounts where the actual charges were incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Schedule Page: 231.6 Line No.: 33 Column: d

Column (d) represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary, an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to the applicable expense accounts where the actual charges were incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Income Taxes	261,597,300	17,330,800	282	3,198,500	275,729,600
2	Amt. Undercollected - Elec. Fuel Adjustment Clause	64,385,693	77,013,426	449/173	141,399,119	
3	Columbia & Charleston Franchise	25,852,935		407	4,183,224	21,669,711
4	Gas Water Heater Rebate Program (2009-2020)	4,336,509	3,376,247	912	3,114,337	4,598,419
5	Decommissioning Asset Ret. Obligation	47,550,088	13,439,112	Various	9,195,255	51,793,945
6	MGP Environmental Remediation	35,523,746	77,394,682	735	78,103,381	34,815,047
7	Deferred ARO Accretion & Depreciation Costs	285,996,690	55,857,456	Various	23,628,318	318,225,828
8	Interest Rate Derivatives	444,644,896	146,968,987	244/427	65,655,725	525,958,158
9	Deferred Employee Benefit Plan Costs-Gas (ASC 715)	29,816,501	29,613,121	Various	29,833,924	29,595,698
10	Deferred Employee Benefit Plan Costs-Elec (ASC 715)	208,237,711	191,071,713	Various	208,393,658	190,915,766
11	Gas Customer Awareness Program (11/2009-10/2018)	828,320	195,654	913	475,293	548,681
12	Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	5,057,782		530	183,815	4,873,967
13	Deferred Capacity Charges (7/2010-7/2020)	2,870,047		555	1,525,713	1,344,334
14	Deferred Capacity Charges	2,010,111	87,200			2,097,311
15	Electric Demand Side Management	61,702,143	22,042,488	254/908	17,642,272	66,102,359
16	Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	8,508,919		555	282,660	8,226,259
17	Economic Development Grants (10/2009-12/2026)	6,140,915		921	747,604	5,393,311
18	Incremental Rtl Elec Rate Case Exp (7/2010-12/2015)	79,442	1,891	928	81,333	
19	Major Maintenance Accrual and Interest	7,518,620	5,667,842	Various	7,550,232	5,636,230
20	Deferred Pension Cost - Gas (11/2013-1/2027)	12,425,621		926	1,029,508	11,396,113
21	Deferred Pension Cost - Electric (1/2013-12/2042)	58,677,262		926	1,987,835	56,689,427
22	Environmental Compliance Studies (7/2010 - 7/2020)	525,255		506	94,783	430,472
23	Deferred Pollution Control Costs -					
24	Wateree (1/2013-9/2040)	27,279,836		407.3	1,061,940	26,217,896
25	Research and Development Grant (1/2013-12/2047)	3,300,000		930.2	100,000	3,200,000
26	Environmental Remediation Cost	909,923	3,652,972	Various	4,197,796	365,099
27	Amount Undercollected - Gas Cost Adjustment	5,751,069	59,124,263	Various	57,855,962	7,019,370
28	Gas WNA Cap - Winter 2012 (11/2012-10/2015)	1,567,619		480/481	1,567,619	
29	Gas WNA Cap - Winter 2015		1,194,644			1,194,644
30	Fukushima Compliance Costs	3,000,000	4,377,442	Various	3,711,796	3,665,646
31	Wholesale Fuel Undercollection	1,372,819	415,858	447	1,788,677	
32	Undercollected Electric Pension Expense		9,159,502	926	3,161,573	5,997,929
33	Deferred Long-Term Capacity Contract	3,130,952	16,399,885	555/565	10,800,000	8,730,837
34	Carrying Costs Accrual	8,742,317	9,490,112			18,232,429
35	Cyber Compliance Costs		994,388			994,388
36	CIPv5 Compliance Costs		2,367,253			2,367,253
37	Gas Pipeline Integrity Costs	448,495	3,588,807	887	313,524	3,723,778
38	DER and NET Metering Costs	23,866	707,645			731,511
39	Coal Supply Contract Termination (5/2015-12/2016)		2,000,000	501	800,000	1,200,000
40	Nuclear Refueling Outage Costs		3,903,725			3,903,725
41						
42						
43						
44	**TOTAL :**	1,629,813,402	757,437,115		683,665,376	1,703,585,141

Schedule Page: 232 Line No.: 2 Column: a

SCPSC Docket No. 2015-2-E

Schedule Page: 232 Line No.: 3 Column: a

SCPSC Docket No. 2002-223-E

Amounts are being amortized through cost of service rates over approximately twenty years.

Schedule Page: 232 Line No.: 4 Column: a

SCPSC Docket No. 89-245-G
SCPSC Docket No. 2008-155-G

Schedule Page: 232 Line No.: 5 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 6 Column: a

SCPSC Docket No. 2005-113-G

Schedule Page: 232 Line No.: 7 Column: a

SCPSC Docket No. 2003-84-E

Schedule Page: 232 Line No.: 8 Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

Schedule Page: 232 Line No.: 11 Column: a

SCPSC Docket No. 2007-418-G

Schedule Page: 232 Line No.: 12 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 13 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 14 Column: a

SCPSC Docket No. 2008-230-E

Schedule Page: 232 Line No.: 15 Column: a

Amortization of deferred balance is a function of customer usage per a Rate Rider mechanism approved by the SCPSC in Docket Nos. 2013-50-E, 2013-208-E, 2014-44-E, and 2015-45-E.

Schedule Page: 232 Line No.: 16 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 17 Column: a

SCPSC Docket No. 2009-497-E
SCPSC Docket No. 2011-264-E
SCPSC Docket No. 2012-246-E

Schedule Page: 232 Line No.: 18 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 19 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 20 Column: a

SCPSC Docket No. 2009-35-G
SCPSC Docket No. 2013-6-G

Schedule Page: 232 Line No.: 21 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 22 Column: a

SCPSC Docket No. 2009-489-E

Schedule Page: 232 Line No.: 24 Column: a

SCPSC Docket No. 2008-393-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 25 Column: a

SCPSC Docket No. 2011-513-E
SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 26 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 232 Line No.: 27 Column: a

SCPSC Docket No. 2015-5-G

Per SCPSC Docket No. 2005-5-G, commodity and demand components of purchased gas cost are now recovered separately. Balances for these components as of December 31, 2015 are as follows:

Commodity	($1,769,255)
Demand	8,788,625
Total	$ 7,019,370

Schedule Page: 232 Line No.: 28 Column: a

SCPSC Docket No. 2012-6-G
SCPSC Docket No. 2014-6-G

Schedule Page: 232 Line No.: 30 Column: a

SCPSC Docket No. 2012-277-E

Schedule Page: 232 Line No.: 32 Column: a

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2014-88-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

Schedule Page: 232 Line No.: 33 Column: a

SCPSC Docket No. 2013-276-E

In the docket referenced above, the SCPSC authorized amortization in the amount of $10.8 million annually. Such amortization will remain in effect until the deferred balance is fully amortized.

Schedule Page: 232 Line No.: 34 Column: a

In SCPSC Docket No. 2013-336-E, the SCPSC approved the exclusion from rate base of ADIT assets associated with the treatment of capitalized interest related to new nuclear construction. The SCPSC also approved the accrual of carrying costs on the balance of the ADIT assets removed from rate base, with such carrying costs being deferred as a regulatory asset.

Schedule Page: 232 Line No.: 35 Column: a

SCPSC Docket No. 2015-372-E

Schedule Page: 232 Line No.: 36 Column: a

SCPSC Docket No. 2014-416-E

Schedule Page: 232 Line No.: 37 Column: a

SCPSC Docket No. 2014-461-G

In the docket referenced above, the SCPSC authorized amortization in a levelized annual amount of $1,881,143 beginning in November 2015.

Schedule Page: 232 Line No.: 38 Column: a

SCPSC Docket No. 2014-246-E
SCPSC Docket No. 2015-54-E

Schedule Page: 232 Line No.: 40 Column: a

SCPSC Docket No. 2012-218-E

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Noncurrent Receivable - Post					
2	Retirement Benefits	32,921,713	24,722,869	Various	23,543,214	34,101,368
3	Charleston Garage Revenue Bond					
4	Long-Term	2,790,070	58,048	143	1,236,057	1,612,061
5	5 year Commitment Fees	5,413,980	1,364,764	427	1,408,900	5,369,844
6	3 Year Commitment Fees	122,935	319,628	427	148,034	294,529
7	Progress Payments/Plant Equipmt	2,037,190	13,855,422	Various	11,197,835	4,694,777
8	Director's Endowment	415,760	7,021	426.5	40,334	382,447
9	Pole Attachment Receivables	721,532	4,485,111	143/589	3,012,963	2,193,680
10	Long Term Power Plant Service					
11	Agreement (2007-2021)	1,492,776	18,558,982	107/553	18,740,182	1,311,576
12	Lease Buyout Costs (2009-2057)	5,467,751		Various	194,250	5,273,501
13	Department of Energy Nuclear					
14	Loan Guarantee Application Fee	1,183,076				1,183,076
15	Workers' Comp Reserve	529,447	230,186	925	361,861	397,772
16	NND Transmission Lines	180,000		107	90,000	90,000
17	Multi-year Cloud Computing					
18	Fees (2014-2017)		323,506	912	193,476	130,030
19	McMeekin Solar Study		116,552			116,552
20	Other	-121,325	27,567,024	Various	27,452,682	-6,983
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47	Misc. Work in Progress	33,262,058				27,490,688
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	86,416,963				84,634,918

Schedule Page: 233 Line No.: 20 Column: f

Credit balance due primarily to CIAC awaiting distribution and clearance to capital work order(s).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Asset Retirement Obligation	147,217,462	140,717,394
3	Other Post Employment Benefits	64,262,400	58,815,900
4	Unamortized Investment Tax Credits	14,430,000	13,633,600
5	Early Retirement Programs	3,653,500	3,492,800
6	Major Maintenance	-2,876,000	-2,155,800
7	Other	-6,871,000	7,125,200
8	TOTAL Electric (Enter Total of lines 2 thru 7)	219,816,362	221,629,094
9	Gas		
10	Other Post Employment Benefits	9,454,500	8,664,800
11	Asset Retirement Obligation	7,566,900	7,950,100
12	Environmental Remediation	-6,822,800	-6,383,900
13	Incentive Compensation	3,883,800	4,134,000
14	Unamortized Investment Tax Credits	1,435,599	973,000
15	Other	3,259,600	2,450,700
16	TOTAL Gas (Enter Total of lines 10 thru 15	18,777,599	17,788,700
17	Other (Specify): Non Operating	48,283,430	36,607,402
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	286,877,391	276,025,196

Notes

Line 7 "Other":

	Balance at Beg. of Year	Balance at End of Year
Reserve for Injuries and Damages	$ 1,059,700	$ 1,924,800
Regulatory Asset/Liability, Interest Rate Derivatives	(21,131,900)	1,984,900
Vacation Accrual	1,760,800	1,909,400
Nuclear Refueling Costs	2,013,200	(1,493,100)
Storm Damage Reserve	2,092,600	1,492,000
Nuclear Fuel	3,792,200	(1,307,100)
Uncollectible Accounts	1,112,300	929,300
Incentive Compensation	897,700	888,500
Long Term Disability	733,000	308,100
All Other	799,400	488,400
Total	($ 6,871,000)	$ 7,125,200

Line 15 "Other" :

	Balance at Beg. of Year	Balance at End of Year
Early Retirement Programs	$ 645,600	$ 628,100
Inventory Capitalization Under 263A	771,400	611,600
Long Term Disability	969,400	353,000
Vacation Accrual	330,600	337,700
Uncollectible Accounts	169,300	204,500
Reserve for Injuries and Damages	178,700	123,400
All Other	194,600	192,400
Total	$ 3,259,600	$ 2,450,700

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line 17 "Other" :	Balance at Beg. of Year	Balance at End of Year
Asset Retirement Obligation	$44,508,520	$33,488,202
Director's Endowment	1,642,500	1,195,800
Early Retirement Programs	884,200	876,400
Other Post Employee Benefits	628,465	428,100
All Other	619,745	618,900
Total	$48,283,430	$36,607,402

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock Issued	50,000,000		
3	Total Common	50,000,000		
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5				
6	Account 204:			
7	Preferred Stock Issued	20,000,000		
8	Total Preferred	20,000,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
40,296,147	576,405,122					2
40,296,147	576,405,122					3
						4
						5
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1,000	100,000					7
1,000	100,000					8
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Schedule Page: 250 Line No.: 2 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: c

No par value

Schedule Page: 250 Line No.: 7 Column: e

These shares are held by SCANA Corporation and do not pay a dividend.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received from Stockholders:	
2	Cash donations by former parent company, General Gas & Electric	
3	Corporation	240,000
4	Equity advance from SCANA to SCE&G from issuance of 2.3 million	
5	shares of common stock (1992)	89,941,500
6	Equity advance from SCANA to SCE&G from issuance of 404,222 shares	
7	of SCANA common stock under the Dividend Reinvestment and Stock	
8	Purchase Plan and 422,082 shares of SCANA common stock under the	
9	Stock Purchase Savings Plan (1992)	36,895,774
10	Equity advance from SCANA to SCE&G from issuance of 529,954 shares	
11	of SCANA common stock under the Dividend Reinvestment and Stock	
12	Purchase Plan and 705,498 shares of SCANA Common Stock under	
13	the Stock Purchase Saving Plan (1993)	58,141,500
14	Equity advance from SCANA to SCE&G from issuance of 595,438 shares	
15	of SCANA common stock under the Dividend Reinvestment and Stock	
16	Purchase Plan and 781,354 shares of SCANA common stock	
17	under the Stock Purchase Savings Plan (1994)	43,425,899
18	Equity advance from SCANA to SCE&G from issuance of 1,434,664	
19	shares of SCANA common stock under the SCANA Investor Plus Plan	
20	and 1,630,993 shares of SCANA common stock under the Stock	
21	Purchase Savings Plan (1996)	53,658,065
22	Equity advance from SCANA to SCE&G from issuance of 4.5 million	
23	shares of SCANA common stock (1995)	85,845,000
24	Equity advance from SCANA to SCE&G from issuance of 1,118,366	
25	shares of SCANA common stock under the SCANA Investor Plus Plan	
26	and 1,393,761 shares of SCANA common stock under the	
27	Stock Purchase Savings Plan (1996)	49,141,871
28	Equity advance from SCANA to SCE&G from issuance of 170,524 shares	
29	of SCANA common stock under the SCANA Investor Plus Plan and	
30	the issuance of 342,409 shares of SCANA common stock under	
31	the Stock Purchase Savings Plan (1997)	12,147,617
32	Reclass of 2001-2003 Capital Contributions from Parent from 211	
33	account "Misc Paid-In Capital"	197,911,200
34	Repayment of Capital Contributions from Parent (2004)	-3,206,660
35	Equity advance from SCANA to SCE&G from issuance of 356,008 shares	
36	of SCANA common stock under the SCANA Investor Plus Plan and	
37	the issuance of 780,472 shares of SCANA common stock under the	
38	Stock Purchase Savings Plan (2004)	41,728,531
39		
40	TOTAL	2,188,167,716

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Reclass of 2005 Capital Contributions from Parent from	
2	account 211 "Misc. Paid in Capital."	4,591,300
3	Equity advance from SCANA to SCE&G from issuance of SCANA common	
4	stock under the SCANA Investor Plus Plan and the Stock Purchase	
5	Saving Plan (2005)	34,697,793
6	Equity advance from SCANA to SCE&G based on SCE&G's funding	
7	requirements	1,294,496,916
8	Income tax benefit true-up	78,259,588
9	Equity advance from SCANA to SCE&G from issuance of SCANA Common	100,500,000
10	stock	
11	Subtotal - Account 208	2,178,415,894
12		
13	Account 209 - Reduction in Par or stated value of Capital Stock	
14	Subtotal - Account 209	
15		
16	Account 210 - Gain on Resale or Cancellation of Reacquired Capital	
17	Stock:	
18		
19	Subtotal - Account 210	
20		
21	Account 211 - Miscellaneous Paid - In - Capital:	
22	Merger of Florence Gas Division	6,284,464
23	Revaluation of fixed capital and related depreciation reserves	
24	(1940)	8,547,035
25	Merger of Lexington Water Power Company (1943)	5,418,114
26	Reserves for amounts in excess of original cost of utility plant	
27	(1943)	-9,547,035
28	Discount on purchase of 20 shares of 5% series, $50 par value	
29	preferred stock (1944)	100
30	Revaluation of Florence-Darlington gas properties (1944)	-276,426
31	Disposition of electric and common plant adjustments (1945)	39,140
32	Disposition of other physical property adjustments (1945)	82,567
33	Disposition of gas plant intangibles (1945)	-644,761
34	Adjustments of 1941 land sales by Lexington Water Power	
35	Company (1949)	12,331
36	Funds received from Script Agent under 1946 Plan for Stock	
37	Distribution by former Parent Company (1952, 1953)	98,308
38	Capital Contributions from Parent (2001)	32,908,300
39	Capital Contributions from Parent (2002)	156,780,200
40	TOTAL	2,188,167,716

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Capital Contributions from Parent (2003)	8,222,700
2	Reclass of 2001-2003 Capital Contributions from Parent to	
3	account 208 "Donations Received from Stockholders" (2004)	-197,911,200
4	Other	-262,015
5	Equity advance representing the true up of the benefit allocation	
6	relating to the SCANA tax benefit	4,591,300
7	Reclass of 2005 Capital Contributions from Parent to	
8	account 208 "Donations Received from Stockholders."	-4,591,300
9	Subtotal - Account 211	9,751,822
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40	TOTAL	2,188,167,716

Schedule Page: 253.1 Line No.: 7 Column: b

During 2015, the Company received equity advances from SCANA in the amount of $200,000,000. The entry was:

Account	Debit	Credit
131 - Cash	$200,000,000	
208 - Donations Received from Stockholders		$200,000,000

Schedule Page: 253.1 Line No.: 8 Column: b

During 2015, the Company recorded the following transactions associated with the income tax benefit allocations from SCANA:

Account	Debit	Credit
208 - Donations Received from Stockholders	$3,501,500	
131 - Cash		$3,501,500

Account	Debit	Credit
131 - Cash	$3,996,281	
208 - Donations Received from Stockholders		$3,996,281

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense, no par value	4,335,379
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22	TOTAL	4,335,379

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2			
3	First Mortgage Bonds:		
4	6.625% Series, due 2032	300,000,000	2,928,187
5			2,397,000 D
6			
7	4.50% Series, due 2064	300,000,000	2,625,000
8			3,186,000 D
9			
10	5.25% Series, due 2035	100,000,000	1,032,840
11			1,821,000 D
12			
13	5.30% Series, due 2033	300,000,000	2,678,847
14			579,000 D
15			
16	5.25% Series, due 2018	250,000,000	2,443,883
17			615,000 D
18			
19	5.80% Series, due 2033	200,000,000	1,785,478
20			646,000 D
21			
22	6.25% Series, due 2036	125,000,000	1,240,777
23			421,250 D
24			
25	6.05% Series, due 2038	250,000,000	2,611,037
26			242,500 D
27			
28	6.05% Series, due 2038	110,000,000	962,500
29			5,365,800 D
30			
31	4.35% Series, due 2042	250,000,000	2,559,708
32			207,500 D
33	TOTAL	4,529,541,381	43,864,328

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
01-31-2002	02-01-2032	01-31-2002	02-01-2032	300,000,000	19,875,000	4
						5
						6
06-01-2014	06-01-2064	06-01-2014	06-01-2064	300,000,000	13,500,000	7
						8
						9
03-08-2005	03-01-2035	03-08-2005	03-01-2035	100,000,000	5,250,000	10
						11
						12
05-21-2003	05-15-2033	05-21-2003	05-15-2033	300,000,000	15,900,000	13
						14
						15
11-06-2003	11-01-2018	11-06-2003	11-01-2018	250,000,000	13,125,000	16
						17
						18
01-23-2003	01-15-2033	01-23-2003	01-15-2033	200,000,000	11,600,000	19
						20
						21
06-27-2006	07-01-2036	06-27-2006	07-01-2036	125,000,000	7,812,500	22
						23
						24
01-14-2008	01-15-2038	01-14-2008	01-15-2038	250,000,000	15,212,725	25
						26
						27
06-24-2008	01-15-2038	06-24-2008	01-15-2038	110,000,000	6,473,500	28
						29
						30
01-30-2012	02-01-2042	01-30-2012	02-01-2042	250,000,000	10,875,000	31
						32
				4,528,955,967	231,189,035	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.35% Series, due 2042	250,000,000	2,559,709
2			-21,570,000 P
3			
4	6.50% Series, due 2018	300,000,000	2,214,194
5			861,000 D
6			
7	6.05% Series, due 2038	175,000,000	1,916,924
8			728,000 D
9			
10	5.50% Series, due 2039	150,000,000	1,517,157
11			1,179,000 D
12			
13	3.22% Series, due 2021	30,000,000	329,625
14			
15	5.45% Series, due 2041	250,000,000	2,187,500
16			917,500 D
17			
18	5.45% Series, due 2041	100,000,000	1,361,577
19			-2,799,000 P
20			
21	4.60% Series, due 2043	400,000,000	4,234,911
22			2,000,000 D
23			
24	5.10% Series, due 2065 (State Commission Order No. 2013-277 Issued 05-09-2013)	500,000,000	4,375,000
25			4,035,000 D
26			
27	Pollution Control Facilities Revenue Bonds:		
28	4% Industrial Revenue, due 2028	39,480,000	426,014
29			-2,694,115 P
30			
31	3.625% Industrial Revenue, due 2033	14,735,000	158,164
32			258,157 D
33	TOTAL	4,529,541,381	43,864,328

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
07-13-2012	02-01-2042	07-13-2012	02-01-2042	250,000,000	10,875,000	1
						2
						3
10-02-2008	11-01-2018	10-02-2008	11-01-2018	300,000,000	19,500,000	4
						5
						6
03-17-2009	01-15-2038	03-17-2009	01-15-2038	175,000,000	10,681,275	7
						8
						9
12-09-2009	12-15-2039	12-09-2009	12-15-2039	150,000,000	8,250,000	10
						11
						12
10-18-2011	10-18-2021	10-18-2011	10-18-2021	30,000,000	966,000	13
						14
01-27-2011	02-01-2041	01-27-2011	02-01-2041	250,000,000	13,625,000	15
						16
						17
05-24-2011	02-01-2041	05-24-2011	02-01-2041	100,000,000	5,450,000	18
						19
						20
06-14-2013	06-15-2043	06-14-2013	06-15-2043	400,000,000	18,400,000	21
						22
						23
06-01-2015	06-01-2065	06-01-2015	06-01-2065	500,000,000	15,512,500	24
						25
						26
						27
01-15-2013	02-01-2028	01-15-2013	02-01-2028	39,480,000	1,579,200	28
						29
						30
01-15-2013	02-01-2033	01-15-2013	02-01-2033	14,735,000	534,144	31
						32
				4,528,955,967	231,189,035	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Variable Industrial Revenue, due 2038	35,000,000	492,221
3			
4	Amortization of Interest Rate Derivative Contracts:		
5	6.625% $300 Million due 2/1/2032		
6	5.80% $200 Million due 1/15/2033		
7	6.25% $125 Million due 7/1/2036		
8	5.30% $300 Million due 5/21/2033		
9	5.25% $250 Million due 11/1/2018		
10	5.25% $100 Million due 3/1/2035		
11	6.05% $250 Million due 1/15/2038		
12	6.05% $110 Million due 1/15/2038		
13	6.05% $175 Million due 1/15/2038		
14	5.50% $150 Million due 12/15/2039		
15	5.45% $250 Million due 2/1/2041		
16	5.45% $100 Million due 2/1/2041		
17	4.35% $250 Million due 2/01/2042		
18	4.35% $250 Million due 2/01/2042		
19	4.60% $75 Million due 6/14/2043		
20	4.60% $75 Million due 6/14/2043		
21	4.60% $90 Million due 6/14/2043		
22	4.60% $80 Million due 6/14/2043		
23	4.60% $80 Million due 6/14/2043		
24	$35 Million SIFMA due 11/30/2038		
25	4.50% $300 Million due 06/01/2064		
26	5.10% $500 Million due 06/01/2065		
27	SUBTOTAL - Account 221	4,429,215,000	41,037,845
28			
29	Account 224 - Other Long Term Debt:		
30	Variable Rate Lines of Credit		
31	Contract on Natural Gas Distribution system		
32	Acquired from Charleston AFB	424,844	
33	TOTAL	4,529,541,381	43,864,328

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12-01-2008	12-01-2038	12-01-2008	12-01-2038	34,555,000	1,024,663	2
						3
						4
		01-31-2002	02-01-2032		-30,198	5
		01-23-2003	01-15-2033		-4,894	6
		06-27-2006	07-01-2036		-184,070	7
		05-21-2003	05-15-2033		304,026	8
		11-06-2003	11-01-2018		286,830	9
		03-08-2005	03-01-2035		43,699	10
		01-14-2008	01-15-2038		246,843	11
		06-24-2008	01-15-2038		-9,486	12
		03-17-2009	01-15-2038		336,119	13
		12-09-2009	12-15-2039		-405,269	14
		01-27-2011	02-01-2041		273,042	15
		05-24-2011	02-01-2041		194,342	16
		01-30-2012	02-01-2042		-246,107	17
		07-13-2012	02-01-2042		-24,396	18
		06-14-2013	06-15-2043		262,558	19
		06-14-2013	06-15-2043		263,241	20
		06-14-2013	06-15-2043		-312,928	21
		06-14-2013	06-15-2043		-280,039	22
		06-14-2013	06-15-2043		-272,735	23
		12-01-2013	11-30-2038		-176,131	24
		06-01-2014	06-01-2064		155,054	25
		06-01-2015	06-01-2065		171,606	26
				4,428,770,000	226,612,614	27
						28
						29
						30
						31
				284,430	13,536	32
				4,528,955,967	231,189,035	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Commitment Fees		
2	Nuclear Fuel Contract	99,901,537	2,826,483 D
3	SUBTOTAL - Account 224	100,326,381	2,826,483
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
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19			
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21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	4,529,541,381	43,864,328

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
					3,121,636	1
03-01-2013	11-01-2016	03-01-2013	11-01-2016	99,901,537	1,441,249	2
				100,185,967	4,576,421	3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						27
						28
						29
						30
						31
						32
				4,528,955,967	231,189,035	33

Schedule Page: 256 Line No.: 1 Column: c

With respect to unamortized amounts (premium, discount or expense) of debt redeemed, the Company follows the provisions set forth in General Instruction No. 17 of the Uniform System of Accounts. The Company records any unamortized amounts related to the redeemed debt to account 189 "Unamortized Loss on Reacquired Debt" or account 257 "Unamortized Gain on Reacquired Debt" as appropriate and amortizes this amount over the life of the new issue if refunded or over the remaining life of the original debt if not refunded.

Schedule Page: 256.2 Line No.: 30 Column: a

The Company had no long-term borrowings against its revolving credit agreements. These agreements expire in December 2018 and December 2020. See also response to Item 6 on pages 108 and 109.1.

Schedule Page: 256.2 Line No.: 32 Column: a

In 2007, the Company was awarded the contract for the privatization of the natural gas distribution system at the Charleston Air Force Base. On September 1, 2007, ownership of the system transferred to the Company and the Company recorded assets totaling $424,844 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off this long-term debt through applied billing credits over a period of 20 years. As of 12/31/2015, $284,430 was outstanding related to this obligation.

Schedule Page: 256.3 Line No.: 1 Column: i

SCANA Holding Company (parent of SCE&G) allocates interest expense on commitment fees to its operating subsidiaries. During 2015, the portion allocated to SCE&G was $219,582.

Schedule Page: 256.3 Line No.: 2 Column: a

In February 2013, SCE&G entered into a contract to acquire Enriched Uranium Product (EUP) for the initial core load of the V.C. Summer Nuclear Station Unit No. 3 currently under construction. Under the provisions of the contract, SCE&G recorded $99.9 million within Account 224 - Other Long-Term Debt and $2.8 million within Account 226 - Unamortized Discount on Long-Term Debt.

Schedule Page: 256.3 Line No.: 4 Column: i

The interest expense of $6,818,827 included in account 430 "Interest on Debt to Associated Companies" is related to short-term debt and therefore is not included in this schedule.

Schedule Page: 256.3 Line No.: 6 Column: a

The Company has authorization from the South Carolina Public Service Commission to issue up to $2.475 billion of First Mortgage Bonds(State Commission Order Nos. 2010-660 and 2013-277). As of 12/31/2015, the Company had issued 1.715 billion under such authorization.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	465,780,699
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized	180,635,896
6	Contributions in Aid of Construction	7,292,054
7	Pension Plan	9,469,300
8	Recovery of Deferred Capacity	296,001
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	261,514,639
11	Total Book Net Income Tax (including Investment Tax Credit)	222,906,286
12	Deferred Fuel Costs	90,998,200
13	Other (see detail)	83,270,400
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	38,831,918
16	Regulatory Asset - Carrying Costs	9,489,891
17	Regulatory Asset - Deferred Capacity	4,466,608
18	Other (see detail)	1,121,804
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	535,749,397
21	Repair Allowance Deduction	67,561,029
22	Domestic Production Activities Deduction	48,372,300
23	State Income Tax Deduction	29,182,500
24	Prepayment Acceleration	10,444,581
25	Deferred Nuclear Fuel Expenses	9,166,821
26	Other (see detail)	18,237,484
27	Federal Tax Net Income	549,539,142
28	Show Computation of Tax:	
29	Tax @ 35%	192,338,700
30		
31	Partnership Credits	-8,750,048
32	Adjustments for Prior Years	22,553,926
33	Current Federal income Tax Expense Recorded	206,142,578
34		
35		
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43		
44		

Schedule Page: 261 Line No.: 13 Column: b

Book Expense - Nuclear Fuel	$ 45,687,791
Regulatory Asset-Unrecovered Plant	7,913,023
Nuclear Decommissioning Expense Accrual	5,898,932
Other Post Retirement Benefits	5,366,500
Meals and Lobbying	3,622,234
Book Vehicle Depreciation Charged to Operations	3,320,310
Section 162m Limitation	2,562,361
Injuries and Damages	2,016,346
Major Maintenance Programs	1,882,390
Gas WNA Cap	1,567,619
Amortization of Losses on Reacquired Debt	1,455,207
Regulatory Asset Scrubber	1,061,940
Pollution Control	282,658
Regulatory Asset Customer Programs	272,287
VCS Costs	183,816
All Other	176,986
Total	$ 83,270,400

Schedule Page: 261 Line No.: 18 Column: b

Interest Income Amended Returns	$ 1,105,823
Unearned Revenue	15,981
Total	$ 1,121,804

Schedule Page: 261 Line No.: 26 Column: b

Long Term Disability	$ 4,411,856
Demand Side Management	4,093,800
Gas Pipeline Integrity	3,275,284
Storm Damage Accrual	1,570,008
Directors Endowment	1,109,303
Early Retirement Programs	828,924
Net Metering	704,568
Fukushima Compliance	692,746
Uncollectible Accounts	607,982
Environmental Remediation Costs	422,628
Grants	400,000
All Other	120,385
Total	$ 18,237,484

Schedule Page: 261 Line No.: 33 Column: b

South Carolina Electric & Gas Company is a wholly owned subsidiary of SCANA Corporation and is included in the consolidated federal income tax return of SCANA Corporation. Taxes are allocated to members based on their contributions to the consolidated total. Current federal income taxes recorded in 2015 by each member of the consolidated group were as follows:

SCANA Corporation	$143,700,121	
SCANA Services, Inc.	5,305,200	
South Carolina Electric & Gas Company	210,575,278	*
South Carolina Fuel Company, Inc.	(4,432,700)	*
Carolina Gas Transmission Corporation	4,161,400	
South Carolina Generating Company, Inc.	2,315,620	
Public Service Company of North Carolina	4,432,524	
PSNC Blue Ridge Corporation	367,000	
PSNC Cardinal Pipeline Corporation	872,900	
SCANA Communications, Inc.	56,719	
SCANA Communications Holding, Inc.	771,990	
SCANA Energy Marketing, Inc.	13,355,823	
Servicecare, Inc.	(10,900)	
Total	$381,470,975	

*$206,142,578

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income			206,142,578	185,673	-72,444,068
3	FUTA	9,004		228,249	232,074	-758
4	FICA	667,876		31,089,573	30,892,155	-109,357
5	Other Miscellaneous		15,978	32,696	35,693	
6	SUBTOTAL	676,880	15,978	237,493,096	31,345,595	-72,554,183
7						
8	State:					
9	Income			31,299,554	3,506,112	2,466,911
10	License			13,737,270	13,737,270	
11	Vehicle License			180,398	180,398	
12	Electric Generation	519,961		7,126,210	7,200,015	
13	SUTA	16,717		529,867	537,758	-1,609
14	Other Miscellaneous					
15	SUBTOTAL	536,678		52,873,299	25,161,553	2,465,302
16						
17	Local:					
18	County Property	156,143,116	543,088	164,949,899	157,827,990	
19	Municipal Property	8,683,695		8,611,087	8,243,360	
20	SUBTOTAL	164,826,811	543,088	173,560,986	166,071,350	
21						
22						
23						
24						
25						
26						
27						
28						
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37						
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39						
40						
41	TOTAL	166,040,369	559,066	463,927,381	222,578,498	-70,088,881

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
133,512,837		212,968,289			-6,825,711	2
4,421		86,013			142,236	3
755,937		12,380,776			18,708,797	4
	18,975				32,696	5
134,273,195	18,975	225,435,078			12,058,018	6
						7
						8
30,260,353		31,801,445			-501,891	9
		13,615,477			121,793	10
					180,398	11
446,156		7,260,265			-134,055	12
7,217		182,145			347,722	13
						14
30,713,726		52,859,332			13,967	15
						16
						17
163,330,465	608,528	144,743,339			20,206,560	18
9,051,422		7,572,597			1,038,490	19
172,381,887	608,528	152,315,936			21,245,050	20
						21
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337,368,808	627,503	430,610,346			33,317,035	41

Schedule Page: 262 Line No.: 2 Column: f

Prior Year overpayment of taxes reclassified from account 143-Other Accounts Receivable	($76,244,168)
Reclassified Amount from account 283 - Accumulated Deferred Income Taxes	3,800,100
Total	($72,444,068)

Schedule Page: 262 Line No.: 3 Column: f

Estimated payroll taxes in the amount of ($2,309,505) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2015. Those adjustments are combined with a total of $2,197,781 of payroll taxes related to at-risk incentive compensation actually paid in 2015 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($111,724).

Schedule Page: 262 Line No.: 4 Column: f

Estimated payroll taxes in the amount of ($2,309,505) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2015. Those adjustments are combined with a total of $2,197,781 of payroll taxes related to at-risk incentive compensation actually paid in 2015 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($111,724).

Schedule Page: 262 Line No.: 9 Column: f

Prior Year overpayment of taxes reclassified from account 143-Other Accounts Receivable	($ 6,480,189)
Reclassified Amount from account 283 - Accumulated Deferred Income Taxes	8,947,100
Total	$ 2,466,911

Schedule Page: 262 Line No.: 13 Column: f

Estimated payroll taxes in the amount of ($2,309,505) related to at-risk incentive compensation and carryover paid time off accruals were recorded to Accounts 242/253 and expensed in 2015. Those adjustments are combined with a total of $2,197,781 of payroll taxes related to at-risk incentive compensation actually paid in 2015 with no impact on Account 236, to arrive at the total of the combined adjustment amount in lines 3, 4 and 13 of ($111,724).

Schedule Page: 262 Line No.: 22 Column: a

Taxes related to the Company's common utility operations are apportioned to electric and gas operations based on functional usage of common property, revenue or payroll as applicable.

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	278,642			411.4	46,530	
4	7%						
5	10%	17,265,546			411.4	910,900	
6	8%	5,698,338			411.4	324,070	
7	20%	52,874			411.4	4,200	
8	TOTAL	23,295,400				1,285,700	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility						
11	4%	30,594			411.4	5,060	
12	10%	697,218			411.4	52,403	
13	20%	14,198			411.4	906	
14	8%	941,390			411.4	54,231	
15	See Footnote	972,800			411.4	972,800	
16	Total Gas	2,656,200				1,085,400	
17							
18							
19							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
232,112	58.4 Years		3
			4
16,354,646	58.4 Years		5
5,374,268	58.4 Years		6
48,674	58.4 Years		7
22,009,700			8
			9
			10
25,534	47.5 Years		11
644,815	47.5 Years		12
13,292	47.5 Years		13
887,159	47.5 Years		14
	See Footnote		15
1,570,800			16
			17
			18
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			48

Schedule Page: 266 Line No.: 15 Column: h

State of South Carolina Economic Impact Zone Investment Tax Credit.

Effective November 2010, pursuant to authorization by the South Carolina Public Service Commission, the Company accelerated the amortization of these Investment Tax Credits over a five year period.

Schedule Page: 266 Line No.: 15 Column: i

State of South Carolina Economic Impact Zone Investment Tax Credit.

Effective November 2010, pursuant to authorization by the South Carolina Public Service Commission, the Company accelerated the amortization of these Investment Tax Credits over a five year period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accrued Pension Liability - Early					
2	Retirement Incentive Programs &					
3	Other	11,535,183	Various	1,269,383	440,459	10,706,259
4	Accrued Liability - Incentive Plan	4,392,829	Various	16,550,859	16,624,561	4,466,531
5	Gas Environmental Remediation	19,326,542	182	96,159,009	95,376,966	18,544,499
6	Other Environmental Remediation	1,165,211	Various	3,905,348	3,349,337	609,200
7	Long-Term Disability	6,140,209	131	5,354,182	942,326	1,728,353
8	Accrued Liability - Director's					
9	Endowment Program	4,294,249	131/426.5	1,358,078	190,123	3,126,294
10	Life Insurance Premium Obligation	11,714	926	11,856	6,138	5,996
11	Santee River Basin Accord	1,251,123	131	133,348	28,130	1,145,905
12	Municipal Nonstandard Service Fund					
13	Matching Obligation	5,941,666	186	933,956		5,007,710
14	SRS Substation	1,997,887	456	96,284		1,901,603
15	Interconnection Study Deposits	215,600	234/456	1,245,902	1,565,753	535,451
16	New Nuclear Transmission Lines	180,000	131	90,000		90,000
17	CIAC Obligations	16,089,000	118	168,110	1,993,980	17,914,870
18	Noncontrolling Interest - SCFC	2,278,058			418,168	2,696,226
19	Other	654,546	Various	4,381,232	4,503,612	776,926
20						
21						
22						
23						
24						
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45						
46						
47	TOTAL	75,473,817		131,657,547	125,439,553	69,255,823

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	10,509,025	1,852,275	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	10,509,025	1,852,275	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	10,509,025	1,852,275	
18	Classification of TOTAL			
19	Federal Income Tax	9,135,300	1,610,100	
20	State Income Tax	1,373,725	242,175	
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						12,361,300	4
							5
							6
							7
						12,361,300	8
							9
							10
							11
							12
							13
							14
							15
							16
						12,361,300	17
							18
						10,745,400	19
						1,615,900	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,367,901,815	194,060,916	191,442,075
3	Gas	141,264,800	14,845,200	2,827,100
4	Other - Non Operating	8,840,600		
5	TOTAL (Enter Total of lines 2 thru 4)	1,518,007,215	208,906,116	194,269,175
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,518,007,215	208,906,116	194,269,175
10	Classification of TOTAL			
11	Federal Income Tax	1,348,921,005	184,654,016	169,543,200
12	State Income Tax	169,086,210	24,252,100	24,725,975
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3	16,033,058	182.3	16,351,610	1,370,839,208	2
		182.3	1,023,800	182.3	1,026,100	153,285,200	3
9,300	39,200					8,810,700	4
9,300	39,200		17,056,858		17,377,710	1,532,935,108	5
							6
							7
							8
9,300	39,200		17,056,858		17,377,710	1,532,935,108	9
							10
1,500	34,000		14,852,108		15,202,878	1,364,350,091	11
7,800	5,200		2,204,750		2,174,832	168,585,017	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Asset Retirement Obligation	103,291,100	12,303,800	339,800
4	Employee Benefit Plan Costs	79,650,900	1,788,600	8,414,200
5	Unrecovered Plant Canadys	52,273,200	100	3,026,900
6	Prepayments	21,565,700	3,264,900	
7	Demand Side Management Costs	21,205,600	1,746,000	
8	All Other	40,671,700	5,765,400	43,264,700
9	TOTAL Electric (Total of lines 3 thru 8)	318,658,200	24,868,800	55,045,600
10	Gas			
11	Employee Benefit Plan Costs	11,404,800	931,300	1,015,700
12	Asset Retirement Obligation	6,102,800	363,700	
13	Prepayments	3,405,600	791,200	61,200
14	Deferred Fuel Costs	2,199,800	4,964,200	4,479,100
15	Gas Pipeline Integrity		1,424,300	
16	All Other	2,403,100	435,600	3,156,600
17	TOTAL Gas (Total of lines 11 thru 16)	25,516,100	8,910,300	8,712,600
18	Non Operating	58,304,990		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	402,479,290	33,779,100	63,758,200
20	Classification of TOTAL			
21	Federal Income Tax	342,586,720	29,362,600	55,423,000
22	State Income Tax	59,892,570	4,416,500	8,335,200
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						115,255,100	3
						73,025,300	4
						49,246,400	5
						24,830,600	6
						22,951,600	7
		236	12,747,200			-9,574,800	8
			12,747,200			275,734,200	9
							10
						11,320,400	11
						6,466,500	12
						4,135,600	13
						2,684,900	14
						1,424,300	15
						-317,900	16
						25,713,800	17
6,259,000	817,300			219	23,110	63,769,800	18
6,259,000	817,300		12,747,200		23,110	365,217,800	19
							20
5,440,700	710,400		3,800,100		20,080	317,476,600	21
818,300	106,900		8,947,100		3,030	47,741,200	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Pension Plan	($11,506,300)	$ 3,096,500	$ 6,295,800		($14,705,600)
Deferred Fuel Costs	25,152,600	175,200	35,467,100		(10,139,300)
Reacquired Debt	6,011,300	77,800	556,700		5,532,400
Regulatory Asset-					
Deferred Capacity	2,435,800	1,709,500	-		4,145,300
VCS Costs	1,934,600	-	70,300		1,864,300
Fukushima Compliance	1,168,000	264,900	20,500		1,412,400
Grants	1,390,500	153,000	702,000		841,500
Recovery of Deferred Capacity	627,400	800	114,000		514,200
FIN 48 Reserve	12,747,200	-	-	($12,747,200)	-
All Other	710,600	287,700	38,300		960,000
Total	$40,671,700	$ 5,765,400	$43,264,700	($12,747,200)	($ 9,574,800)

Schedule Page: 276 Line No.: 8 Column: h

FIN 48 Reserve amount reclassified to Account 236 - Taxes Accrued.

Schedule Page: 276 Line No.: 16 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Balance at End of Year
Pension Plan	$ 687,400	$ 435,600	$ 2,330,100	($ 1,207,100)
Reacquired Debt	753,800	-	77,300	676,500
Regulatory Asset-				
Customer Programs	326,000	-	113,300	212,700
Gas WNA Cap	635,900	-	635,900	-
Total	$ 2,403,100	$ 435,600	$ 3,156,600	($ 317,900)

Schedule Page: 276 Line No.: 18 Column: a

	Balance at Beg. of Year	Amt. Debited Acct. 410.2	Amt. Credited Acct.411.2	Adjust.	Balance at End of Year
Pension Plan	$50,645,590	$ -	$ 371,600	$ 23,110	$50,297,100
Regulatory Asset-					
Carrying Costs	3,343,900	3,630,100	-		6,974,000
Partnership Credits	3,869,800	2,205,900	-		6,075,700
All Other	445,700	423,000	445,700		423,000
Total	$58,304,990	$ 6,259,000	$ 817,300	$ 23,110	$63,769,800

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Accumulated Deferred Income Tax Credits	15,523,899	190	1,028,800	111,501	14,606,600
2	Storm Damage Reserve	5,470,823	571/593	1,931,183	361,175	3,900,815
3	Nuclear Refueling Accrual	5,263,097	524/528	32,076,275	26,813,178	
4	NOX Emission Allowance Proceeds	153,296			569	153,865
5	Interest Rate Derivatives (3/2009-6/2043)	87,327,723	176/427/421	52,487,187	61,270,846	96,111,382
6	Demand Side Management Carrying Costs	5,791,811	182.3	1,415,753	1,575,995	5,952,053
7	SO2 Emission Allowance Proceeds	438			433	871
8	Overcollected Electric Pension Expense	173,247	926	173,247		
9	Wholesale Fuel Overcollection		447	215,254	1,293,088	1,077,834
10	Major Maintenance Accrual and Interest		Various	3,470,785	3,470,785	
11	Amt. Overcollected - Elec Fuel Adjustment Clause		449/173	38,817,903	64,249,679	25,431,776
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	119,704,334		131,616,387	159,147,249	147,235,196

Schedule Page: 278 Line No.: 2 Column: a

SCPSC Docket No. 95-1000-E
SCPSC Docket No. 2007-335-E
SCPSC Docket No. 2008-416-E
SCPSC Docket No. 2009-489-E
SCPSC Docket NO. 2012-218-E

Schedule Page: 278 Line No.: 3 Column: a

SCPSC Docket No. 2012-218-E

Schedule Page: 278 Line No.: 5 Column: a

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

In SCPSC Docket No. 2014-44-E, the SCPSC authorized the Company to utilize a portion of deferred swap settlement gains to offset certain Net Lost Revenue amounts associated with the Company's Demand Side Management Programs. Such utilization is also included in current year account activity.

Schedule Page: 278 Line No.: 6 Column: a

SCPSC Docket No. 2013-50-E
SCPSC Docket No. 2013-208-E
SCPSC Docket No. 2014-44-E
SCPSC Docket No. 2015-45-E

Schedule Page: 278 Line No.: 8 Column: a

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2014-88-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

Schedule Page: 278 Line No.: 10 Column: a

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

Schedule Page: 278 Line No.: 11 Column: a

SCPSC Docket No. 2015-2-E

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,144,628,202	1,163,092,091
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	829,184,845	838,612,663
5	Large (or Ind.) (See Instr. 4)	427,958,743	464,102,667
6	(444) Public Street and Highway Lighting	14,364,720	14,131,899
7	(445) Other Sales to Public Authorities	47,280,395	49,418,059
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,463,416,905	2,529,357,379
11	(447) Sales for Resale	49,093,118	56,724,721
12	TOTAL Sales of Electricity	2,512,510,023	2,586,082,100
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,512,510,023	2,586,082,100
15	Other Operating Revenues		
16	(450) Forfeited Discounts	7,199,589	6,838,882
17	(451) Miscellaneous Service Revenues	3,698,815	3,802,376
18	(453) Sales of Water and Water Power	431,911	459,046
19	(454) Rent from Electric Property	20,040,653	18,074,094
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	5,165,454	5,970,713
22	(456.1) Revenues from Transmission of Electricity of Others	8,058,377	7,990,918
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	44,594,799	43,136,029
27	TOTAL Electric Operating Revenues	2,557,104,822	2,629,218,129

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,977,834	8,155,692	596,686	587,870	2
				3
7,398,918	7,385,143	93,178	91,954	4
6,201,242	6,233,593	757	753	5
73,740	71,710	1,022	708	6
520,849	528,377	3,191	3,386	7
				8
				9
22,172,583	22,374,515	694,834	684,671	10
942,262	958,427	4	5	11
23,114,845	23,332,942	694,838	684,676	12
				13
23,114,845	23,332,942	694,838	684,676	14

Line 12, column (b) includes $ 82,040,468 of unbilled revenues.

Line 12, column (d) includes 630,386 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 5 Column: d

Includes 3,267 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 5 Column: e

Includes 3,337 MWH supplied to a single large industrial customer from a Company owned solar generation facility located on the rooftop of the customer's premise. The corresponding revenue is billed via a monthly facilities fee and is recorded in Account 454, Rent From Electric Property.

Schedule Page: 300 Line No.: 10 Column: b

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($31,953,022)
Commercial	(30,007,949)
Industrial	(25,682,833)
Street Lighting	(309,214)
Other Public Authorities	(2,133,595)
	($90,086,613)

Includes Unmetered Sales Revenue as follows:

Residential	$19,257,846
Commercial/Industrial	29,633,344
Street Lighting	13,520,908
Other Public Authorities	145,036
	$62,557,134

Schedule Page: 300 Line No.: 10 Column: c

Includes the following amounts under-collected pursuant to the respondent's fuel adjustment clause:

Residential	$ 971,774
Commercial	871,478
Industrial	931,042
Street Lighting	10,716
Other Public Authorities	64,637
	$2,849,647

Includes Unmetered Sales Revenue as follows:

Residential	$19,328,022
Commercial/Industrial	29,511,187
Street Lighting	12,993,793
Other Public Authorities	145,562
	$61,978,564

Schedule Page: 300 Line No.: 10 Column: d

Includes Unmetered MWH Sales as follows:

Residential	80,027
Commercial/Industrial	148,709
Street Lighting	66,053
Other Public Authorities	1,038
	295,827

Schedule Page: 300 Line No.: 10 Column: e

Includes Unmetered MWH Sales as follows:

Residential	78,931
Commercial/Industrial	136,855
Street Lighting	64,062
Other Public Authorities	1,066
	280,914

Schedule Page: 300 Line No.: 10 Column: f

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	209,733
Commercial/Industrial	24,858
Street Lighting	972
Other Public Authorities	59
	235,622

Schedule Page: 300 Line No.: 10 Column: g

Excludes Unmetered Average No. Customers Per Month as follows:

Residential	214,333
Commercial/Industrial	25,417
Street Lighting	879
Other Public Authorities	56
	240,685

Schedule Page: 300 Line No.: 17 Column: b

Includes $1,317,527 of reconnect and lighting disconnect charges.

Includes $2,254,755 of transmission maintenance fee revenue.

Includes $450,753 of returned check fees.

Account balance also includes debit activity of ($487,963) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 17 Column: c

Includes $1,537,221 of reconnect and lighting disconnect charges.

Includes $2,024,507 of transmission maintenance fee revenue.

Includes $499,062 of returned check fees.

Account balance also includes debit activity of ($402,446) associated with temporary facilities in accordance with the Uniform System of Accounts instructions.

Schedule Page: 300 Line No.: 21 Column: b

Includes $4,362,458 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $401,419 of rental income.

Schedule Page: 300 Line No.: 21 Column: c

Includes $5,202,931 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $373,484 for sale of used oil.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales					
2	RATE					
3	1	334,659	45,765,490	21,370	15,660	0.1368
4	2	24,292	4,283,299	15,500	1,567	0.1763
5	5	1,136	160,471	76	14,947	0.1413
6	6	476,044	65,211,204	31,194	15,261	0.1370
7	7	333	38,448	9	37,000	0.1155
8	8	7,057,216	1,009,889,716	528,191	13,361	0.1431
9	E1N	23	3,191	2	11,500	0.1387
10	E6N	21	3,129	3	7,000	0.1490
11	E8N	189	28,158	24	7,875	0.1490
12	M1N	430	58,937	25	17,200	0.1371
13	M2N	1	152			0.1520
14	M5N	7	1,000	1	7,000	0.1429
15	M6N	649	90,050	52	12,481	0.1388
16	M8N	3,150	451,880	239	13,180	0.1435
17	Special (A)	79,684	18,643,077	209,733	380	0.2340
18	Total Residential	7,977,834	1,144,628,202	806,419	9,893	0.1435
19						
20	Commercial & Industrial Sales					
21	RATE					
22	3	12,125	1,380,690	245	49,490	0.1139
23	9	2,615,669	346,810,942	78,121	33,482	0.1326
24	10	4,314	795,609	2,126	2,029	0.1844
25	11	15,233	1,620,439	312	48,824	0.1064
26	12	161,614	18,171,932	3,700	43,679	0.1124
27	14	20,479	2,930,401	1,860	11,010	0.1431
28	16	46,141	5,944,553	2,787	16,556	0.1288
29	20	1,877,495	196,025,385	2,142	876,515	0.1044
30	21	362,353	34,782,809	539	672,269	0.0960
31	22	416,008	48,999,984	1,764	235,832	0.1178
32	23	4,074,888	302,749,168	124	32,862,000	0.0743
33	24	2,019,307	171,862,865	183	11,034,464	0.0851
34	27	842,702	56,436,855	8	105,337,750	0.0670
35	28	2,563	308,146	20	128,150	0.1202
36	60	981,193	40,550,977	4	245,298,250	0.0413
37	E9N	44	5,992	2	22,000	0.1362
38	Special (A)	148,032	27,766,841	24,301	6,092	0.1876
39	Total Commercial & Industrial	13,600,160	1,257,143,588	118,238	115,024	0.0924
40						
41	TOTAL Billed	21,542,197	2,381,396,437	0	0	0.1105
42	Total Unbilled Rev.(See Instr. 6)	630,386	82,020,468	0	0	0.1301
43	TOTAL	22,172,583	2,463,416,905	0	0	0.1111

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Public Street & Highway					
2	Lighting Sales					
3	RATE					
4	3	1,727	217,082	98	17,622	0.1257
5	9	2,464	452,984	547	4,505	0.1838
6	13	3,821	490,810	377	10,135	0.1285
7	Special (A)	65,728	13,203,844	960	68,467	0.2009
8	Total Public Street & Hwy Lights	73,740	14,364,720	1,982	37,205	0.1948
9						
10	Other Sales to Public Authorities					
11	RATE					
12	3	146,831	16,642,629	2,979	49,289	0.1133
13	9	1,510	216,098	146	10,342	0.1431
14	20	12,735	1,193,593	8	1,591,875	0.0937
15	21	2,939	278,759	3	979,667	0.0948
16	65	67,940	5,243,791	21	3,235,238	0.0772
17	66	288,623	23,665,664	35	8,246,371	0.0820
18	Special (A)	271	39,861	11	24,636	0.1471
19	Total OPAs	520,849	47,280,395	3,203	162,613	0.0908
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30	Special (A) is included in					
31	respondent's other					
32	published tariffs and counted					
33	on these lines per Instruction 3					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	21,542,197	2,381,396,437	0	0	0.1105
42	Total Unbilled Rev.(See Instr. 6)	630,386	82,020,468	0	0	0.1301
43	TOTAL	22,172,583	2,463,416,905	0	0	0.1111

Schedule Page: 304 Line No.: 18 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($31,953,022)
Commercial	(30,007,949)
Industrial	(25,682,833)
Street Lighting	(309,214)
Other Public Authorities	(2,133,595)
	($90,086,613)

Schedule Page: 304 Line No.: 39 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($31,953,022)
Commercial	(30,007,949)
Industrial	(25,682,833)
Street Lighting	(309,214)
Other Public Authorities	(2,133,595)
	($90,086,613)

Schedule Page: 304.1 Line No.: 8 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($31,953,022)
Commercial	(30,007,949)
Industrial	(25,682,833)
Street Lighting	(309,214)
Other Public Authorities	(2,133,595)
	($90,086,613)

Schedule Page: 304.1 Line No.: 19 Column: c

Includes the following amounts over-collected pursuant to the respondent's fuel adjustment clause:

Residential	($31,953,022)
Commercial	(30,007,949)
Industrial	(25,682,833)
Street Lighting	(309,214)
Other Public Authorities	(2,133,595)
	($90,086,613)

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Town of McCormick	RQ		3.7	3.8	3.8
2	City of Orangeburg	RQ		138.2	146.5	141.6
3	Town of Winnsboro	RQ		11.6	12.2	12.4
4	Cargill Power Markets, LLC	OS				
5	Duke Energy Carolinas, LLC	OS				
6	North Carolina Electric Membership					
7	Corporation	OS				
8	The Energy Authority, Inc.	OS				
9	South Carolina Public Service Authority	OS				
10	Multiple Counterparties	AD				
11	Emissions Allow Sales - Revenue Contra					
12	Wholesale Fuel Over/Under Collection					
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
20,066	544,527	678,133	-2,523	1,220,137	1
850,648	12,121,769	33,966,107		46,087,876	2
66,401	1,108,710	2,423,806	397,277	3,929,793	3
50		2,350		2,350	4
1,100		159,050		159,050	5
					6
1,080		40,500		40,500	7
2,400		131,600		131,600	8
517		114,199		114,199	9
			-242,033	-242,033	10
			-877	-877	11
			-2,349,477	-2,349,477	12
					13
					14
937,115	13,775,006	37,068,046	394,754	51,237,806	
5,147	0	447,699	-2,592,387	-2,144,688	
942,262	**13,775,006**	**37,515,745**	**-2,197,633**	**49,093,118**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Transmission Revenue included in					
2	Energy Charges Column (i).					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
937,115	13,775,006	37,068,046	394,754	51,237,806	
5,147	0	447,699	-2,592,387	-2,144,688	
942,262	**13,775,006**	**37,515,745**	**-2,197,633**	**49,093,118**	

Schedule Page: 310 Line No.: 1 Column: c
FERC Electric Tariff, Fourth Revised Volume No. 1

Schedule Page: 310 Line No.: 1 Column: j
Wholesale Refund for 2015.

Schedule Page: 310 Line No.: 2 Column: c
FERC Electric Rate Schedule No. 60

Schedule Page: 310 Line No.: 3 Column: c
FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 3 Column: j
Network transmission and ancillary services charges for the Town of Winnsboro. The transmission reservation is held by SCE&G Power Marketing which is serving as the agent for the Town of Winnsboro. Transmission base revenue totals $362,461 and ancillary services revenue totals $47,713.

Transmission refund of ($4,514) related to prior period billing correction is shown as a credit on the February 2015 bill.

Wholesale refund for 2015 is ($8,383).

Schedule Page: 310 Line No.: 4 Column: b
OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 4 Column: c
FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 5 Column: b
OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 5 Column: c
FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 7 Column: b
OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 7 Column: c
FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 8 Column: b
OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 8 Column: c
FERC Electric Tariff, Seventh Revised Volume No. 2

Schedule Page: 310 Line No.: 9 Column: b
OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

Schedule Page: 310 Line No.: 9 Column: c
FERC Electric Rate Schedule No. 33

Schedule Page: 310 Line No.: 10 Column: b
AD - Multiple Counterparties.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 10 Column: j

Wholesale Refunds for 2008-2014:

McCormick	($ 11,424)
Winnsboro	(35,890)
Orangeburg	(139,686)
CEPC	(34,345)
Greenwood	(20,688)
Total	($242,033)

Schedule Page: 310 Line No.: 11 Column: j

Transfer of gain / loss on sale of emission allowances to Account 254 - Other Regulatory Liabilities for purchasing future emission allowances.

Schedule Page: 310 Line No.: 12 Column: j

Over/under collection of fuel relating to sales to wholesale customers.

Schedule Page: 310.1 Line No.: 2 Column: i

Subtotal non-RQ of $447,699 includes transmission revenue for OS service of $54,209. Transmission base revenue totals $51,018 and ancillary services revenue totals $3,191.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,419,201	2,161,090
5	(501) Fuel	280,051,019	354,576,791
6	(502) Steam Expenses	13,218,658	16,116,564
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,537,786	5,374,910
10	(506) Miscellaneous Steam Power Expenses	6,232,820	5,610,284
11	(507) Rents	1,500	9,977
12	(509) Allowances	19,389	280,940
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	307,480,373	384,130,556
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	85,716	79,209
16	(511) Maintenance of Structures	1,862,262	1,160,209
17	(512) Maintenance of Boiler Plant	12,896,627	13,050,710
18	(513) Maintenance of Electric Plant	12,615,664	11,863,967
19	(514) Maintenance of Miscellaneous Steam Plant	6,265,718	4,724,110
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	33,725,987	30,878,205
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	341,206,360	415,008,761
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	9,399,979	9,291,240
25	(518) Fuel	45,687,791	46,626,853
26	(519) Coolants and Water	3,149,217	2,790,759
27	(520) Steam Expenses	7,326,705	8,079,790
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,359,644	2,759,022
31	(524) Miscellaneous Nuclear Power Expenses	37,477,684	37,745,367
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	105,401,020	107,293,031
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-3,055,152	-6,444,574
36	(529) Maintenance of Structures	3,106,875	3,944,397
37	(530) Maintenance of Reactor Plant Equipment	14,474,420	17,174,412
38	(531) Maintenance of Electric Plant	3,416,419	3,572,623
39	(532) Maintenance of Miscellaneous Nuclear Plant	17,185,353	17,763,933
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	35,127,915	36,010,791
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	140,528,935	143,303,822
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	770,952	790,193
45	(536) Water for Power		
46	(537) Hydraulic Expenses	1,398,001	1,380,176
47	(538) Electric Expenses	162,263	178,574
48	(539) Miscellaneous Hydraulic Power Generation Expenses	726,151	656,211
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	3,057,367	3,005,154
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	145,819	136,004
54	(542) Maintenance of Structures	7,785	162,777
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,034,426	905,926
56	(544) Maintenance of Electric Plant	3,441,143	2,520,808
57	(545) Maintenance of Miscellaneous Hydraulic Plant	76,450	129,992
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,705,623	3,855,507
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	7,762,990	6,860,661

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,146,657	1,041,855
63	(547) Fuel	185,680,047	247,487,163
64	(548) Generation Expenses	4,757,331	4,298,392
65	(549) Miscellaneous Other Power Generation Expenses	1,617,315	1,943,589
66	(550) Rents	43,752	2,473
67	TOTAL Operation (Enter Total of lines 62 thru 66)	193,245,102	254,773,472
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	469,644	468,415
70	(552) Maintenance of Structures	584,816	542,199
71	(553) Maintenance of Generating and Electric Plant	11,824,623	11,977,720
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	654,807	749,383
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	13,533,890	13,737,717
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	206,778,992	268,511,189
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	282,221,548	311,058,580
77	(556) System Control and Load Dispatching	2,937,877	2,201,882
78	(557) Other Expenses	267,004	382,158
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	285,426,429	313,642,620
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	981,703,706	1,147,327,053
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	851,568	905,055
84			
85	(561.1) Load Dispatch-Reliability	1,038,723	1,264,086
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	599,016	876,821
87	(561.3) Load Dispatch-Transmission Service and Scheduling	186,478	211,643
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	48,676	99,185
90	(561.6) Transmission Service Studies	8,136	-244
91	(561.7) Generation Interconnection Studies	-191,571	19,809
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	452,676	395,129
94	(563) Overhead Lines Expenses	365,391	380,296
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	2,700,581	3,177,500
97	(566) Miscellaneous Transmission Expenses	3,137,388	4,779,166
98	(567) Rents	329,966	320,129
99	TOTAL Operation (Enter Total of lines 83 thru 98)	9,527,028	12,428,575
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	23,243	27,017
102	(569) Maintenance of Structures	15,526	21,837
103	(569.1) Maintenance of Computer Hardware		685
104	(569.2) Maintenance of Computer Software	7,755	276,143
105	(569.3) Maintenance of Communication Equipment	34,319	19,423
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,807,075	3,005,563
108	(571) Maintenance of Overhead Lines	5,213,367	5,801,524
109	(572) Maintenance of Underground Lines	99,900	5,497
110	(573) Maintenance of Miscellaneous Transmission Plant	255,156	120,449
111	TOTAL Maintenance (Total of lines 101 thru 110)	8,456,341	9,278,138
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	17,983,369	21,706,713

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	866,816	872,900
135	(581) Load Dispatching	967,713	853,315
136	(582) Station Expenses	605,692	605,612
137	(583) Overhead Line Expenses	1,392,041	1,135,897
138	(584) Underground Line Expenses	236,491	239,055
139	(585) Street Lighting and Signal System Expenses	337,282	364,433
140	(586) Meter Expenses	1,512,216	1,203,304
141	(587) Customer Installations Expenses	15,547	10,056
142	(588) Miscellaneous Expenses	7,452,109	7,186,569
143	(589) Rents	2,305,730	2,194,151
144	TOTAL Operation (Enter Total of lines 134 thru 143)	15,691,637	14,665,292
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	301,837	335,207
147	(591) Maintenance of Structures	10,205	10,711
148	(592) Maintenance of Station Equipment	3,663,286	4,062,082
149	(593) Maintenance of Overhead Lines	27,623,945	23,352,456
150	(594) Maintenance of Underground Lines	2,774,804	2,913,368
151	(595) Maintenance of Line Transformers	167,226	264,794
152	(596) Maintenance of Street Lighting and Signal Systems	2,715,852	2,625,330
153	(597) Maintenance of Meters	302,672	222,295
154	(598) Maintenance of Miscellaneous Distribution Plant	2,886,479	3,017,972
155	TOTAL Maintenance (Total of lines 146 thru 154)	40,446,306	36,804,215
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	56,137,943	51,469,507
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,699,047	1,503,947
160	(902) Meter Reading Expenses	1,772,854	1,616,362
161	(903) Customer Records and Collection Expenses	36,529,324	36,424,169
162	(904) Uncollectible Accounts	5,697,561	7,009,696
163	(905) Miscellaneous Customer Accounts Expenses	2,295,274	2,246,450
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	47,994,060	48,800,624

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	319,698	330,730
168	(908) Customer Assistance Expenses	12,828,632	8,973,332
169	(909) Informational and Instructional Expenses		1,960
170	(910) Miscellaneous Customer Service and Informational Expenses	281,313	272,209
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	13,429,643	9,578,231
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		1,083
175	(912) Demonstrating and Selling Expenses	1,504,308	1,443,258
176	(913) Advertising Expenses	-3,158	-23
177	(916) Miscellaneous Sales Expenses	253,830	192,080
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,754,980	1,636,398
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	56,641,077	55,094,303
182	(921) Office Supplies and Expenses	17,782,876	19,847,487
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	15,282,833	13,867,035
185	(924) Property Insurance	6,719,399	7,063,100
186	(925) Injuries and Damages	6,982,006	5,858,213
187	(926) Employee Pensions and Benefits	39,648,705	44,906,622
188	(927) Franchise Requirements	8,569	7,641
189	(928) Regulatory Commission Expenses	5,324,591	5,051,779
190	(929) (Less) Duplicate Charges-Cr.	8,786,659	9,365,973
191	(930.1) General Advertising Expenses	157	39,790
192	(930.2) Miscellaneous General Expenses	16,226,454	16,485,465
193	(931) Rents	4,779,376	4,117,652
194	TOTAL Operation (Enter Total of lines 181 thru 193)	160,609,384	162,973,114
195	Maintenance		
196	(935) Maintenance of General Plant	6,334,105	6,442,313
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	166,943,489	169,415,427
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,285,947,190	1,449,933,953

Schedule Page: 320 Line No.: 35 Column: b

In SCPSC Docket No. 2012-218-E, the SCPSC authorized the Company to establish a 5-cycle or 90 month recovery of nuclear outage costs for V.C. Summer Nuclear Station Unit 1. Accordingly, the Company is accruing $17.2 million annually with $13.9 million and $3.3 million being accrued to account 528 and 524, respectively. Differences between actual outage costs incurred and the accrued amounts are recognized as regulatory assets or liabilities as appropriate. During 2015, the Company reversed actual outage costs of $20.6 million from account 528 and applied such costs against the established regulatory liability. As a result, the Company has reported net credit activity for the year in account 528.

Schedule Page: 320 Line No.: 35 Column: c

In SCPSC Docket No. 2012-218-E, the SCPSC authorized the Company to establish a 5-cycle or 90 month recovery of nuclear outage costs for V.C. Summer Nuclear Station Unit 1. Accordingly, the Company is accruing $17.2 million annually with $13.9 million and $3.3 million being accrued to account 528 and 524, respectively. Differences between actual outage costs incurred and the accrued amounts are recognized as regulatory assets or liabilities as appropriate. During 2014, the Company reversed actual outage costs of $23.9 million from account 528 and applied such costs against the established regulatory liability. As a result, the Company has reported net credit activity for the year in account 528.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Georgia Power	RQ	Schedule #793			
2	Mid-Carolina Electric Coop	RQ	5/8/2015			
3	Newberry Electric Cooperative	RQ	10/3/1975,5/3/1976			
4	Santee Cooper	RQ	1/7/1997			
5	Santee Cooper	RQ	7/29/1996			
6	Columbia Energy LLC	OS	Tariff #1			
7	International Paper	OS	5/1/1984			
8	Misc Territorial Customers	OS	Rate-PR1			
9	City of Columbia - Columbia Hydro	RQ	2/2002			
10	Southeastern Power Administration	RQ	1/2001,12/2002			
11	South Carolina Generating Company, Inc	RQ	Schedule #1		601	579
12	Cargill Power Markets, LLC	OS	Schedule #1			
13	Duke Energy Carolinas, LLC	OS	Tariff #5			
14	Exelon Generation Company, LLC	OS	Tariff #3			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
517				14,270		14,270	1
8				1,108		1,108	2
75				14,067		14,067	3
20,259				811,684		811,684	4
1,151				114,694		114,694	5
6,006				252,066		252,066	6
3,321				149,509		149,509	7
750				53,599		53,599	8
23,727				1,523,077		1,523,077	9
49					69,573	69,573	10
3,734,928				229,240,826		229,240,826	11
48,592				1,699,505		1,699,505	12
15,825				839,913		839,913	13
40,556				1,195,442		1,195,442	14
4,954,820	211	2,791	16,647,554	265,834,725	-260,731	282,221,548	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	North Carolina Municipal Power					
2	Agency No. 1	OS	6/1/2003			
3	PJM Settlement, Inc.	OS	Tariff #1			
4	Rainbow Energy Marketing Corporation	OS	Tariff #1			
5	Southern Company Services, Inc.	OS	Tariff #4			
6	The Energy Authority, Inc	OS	12/1/2004			
7	Duke Energy Progress, Inc.	OS				
8	Duke Energy Carolinas, LLC	OS				
9	South Carolina Public Service					
10	Authority	OS				
11	TIG Sun Energy III, LLC	OS				
12	Columbia Energy LLC	IU	Tariff #1			
13	Southern Company Services, Inc.	IF	Tariff #4			
14	Santee Cooper	LF	1/7/1997	25		
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
13,600				372,000		372,000	2
550				14,481		14,481	3
5,403				1,939,375		1,939,375	4
27,779			87,200	1,014,452		1,101,652	5
6,858				246,696		246,696	6
1,011				42,898		42,898	7
1,880				79,889		79,889	8
							9
258				12,821		12,821	10
22				1,513		1,513	11
732,485			9,405,000	18,639,533	336,900	28,381,433	12
233,161			3,539,904	6,862,522		10,402,426	13
36,049			3,615,450	1,507,891		5,123,341	14
4,954,820	211	2,791	16,647,554	265,834,725	-260,731	282,221,548	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Columbia Energy LLC	EX	Tariff #5			
2	Adjustments					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	211	2,791		-809,106		-809,106	1
					-667,204	-667,204	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,954,820	211	2,791	16,647,554	265,834,725	-260,731	282,221,548	

Schedule Page: 326 Line No.: 1 Column: c

Contract for electric service dated 6/20/1973.

Schedule Page: 326 Line No.: 2 Column: c

Contract for electric service dated 5/8/2015.

Schedule Page: 326 Line No.: 3 Column: c

Contracts for electric service dated 10/3/1975 and 5/3/1976.

Schedule Page: 326 Line No.: 4 Column: c

Contract for electric service dated 1/7/1997.

Schedule Page: 326 Line No.: 5 Column: c

Contract for electric service dated 7/29/1996.

Schedule Page: 326 Line No.: 6 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 6 Column: c

Contract for Test and Excess Energy Purchase and Sale Agreement between South Carolina Electric & Gas Company and Columbia Energy LLC dated as of 1/17/2004.

Schedule Page: 326 Line No.: 7 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 7 Column: c

Contract for electric service dated 5/1/1984.

Schedule Page: 326 Line No.: 8 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 8 Column: c

Various agreements for purchased power from customers pursuant to the Company's PR-1 (Small Power Production, Cogeneration) Rate Schedule.

Schedule Page: 326 Line No.: 10 Column: c

Docket Nos. ER01-1043-000 and ER03-237-000.

Schedule Page: 326 Line No.: 10 Column: l

Barter arrangement for transmission ancillary services 1, 2, 5 and 6.

Schedule Page: 326 Line No.: 11 Column: a

Affiliated company.

Schedule Page: 326 Line No.: 11 Column: c

FERC Electric Rate Schedule No. 1, Schedule 8 Billing Format - Cost of Service Tariff Docket Nos. ER85-204-007 and ER85-603-005.

Schedule Page: 326 Line No.: 12 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 12 Column: c

FERC Electric Rate Schedule No. 1, Docket No. ER10-2712.

Schedule Page: 326 Line No.: 13 Column: b

OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement.

Schedule Page: 326 Line No.: 13 Column: c

Tariff No. 5, Docket No. ER12-2322.

Schedule Page: 326 Line No.: 14 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326 Line No.: 14 Column: c

FERC Electric Tariff Volume No. 3, Docket No. ER14-1625.

Schedule Page: 326.1 Line No.: 2 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 2 Column: c

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 6/1/2003.

Schedule Page: 326.1 Line No.: 3 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 3 Column: c

Tariff #1

Schedule Page: 326.1 Line No.: 4 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 4 Column: c

Tariff #1, Docket No. ER10-2778.

Schedule Page: 326.1 Line No.: 5 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 5 Column: c

Tariff No. 4, Docket No. ER10-2881.

Schedule Page: 326.1 Line No.: 6 Column: b

OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement.

Schedule Page: 326.1 Line No.: 6 Column: c

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2004.

Schedule Page: 326.1 Line No.: 7 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 7 Column: c

FERC Electric Rate Schedule No. 29.

Schedule Page: 326.1 Line No.: 8 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 8 Column: c

FERC Electric Rate Schedule No. 42.

Schedule Page: 326.1 Line No.: 10 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 10 Column: c

FERC Electric Rate Schedule No. 33.

Schedule Page: 326.1 Line No.: 11 Column: b

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

Schedule Page: 326.1 Line No.: 11 Column: c

SCPSA Docket No. 2015-363-E.

Schedule Page: 326.1 Line No.: 12 Column: b

IU - Service from designated generating unit(s) with duration longer than one year but less than five years.

Schedule Page: 326.1 Line No.: 12 Column: c

Tariff No. 1, Docket No. ER10-1892.

Schedule Page: 326.1 Line No.: 12 Column: l

Scheduling Charges.

Schedule Page: 326.1 Line No.: 13 Column: b

IF - Firm service with duration longer than one year but less than five years. Earliest termination date is 12/31/2016.

Schedule Page: 326.1 Line No.: 13 Column: c

Tariff No. 4, Docket No. ER10-2881.

Schedule Page: 326.1 Line No.: 14 Column: a

Termination date is December 31, 2016 with evergreen provisions and requires a 4-year written notice by either party to terminate the agreement.

Schedule Page: 326.1 Line No.: 14 Column: c

Contract for electric service dated 1/7/1997.

Schedule Page: 326.2 Line No.: 1 Column: b

EX - Exchanges of electricity.

Schedule Page: 326.2 Line No.: 1 Column: c

Electric service provided under SCE&G's OATT Schedules 4 and 9.

Schedule Page: 326.2 Line No.: 1 Column: h

Over delivery of energy by Columbia Energy LLC.

Schedule Page: 326.2 Line No.: 1 Column: i

Under delivery of energy by Columbia Energy LLC.

Schedule Page: 326.2 Line No.: 2 Column: l

Reflects amortization of previously deferred purchase power and capacity charges of $282,658 and $1,525,713 respectively per SCPSC Docket No. 2009-489-E.

Reflects amortization of previously deferred amounts per SCPSC Docket No. 2009-489-E of $876,797.

Reflects the deferral of short-term capacity purchases from Southern Company Services, Inc. per SCPSC Docket Nos. 2008-230-E and 2012-218-E of ($87,200).

Reflects the deferral of capacity purchases from Columbia Energy LLC and Southern Company Services, Inc. per SCPSC Docket No. 2013-276-E of ($4,329,172).

Reflects fuel expense of $1,065,513 for Company-owned fuel oil used by Columbia Energy LLC for generation.

Reflects the deferral of purchase power of ($1,513) pursuant to SCPSC Docket No. 2015-54-E, under the Company's Distributed Energy Resources (DER) program.

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Southern Company Services, Inc.	Duke Energy Carolinas, LLC	Georgia Power Company	NF
2	Duke Energy Progress, LLC	Georgia Power Company	Duke Energy Progress, LLC	SFP
3	The Energy Authority, Inc.	Georgia Power Company	SC Public Service Authority	SFP
4	The Energy Authority, Inc.	Georgia Power Company	SC Public Service Authority	NF
5	SC Public Service Authority	SC Public Service Authority	Various	FNO
6	Southeastern Power Administration	Southeastern Power Administration	Various	FNO
7	City of Orangeburg	South Carolina Electric & Gas Co	City of Orangeburg	FNO
8	Central Electric Power Co-op	SC Public Service Authority	Central Electric Power Co-op	FNO
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34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
T5.S8, S1, S2	DUK	SOCO		164	160	1
T5.S7, S1, S2	SOCO	CPLE	102	990	970	2
T5.S7,S1, S2	SOCO	SC	302	6,680	6,546	3
T5.S8, S1, S2	SOCO	SC		422	410	4
T5, Attach H			710	305,354	296,459	5
T5, Attach H			216	29,916	28,871	6
T5, Attach H			1,631	876,166	850,648	7
T5, Attach H			72	26,955	26,427	8
						9
						10
						11
						12
						13
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						34
			3,033	**1,246,647**	**1,210,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,248		71	1,319	1
9,670		640	10,310	2
40,084		2,072	42,156	3
3,276		187	3,463	4
1,948,161		107,056	2,055,217	5
606,917		69,573	676,490	6
4,468,430		587,836	5,056,266	7
202,061		11,095	213,156	8
				9
				10
				11
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				31
				32
				33
				34
7,279,847	**0**	**778,530**	**8,058,377**	

Schedule Page: 328 Line No.: 1 Column: h
Non-firm hourly billing demand of 164.
Schedule Page: 328 Line No.: 1 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 1 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 1 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 2 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 2 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 2 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 3 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 3 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 3 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 4 Column: h
Non-firm hourly billing demand of 445.
Schedule Page: 328 Line No.: 4 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 4 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 4 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 5 Column: e
Also includes Rate Schedules S1 and S2 of Tariff.
Schedule Page: 328 Line No.: 5 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 5 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 5 Column: m
Sum of Ancillary Service 1 and 2 charges.
Schedule Page: 328 Line No.: 5 Column: n
Network transmission revenue.
Schedule Page: 328 Line No.: 6 Column: e
Also includes Rate Schedules S1, S2, S5 and S6 of Tariff.
Schedule Page: 328 Line No.: 6 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 6 Column: j
Actual energy flows in MWH are listed rather than transmission reservation quantities.
Schedule Page: 328 Line No.: 6 Column: m
Sum of Ancillary Service 1, 2, 5 and 6 charges.
Schedule Page: 328 Line No.: 6 Column: n
Network transmission revenue.
Schedule Page: 328 Line No.: 7 Column: e
Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.
Schedule Page: 328 Line No.: 7 Column: i
Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 7 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 7 Column: m

Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.

Schedule Page: 328 Line No.: 7 Column: n

Network transmission revenue.

Schedule Page: 328 Line No.: 8 Column: e

Also includes Rate Schedules S1 and S2 of Tariff.

Schedule Page: 328 Line No.: 8 Column: i

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 8 Column: j

Actual energy flows in MWH are listed rather than transmission reservation quantities.

Schedule Page: 328 Line No.: 8 Column: m

Sum of Ancillary Service 1 and 2 charges.

Schedule Page: 328 Line No.: 8 Column: n

Network transmission revenue.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Carolinas	FNS	5,020	4,623	14,203	-8,791	16,095	21,507
2	Duke Energy Carolinas	NF	2,760		5,593	816	1,048	7,457
3	PJM Settlement, Inc.	NF	550		368	-60	637	945
4	Southern Co Svcs, Inc	SFP	227,637		3,209,472		245,510	3,454,982
5	Adjustments						-784,310	-784,310
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		235,967	4,623	3,229,636	-8,035	-521,020	2,700,581

Schedule Page: 332 Line No.: 1 Column: g

Scheduling, System Control and Dispatch	$	303
Reactive Supply and Voltage Control		1,917
Regulation and Frequency Response		364
Operating Reserve - Spinning		781
Operating Reserve - Supplement		781
Other - Direct Assignment Charges		11,949
Total	$	16,095

Schedule Page: 332 Line No.: 2 Column: g

Scheduling, System Control and Dispatch	$	121
Reactive Supply and Voltage Control		927
Total	$	1,048

Schedule Page: 332 Line No.: 3 Column: g

Scheduling, System Control and Dispatch	$	175
Reactive Supply and Voltage Control		109
Operating Reserve - Spinning		294
Other - Black Start Service		17
Other - Day-Ahead Load Response Charge Allocation		1
Other - FERC Annual Charge Recovery		37
Other - Market Monitoring Unit(MMU)Funding		2
Other - PJM Settlement, Inc.		2
Total	$	637

Schedule Page: 332 Line No.: 4 Column: g

Scheduling, System Control and Dispatch	$	96,720
Reactive Supply and Voltage Control		132,000
Other - FERC Annual Charge Recovery		14,858
Other - Recovery of Attachment K Charge Factor		1,932
Total	$	245,510

Schedule Page: 332 Line No.: 5 Column: g

Columbia Energy LLC Reactive Supply and Voltage Control (RSV) to SCE&G	$ 488,000
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services, Inc. pursuant to SCPSC Docket No. 2013-276-E.	(1,270,713)
Southern Company Servies, Inc. refund calculated on Transmission Service for 2014	(1,597)
Total	($ 784,310)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	465,877
2	Nuclear Power Research Expenses	611,529
3	Other Experimental and General Research Expenses	1,029,019
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	272,613
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Other Business Expenses	36,907
7	Transportation and Other Power Operated Equipment	18,676
8	Travel excluding Meals	2,776
9	Meals	3,772
10	Computer Hardware and Software Maintenance	50,491
11	Utilities	12,084
12	Telephone Resource Usage	48,007
13	Directors Fees and Expenses	1,362,460
14	Outside Services	73,696
15	Computer Resource Usage, Software, Hardware and	
16	Network Services	119,280
17	Company Payroll	59,254
18	Aircraft Transportation	50,284
19	Depreciation, Amortization and Property Tax Charges	
20	billed from SCANA Services	11,902,937
21	Postage	3,019
22	Research & Development Grant Amortization	100,000
23	Miscellaneous	3,773
24		
25		
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27		
28		
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46	TOTAL	16,226,454

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			4,944,716		4,944,716
2	Steam Production Plant	67,834,881				67,834,881
3	Nuclear Production Plant	17,014,756				17,014,756
4	Hydraulic Production Plant-Conventional	2,090,153				2,090,153
5	Hydraulic Production Plant-Pumped Storage	2,266,768				2,266,768
6	Other Production Plant	25,044,685				25,044,685
7	Transmission Plant	26,664,150				26,664,150
8	Distribution Plant	68,583,478				68,583,478
9	Regional Transmission and Market Operation					
10	General Plant	4,766,407				4,766,407
11	Common Plant-Electric	5,913,529		3,499,009		9,412,538
12	TOTAL	220,178,807		8,443,725		228,622,532

B. Basis for Amortization Charges

Electric Intangible Plant (Account 404) consists of the following:
Amortization of Saluda Hydro Project #516, Stevens Creek Project #2535, Neal Shoals Project #2315 and relicensing costs associated with V. C. Summer Nuclear Station. The charges were based on plant balances of Saluda - $793,257, Stevens Creek - $2,268,402 and Neal Shoals - $1,507,161. The associated costs of relicensing the V. C. Summer Nuclear Plant through 2042 is $8,564,832.

Amortization of a steam generator at a cogeneration facility over the contractual term of the facility. The amortization is based on a gross plant amount of $11,144,060.

Data processing software costs of $64,042,084 are being amortized over the expected life of the software application.

Common Plant - Electric (Account 404):
Amortization of data processing software of $130,039,838 over the expected life of the software application.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production:						
13	Urquhart - 311	16,763	85.00	-25.00	4.04	R2	13.10
14	Urquhart - 312	22,213	40.00	-30.00	9.59	S0	11.20
15	Urquhart - 314	51,640	50.00	-25.00	5.17	S0.5	12.60
16	Urquhart - 315	12,431	60.00	-15.00	4.29	R2.5	12.90
17	Urquhart - 316	5,028	42.00	-5.00	6.68	R0.5	12.40
18	Total Urquhart	108,075					
19							
20	McMeekin - 311	20,985	85.00	-25.00	5.05	R2	13.20
21	McMeekin - 312	133,626	40.00	-30.00	6.73	S0	12.10
22	McMeekin - 314	38,286	50.00	-25.00	5.90	S0.5	12.60
23	McMeekin - 315	11,742	60.00	-15.00	4.57	R2.5	13.30
24	McMeekin - 316	5,210	42.00	-5.00	4.55	R0.5	12.20
25	Total McMeekin	209,849					
26							
27	Cope - 311	82,277	85.00	-25.00	1.61	R2	50.60
28	Cope - 312	261,967	40.00	-30.00	2.95	S0	29.10
29	Cope - 312 SCR	69,886	40.00	-30.00	2.95	S0	29.10
30	Cope - 314	87,153	50.00	-25.00	2.01	S0.5	34.30
31	Cope - 315	24,177	60.00	-15.00	1.48	R2.5	41.80
32	Cope - 316	10,847	42.00	-5.00	2.08	R0.5	33.60
33	Cope - 316 SCR	618	42.00	-5.00	2.08	R0.5	33.60
34	Total Cope	536,925					
35							
36	Jasper - 312	471	40.00	-30.00	3.41	S0	34.00
37	Jasper - 314	99,728	50.00	-25.00	2.63	S0.5	40.00
38	Jasper - 315	6,635	60.00	-15.00	1.77	R2.5	48.60
39	Jasper - 316	300	42.00	-5.00	2.44	R0.5	38.70
40	Total Jasper	107,134					
41							
42	Central Lab - 311	3,593	85.00	-25.00	4.26	R2	13.30
43	Central Lab - 315	59	60.00	-15.00	2.50	R2.5	12.80
44	Central Lab - 316	2,549	42.00	-5.00	6.09	R0.5	12.40
45	Total Central Lab	6,201					
46							
47	Wateree - 311	55,168	85.00	-25.00	3.32	R2	29.30
48	Wateree - 311 Scrubb	81,003	85.00	-25.00	3.32	R2	29.30
49	Wateree - 312	369,309	40.00	-30.00	3.97	S0	24.10
50	Wateree - 312 Scrubb	214,267	40.00	-30.00	3.97	S0	24.10

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Wateree - 314	143,922	50.00	-25.00	3.06	S0.5	25.90
13	Wateree - 315	29,083	60.00	-15.00	2.72	R2.5	27.90
14	Wateree - 316	6,463	42.00	-5.00	2.67	R0.5	24.30
15	Total Wateree	899,215					
16							
17	Nuclear Production:						
18	V.C. Summer -321	281,071	85.00	-3.00	1.07	R2	42.20
19	V.C. Summer -322	506,153	60.00	-4.00	1.36	R2.5	35.90
20	V.C. Summer -323	110,985	50.00	-5.00	2.20	S0.5	31.60
21	V.C. Summer -324	111,928	55.00	-2.00	1.18	R3	29.50
22	V.C. Summer -325	110,612	31.00	-4.00	3.95	R2	19.10
23	Total V.C. Summer	1,120,749					
24							
25	Hydro Production - Conv						
26	Neal Shoals - 331	740	105.00	-10.00	1.14	R2	38.60
27	Neal Shoals - 332	3,629	125.00	-15.00	2.36	R2.5	38.60
28	Neal Shoals - 333	3,755	85.00	-15.00	1.52	R1.5	37.10
29	Neal Shoals - 334	379	60.00	-15.00	1.73	R0.5	33.70
30	Neal Shoals - 335	349	65.00	-10.00	1.39	R1.5	35.40
31	Neal Shoals - 336	3	70.00		0.64	R4	35.90
32	Total Neal Shoals	8,855					
33							
34	Parr - 331	1,884	105.00	-10.00	2.13	R2	46.00
35	Parr - 332	4,722	125.00	-15.00	1.38	R2.5	47.70
36	Parr - 333	2,716	85.00	-15.00	1.95	R1.5	45.40
37	Parr - 334	1,960	60.00	-15.00	1.88	R0.5	39.10
38	Parr - 335	456	65.00	-10.00	1.83	R1.5	42.70
39	Parr - 336	124	70.00		0.78	R4	46.80
40	Total Parr	11,862					
41							
42	Stevens Ck - 331	2,909	105.00	-10.00	0.89	R2	58.50
43	Stevens Ck - 332	6,430	125.00	-15.00	0.87	R2.5	61.80
44	Stevens Ck - 333	2,462	85.00	-15.00	0.98	R1.5	55.30
45	Stevens Ck - 334	1,079	60.00	-15.00	1.13	R0.5	44.50
46	Stevens Ck - 335	1,013	65.00	-10.00	1.12	R1.5	48.80
47	Stevens Ck - 336	129	70.00		1.04	R4	56.30
48	Total Stevens Ck	14,022					
49							
50	Saluda - 331	7,708	105.00	-10.00	1.29	R2	59.30

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Saluda - 332	21,829	125.00	-15.00	0.87	R2.5	57.00
13	Saluda - 332.5						
14	(Backup Dam)	332,846	125.00		0.34	R2.5	64.40
15	Saluda - 333	9,987	85.00	-15.00	1.28	R1.5	50.20
16	Saluda - 334	1,556	60.00	-15.00	1.58	R0.5	43.20
17	Saluda - 335	1,782	65.00	-10.00	1.72	R1.5	50.50
18	Saluda - 336	234	70.00		0.89	R4	44.10
19	Total Saluda	375,942					
20							
21	Hydro Production -						
22	Pumped Storage:						
23	Fairfield - 331	36,310	105.00	-10.00	0.86	R2	73.20
24	Fairfield - 332	74,795	125.00	-15.00	0.81	R2.5	85.90
25	Fairfield - 333	67,470	85.00	-15.00	1.36	R1.5	63.80
26	Fairfield - 334	21,397	60.00	-15.00	2.06	R0.5	52.20
27	Fairfield - 335	6,268	65.00	-10.00	1.70	R1.5	47.70
28	Fairfield - 336	1,328	70.00		1.25	R4	34.60
29	Total Fairfield	207,568					
30							
31	Other Production - Gas						
32	Hardeeville - 341	58	45.00	-5.00	13.11	R2.5	3.50
33	Hardeeville - 342	534	45.00	-15.00	8.81	S1	3.50
34	Hardeeville - 343	799	28.00	-10.00	8.29	R2.5	3.40
35	Hardeeville - 344	1,863	60.00	-10.00	15.62	S1.5	3.40
36	Hardeeville - 345	283	40.00	-10.00	20.02	S2	3.40
37	Hardeeville - 346	74	38.00		27.75	R1	3.40
38	Total Hardeeville	3,611					
39							
40	Coit - 341	182	45.00	-5.00	1.80	R2.5	14.00
41	Coit - 342	568	45.00	-15.00	1.74	S1	13.70
42	Coit - 343	1,138	28.00	-10.00	2.36	R2.5	12.90
43	Coit - 344	3,500	60.00	-10.00	0.64	S1.5	12.50
44	Coit - 345	628	40.00	-10.00	3.50	S2	14.20
45	Coit - 346	162	38.00		1.75	R1	13.40
46	Total Coit	6,178					
47							
48	Parr - 341	878	45.00	-5.00	3.29	R2.5	14.70
49	Parr - 342	576	45.00	-15.00	2.61	S1	12.50
50	Parr - 343	4,132	28.00	-10.00	7.16	R2.5	13.60

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Parr - 344	3,563	60.00	-10.00	1.10	S1.5	13.80
13	Parr - 345	1,096	40.00	-10.00	3.65	S2	14.90
14	Parr - 346	199	38.00		3.71	R1	13.90
15	Total Parr	10,444					
16							
17	Bushy Park - 341	596	45.00	-5.00	2.08	R2.5	34.60
18	Bushy Park - 342	159	45.00	-15.00	0.94	S1	32.60
19	Bushy Park - 343	6,345	28.00	-10.00	1.89	R2.5	16.70
20	Bushy Park - 344	77	60.00	-10.00	0.77	S1.5	38.10
21	Bushy Park - 345	306	40.00	-10.00	2.18	S2	31.10
22	Bushy Park - 346	117	38.00		1.56	R1	29.50
23	Total Bushy Park	7,600					
24							
25	Hagood - 341	3,457	45.00	-5.00	1.26	R2.5	25.30
26	Hagood - 342	808	45.00	-15.00	0.86	S1	23.40
27	Hagood - 343	24,145	28.00	-10.00	2.24	R2.5	10.90
28	Hagood - 344	6,035	60.00	-10.00	1.08	S1.5	29.40
29	Hagood - 345	2,708	40.00	-10.00	1.56	S2	21.90
30	Hagood - 346	348	38.00		2.84	R1	27.80
31	Total Hagood	37,501					
32							
33	Jasper - 341	28,120	45.00	-5.00	2.16	R2.5	35.80
34	Jasper - 342	6	45.00	-15.00	2.66	S1	37.40
35	Jasper - 343	304,252	28.00	-10.00	3.54	R2.5	18.90
36	Jasper - 344	32,737	60.00	-10.00	1.74	S1.5	46.70
37	Jasper - 345	31,227	40.00	-10.00	2.47	S2	29.70
38	Jasper - 346	550	38.00		2.90	R1	33.10
39	Total Jasper	396,892					
40							
41	Urq 1 & 2 - 341	1,269	45.00	-5.00	3.06	R2.5	27.00
42	Urq 1 & 2 - 342	189	45.00	-15.00	2.74	S1	24.00
43	Urq 1 & 2 - 343	633	28.00	-10.00	3.79	R2.5	21.60
44	Urq 1 & 2 - 344	3,408	60.00	-10.00	2.20	S1.5	22.60
45	Urq 1 & 2 - 345	196	40.00	-10.00	4.26	S2	21.70
46	Urq 1 & 2 - 346	92	38.00		3.39	R1	24.20
47	Total Urq 1 & 2	5,787					
48							
49	Urq 3 - 341	354	45.00	-5.00	6.48	R2.5	14.20
50	Urq 3 - 342	8	45.00	15.00	3.82	S1	13.80

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Urq 3 - 343	215	28.00	-10.00	7.54	R2.5	13.90
13	Urq 3 - 344	2,191	60.00	-10.00	2.83	S1.5	13.10
14	Urq 3 - 345	56	40.00	-10.00	6.09	S2	14.20
15	Total Urq 3	2,824					
16							
17	Urq 4 - 341	316	45.00	-5.00	0.83	R2.5	31.00
18	Urq 4 - 342	968	45.00	-15.00	0.60	S1	30.10
19	Urq 4 - 343	2,480	28.00	-10.00	3.77	R2.5	25.90
20	Urq 4 - 344	20,420	60.00	-10.00	1.36	S1.5	36.40
21	Urq 4 - 345	471	40.00	-10.00	2.23	S2	30.80
22	Urq 4 - 346	62	38.00		2.34	R1	31.40
23	Total Urq 4	24,717					
24							
25	Urq 5 & 6 - 341	4,752	45.00	-5.00	1.80	R2.5	34.00
26	Urq 5 & 6 - 342	3,609	45.00	-15.00	1.76	S1	33.30
27	Urq 5 & 6 - 343	228,562	28.00	-10.00	3.51	R2.5	17.70
28	Urq 5 & 6 - 344	13,383	60.00	-10.00	1.79	S1.5	44.80
29	Urq 5 & 6 - 345	17,110	40.00	-10.00	2.23	S2	28.10
30	Urq 5 & 6 - 346	137	38.00		2.47	R1	34.30
31	Total Urq 5 & 6	267,553					
32							
33	Boeing Solar - 341	117	45.00	-5.00	5.44	R2.5	16.30
34	Boeing Solar - 344	7,031	60.00	-10.00	5.65	S1.5	16.60
35	Boeing Solar - 345	2,197	40.00	-10.00	5.68	S2	16.50
36	Boeing Solar - 346	18	38.00		5.31	R1	15.40
37	Total Boeing Solar	9,363					
38							
39	Hagood ICT U5 341	350	45.00	-5.00	2.32	R2.5	40.00
40	Hagood ICT U5 342	337	45.00	-15.00	2.63	S1	38.60
41	Hagood ICT U5 343	4,979	28.00	-10.00	2.07	R2.5	24.00
42	Hagood ICT U5 344					0	
43	Hagood ICT U5 345	2,131	40.00	-10.00	2.86	S2	35.30
44	Hagood ICT U5 346					0	
45	Total Hagood ICT U5	7,797					
46							
47	Hagood ICT U6 341	683	45.00	-5.00	2.32	R2.5	40.00
48	Hagood ICT U6 342	419	45.00	-15.00	2.63	S1	38.60
49	Hagood ICT U6 343	5,533	28.00	-10.00	2.12	R2.5	23.80
50	Hagood ICT U6 344	4	60.00	-10.00	2.11	S1.5	48.70

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Hagood ICT U6 345	3,273	40.00	-10.00	2.76	S2	35.30
13	Hagood ICT U6 346	22	38.00		2.58	R1	34.10
14	Total Hagood ICT U6	9,934					
15							
16	Transmission:						
17	Nuclear - 352	330	65.00	-10.00	1.52	R2	24.10
18	Other - 352	3,529	65.00	-10.00	1.78	R2	51.20
19	Parr - 352	142	60.00	-15.00	2.29	S0.5	22.60
20	Saluda - 352	431	60.00	-15.00	2.30	S0.5	29.50
21	Stevens Creek - 352	38	60.00	-15.00	4.58	S0.5	18.60
22	Nuclear - 353	18,025	60.00	-15.00	3.28	S0.5	25.80
23	Parr - 353	376	60.00	-15.00	2.29	S0.5	22.60
24	Fairfield - 353	1,150	60.00	-15.00	0.40	S0.5	45.10
25	Saluda - 353	8,330	60.00	-15.00	2.30	S0.5	29.50
26	Stevens Ck - 353	4,615	60.00	-15.00	4.58	S0.5	18.60
27	Neal Shoals - 353	27	60.00	-15.00	0.22	S0.5	14.30
28	Nuclear Step-up - 353	13,746	55.00	-15.00	3.62	S2.5	26.30
29	Parr Step-up - 353	397	55.00	-15.00	2.53	S2.5	17.20
30	Fairfield Step-up-353	7,699	55.00	-15.00	1.85	S2.5	46.20
31	Saluda Step-up - 353	595	55.00	-15.00	1.51	S2.5	22.90
32	Wateree Step-up - 353	5,571	55.00	-15.00	4.21	S2.5	24.40
33	McMeekin Step-up - 353	819	55.00	-15.00	2.36	S2.5	13.60
34	Urq Steam Step-up-353	1,366	55.00	-15.00	1.88	S2.5	9.50
35	Wms Steam Step-up-353	1,809	55.00	-15.00	2.21	S2.5	25.10
36	Cope Step-up - 353	6,020	55.00	-15.00	2.18	S2.5	34.10
37	Williams GT - 353	8,351	55.00	-15.00	1.97	S2.5	9.00
38	Jasper Step-up - 353	19,101	55.00	-15.00	2.21	S2.5	40.50
39	Burton Step-up - 353					0	
40	Hardeeville Step-up353	118	55.00	-15.00	1.60	S2.5	15.80
41	Coit Step-up - 353	118	55.00	-15.00	1.04	S2.5	1.50
42	Hagood Step-up - 353	2,598	55.00	-15.00	1.31	S2.5	28.10
43	Stevens Crk Step-up353	404	55.00	-15.00	1.92	S2.5	29.10
44	Urquhart GT Step-up353	1,047	55.00	-15.00	2.70	S2.5	1.00
45	Bsh Park GT Step-up353	150	55.00	-15.00	1.97	S2.5	9.00
46	Station Equip - 353	335,017	60.00	-15.00	1.81	S0.5	47.90
47	Station Equip -						
48	CIPV5 - 353	7,446	60.00	-15.00	1.81	S0.5	47.90
49	Station Equip -						
50	Leasehold - 353.8	1,464	20.00		5.90	SQ	9.30

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	354	5,365	75.00	-40.00	1.37	R3	40.00
13	Neal Shoals - 354	49	60.00	-15.00	0.22	S0.5	14.30
14	355	355,926	53.00	-70.00	3.33	L2	41.60
15	Neal Shoals - 355	21	60.00	-20.00	0.22	S0.5	14.30
16	355.8	2,182	20.00		5.74	SQ	16.70
17	356.1	206,801	60.00	-45.00	2.50	R2.5	43.70
18	356.2	2,767	60.00	-45.00	2.47	R2.5	45.80
19	356.8	1,089	20.00		11.57	SQ	4.00
20	357	20,725	60.00		1.62	R3	52.30
21	358	62,616	50.00		1.96	R3	44.70
22	359	74	65.00		1.41	R4	55.60
23	Total Transmission	1,108,444					
24							
25	Distribution Plant:						
26	361	4,844	65.00	-10.00	1.70	R2	52.50
27	361.8	67	20.00		11.30	SQ	4.50
28	362	371,933	60.00	-10.00	1.93	S0.5	47.40
29	362.8	3,455	20.00		5.52	SQ	13.40
30	364	435,508	43.00	-30.00	3.12	R1.5	32.70
31	365	478,008	57.00	-10.00	1.68	R1.5	46.60
32	URD - 366	137,686	60.00	-5.00	1.46	R2.5	49.00
33	Network - 366	7,663	60.00	-5.00	1.46	R2.5	49.00
34	URD - 367	420,784	49.00	-5.00	1.92	S0.5	39.50
35	Network - 367	10,202	49.00	-5.00	1.92	S0.5	39.50
36	368	453,720	45.00	-5.00	2.04	R2	33.30
37	O/H - 369	104,130	65.00	-70.00	2.42	R3	46.30
38	U/G - 369	171,039	65.00	-70.00	2.42	R3	46.30
39	370	21,242	22.00		2.62	L1	17.40
40	370.3	67,914	15.00		9.59	L3	9.40
41	370.4	11,368	15.00		8.64	S2.5	11.20
42	373	294,850	37.00	-15.00	2.89	S0.5	28.30
43	Total Distribution	2,994,413					
44							
45	General Plant:						
46	3901	137,600	50.00	-10.00	1.91	S0	44.50
47	3902	10,041	50.00	-10.00	2.27	R2.5	42.90
48	3908	145	50.00	-10.00	0.53	S0	35.30
49	3909	111	50.00	-10.00	2.79	R2.5	28.10
50	3911	8,084	20.00		5.25	SQ	13.50

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	3912	2,824	5.00		20.00	SQ	1.80
13	3913	324	20.00		6.43	SQ	9.00
14	3919					0	
15	393	270	25.00		3.52	SQ	6.40
16	3941	554	20.00		5.33	SQ	10.10
17	3942	2,714	20.00		3.10	SQ	14.40
18	3943	257	20.00		6.78	SQ	7.60
19	3944	283	20.00		6.90	SQ	11.30
20	3951	1,746	20.00		1.86	SQ	14.50
21	3952	527	20.00		5.34	SQ	12.10
22	3953	4,005	20.00		5.01	SQ	10.80
23	397	7,392	8.00		5.09	SQ	4.30
24	398	5,997	20.00		3.75	SQ	13.20
25	Total General Plant	182,874					
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
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39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 12 Column: a

Method of Determination of Depreciation Charges:

The Annual Provisions for Depreciation of Property, with the exception of major construction, are based on straight line rates applied to the prior month ending plant balances. The Annual Provision for Depreciation of major construction projects, if any, are computed based on the number of days that the plant was in service.

In addition to Depreciation Provisions provided by the application of the reported rates herein, the Company also recognized $3,958,253 of electric and $748,889 of common depreciation related to vehicles, as well as, $3,788,787 of electric and $3,878,420 of common amortization related to software over their expected useful lives using the straight line method. See allocation of Common Plant on pages 356.1 and 356.2.

The Company also recognized amortization of a steam generator at a cogeneration facility over the contractual term of the facility. The amortization was based on a gross plant amount of $11,144,060.

Schedule Page: 336 Line No.: 12 Column: b

Balances in column (b) reflect depreciable plant balances as of December 31, 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	State assessment for the support of the				
2	Public Service Commission of South				
3	Carolina (SCPSC) and annual charges assessed				
4	by the Federal Energy Regulatory				
5	Commission (FERC).	4,885,748		4,885,748	
6					
7	Company labor, legal and miscellaneous				
8	expenses related to proceedings before the				
9	SCPSC.		43,661	43,661	
10					
11	Company labor, legal and miscellaneous				
12	expenses related to Dockets associated with				
13	Revisions and Updates for the Construction and				
14	Operation of a Nuclear Facility in				
15	Jenkinsville, SC, related to proceedings				
16	before the SCPSC.		31,891	31,891	
17					
18	Company labor, legal, consulting and				
19	miscellaneous expenses related to proceedings				
20	before the FERC.		224,809	224,809	
21					
22	Company labor, legal and miscellaneous				
23	expenses associated with the Distributed				
24	Energy Resources Program Act before the SCPSC				
25	Docket No. 2014-214-E.		59,040	59,040	
26					
27	Incremental Company Expenses related to Docket				
28	No. 2009-489-E, Application for Increases and				
29	Adjustments in Electric Rate Schedules and				
30	Tariffs, before the SCPSC. Amortization				
31	period July 2010-July 2015.		24,582	24,582	24,582
32					
33	Incremental Company expenses related				
34	to Docket No. 2012-218-E, Application for				
35	Increases and Adjustments in Electric Rate				
36	Schedules and Tariffs, before the SCPSC.				
37	Amortization period of				
38	January 2013 - December 2015.		54,860	54,860	54,860
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,885,748	438,843	5,324,591	79,442

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
Electric	928	4,885,748					5
							6
							7
							8
Electric	928	43,661					9
							10
							11
							12
							13
							14
							15
Electric	928	31,891					16
							17
							18
							19
Electric	928	224,809					20
							21
							22
							23
							24
Electric	928	59,040					25
							26
							27
							28
							29
							30
Electric				928	24,582		31
							32
							33
							34
							35
							36
							37
Electric				928	54,860		38
							39
							40
							41
							42
							43
							44
							45
		5,245,149			79,442		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed Internally	
2	(1) Generation	EPRI Coordination
3		Technology Transfer
4	(2) Transmission	EPRI Coordination
5		Technology Transfer
6	(3) Distribution	EPRI Coordination
7		Technology Transfer
8	(4) Other	
9	Power Quality	EPRI Coordination
10	Total Internally	
11	B. Electric R,D and D Performed Externally	
12	(1) Research Support to EPRI	
13	Fossil Steam Plants and Combustion	
14	Turbines - Programs	Boiler and Turbine Steam and Cycle Chemistry
15		Combined Cycle HRSG and Balance of Plant
16		Generation Maintenance Applications Center
17		Operations Management & Technology
18		Air Toxics Health and Risk Assessment
19		Coal Combustion Products - Envrionmental Issues
20		Fish Protection at Steam Electric Power Plants
21		Effluent Guidelines and Water Quality Management
22		Power Plant Multimedia Toxics Characterization
23		Air Quality Assessment of Ozone, Particulate Matter, Visibility and
24		Deposition
25	Nuclear Power - Programs	
26		Nuclear Power
27		Steam Turbines, Generators and Balance-of-Plant
28	Transmission and Substation - Programs	
29		Structure and Sub-Grade Corrosion Management
30		Lightning Performance and Grounding of Transmission Lines
31		Transmission Line Design Tools
32		Polymer and Composite Overhead Transmission Line Components
33		Ratings for Overhead Lines
34		High Temperature Operation of Overhead Lines
35		Technology Transfer for Underground Transmission
36		Transformer Life Management
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
97,438		Various	97,438		2
524		Various	524		3
8,889		Various	8,889		4
9,646		Various	9,646		5
9,908		Various	9,908		6
18,302		Various	18,302		7
					8
2,461		Various	2,461		9
147,168			147,168		10
					11
					12
					13
	21,680	930.2	21,680		14
	79,029	930.2	79,029		15
	17,065	930.2	17,065		16
	47,122	930.2	47,122		17
	63,625	930.2	63,625		18
	54,556	930.2	54,556		19
	66,261	930.2	66,261		20
	62,139	930.2	62,139		21
	68,112	930.2	68,112		22
					23
	70,033	930.2	70,033		24
					25
	611,529	930.2	611,529		26
	53,481	517	53,481		27
					28
	11,019	930.2	11,019		29
	19,295	930.2	19,295		30
	15,507	930.2	15,507		31
	17,911	930.2	17,911		32
	12,309	930.2	12,309		33
	14,066	930.2	14,066		34
	8,253	930.2	8,253		35
	38,176	930.2	38,176		36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Distribution - Programs	
2		Grid Support Functions & Connectivity
3		Technology Transfer and Industry Coordination
4		Distribution Inspection, Maintenance and Asset Planning
5		Tech Transfer and Industry Coordination
6		
7	Cyber Security - Programs	Cyber Security and Privacy Technology Transfer and Industry Collaboration
8		Security Technologies
9		
10	Fossil Steam Plants and Combustion Turbines -	
11	Supplemental Projects	Documentation Support for Coal Combustion Residual (CCR) Public Web
12		Modeling and Model Validation Tools Users Group
13		
14	Nuclear - Supplemental Projects	
15		SGMP - Steam Generator Management Program
16		WRTC - Welding & Repair Technology Center
17		FRP - Fuel Reliability Program (QA)
18		Fuel Works / Cask Loader Users Group
19		NDE - Nondestructive Evaluation Applications and Technology (QA)
20		PDI - Performance Demonstration Training and Qualification (QA)
21		NMAC - Nuclear Maintenance Applications Center
22		Cable Program
23		Nuclear Plan Performance Programs (HXPUG, SWAP, P2EP)
24		SQURTS – Seismic Qualification Reporting and Testing Standardization (QA)
25		Standardized Task Evaluations for Portable Qualifications (STE)
26		Submergence Qualification for Medium-Voltage Cable (QA)
27		CHECWORKS Users Group (CHUG)
28		BPIG - Buried Pipe Integrity Group
29		Phoenix Technology Development (QA)
30		GOTHIC Advisory Group (QA)
31		HRA Calculator User Group (QA)
32		MAAP Users Group
33		Risk and Reliability User Group
34		External Data Hazards Collection
35		SMART chemWORKS User Group - Maintenance and Support
36		Fault Tree Reliability Evaluation eXpert (FTREX)
37		Advanced Nuclear Technology (ANT) New Plant Deployment
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
	25,085	930.2	25,085		2
	16,723	930.2	16,723		3
	23,867	930.2	23,867		4
	11,644	930.2	11,644		5
					6
	19,986	930.2	19,986		7
	49,965	930.2	49,965		8
					9
					10
	20,000	921	20,000		11
	29,700	921	29,700		12
					13
					14
	68,833	524	68,833		15
	16,437	524	16,437		16
	107,438	524	107,438		17
	12,000	107	12,000		18
	38,666	524	38,666		19
	1,667	524	1,667		20
	11,833	524	11,833		21
	2,333	524	2,333		22
	6,400	524	6,400		23
	20,000	107	20,000		24
	9,029	524	9,029		25
	10,000	524	10,000		26
	8,000	524	8,000		27
	10,000	524	10,000		28
	40,000	524	40,000		29
	8,000	524	8,000		30
	6,667	524	6,667		31
	8,667	107	8,667		32
	14,000	524	14,000		33
	10,000	524	10,000		34
	21,000	524	21,000		35
	13,334	524	13,334		36
	137,500	107	137,500		37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Transmission - Projects	
2		SCE&G 2015 PQ Services
3		
4	Distribution - Projects	SCE&G 2015 PQ Services
5		SCE&G 10 MW PV DG Project
6		
7	(2) Research Support to Clemson Univ. Electric	
8	Power Research Association	
9	(3) Research Support to National Electric	
10	Energy Testing and Research Applications	
11	Center	
12	(4) Research Support to Southeast Coastal	
13	Wind Coalition	
14	(5) Research Support to South Carolina	
15	Clean Energy Business Alliance	
16	(6) Research Support to South Carolina	
17	Biomass Council	
18	(7) Research Support to Distributed System	
19	Testing Application and Research	
20	(8) Research Support to Others:	
21	Marketing Research	
22		
23	Total Externally	
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
	20,000	930.2	20,000		2
					3
	20,000	930.2	20,000		4
	10,000	1011	10,000		5
					6
					7
	30,000	930.2	30,000		8
					9
					10
	104,000	930.2	104,000		11
					12
	5,000	921	5,000		13
					14
	4,000	921	4,000		15
					16
	50	921	50		17
					18
	20,000	107	20,000		19
					20
	21,591	930.2	21,591		21
					22
	2,364,583		2,364,583		23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	46,796,741		
4	Transmission	4,425,690		
5	Regional Market			
6	Distribution	6,672,015		
7	Customer Accounts	18,628,867		
8	Customer Service and Informational	2,825,432		
9	Sales	1,270,598		
10	Administrative and General	27,905,923		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	108,525,266		
12	Maintenance			
13	Production	27,214,396		
14	Transmission	2,016,549		
15	Regional Market			
16	Distribution	10,014,190		
17	Administrative and General	1,758,782		
18	TOTAL Maintenance (Total of lines 13 thru 17)	41,003,917		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	74,011,137		
21	Transmission (Enter Total of lines 4 and 14)	6,442,239		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	16,686,205		
24	Customer Accounts (Transcribe from line 7)	18,628,867		
25	Customer Service and Informational (Transcribe from line 8)	2,825,432		
26	Sales (Transcribe from line 9)	1,270,598		
27	Administrative and General (Enter Total of lines 10 and 17)	29,664,705		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	149,529,183	18,884,567	168,413,750
29	Gas			
30	Operation			
31	Production-Manufactured Gas	158,810		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	10,010,668		
37	Customer Accounts	4,054,210		
38	Customer Service and Informational	681,865		
39	Sales	2,906,479		
40	Administrative and General	5,095,510		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	22,907,542		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	28,507		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,655,431		
49	Administrative and General	188,453		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,872,391		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	158,810		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)	28,507		
57	Distribution (Lines 36 and 48)	13,666,099		
58	Customer Accounts (Line 37)	4,054,210		
59	Customer Service and Informational (Line 38)	681,865		
60	Sales (Line 39)	2,906,479		
61	Administrative and General (Lines 40 and 49)	5,283,963		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	26,779,933	3,464,237	30,244,170
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	176,309,116	22,348,804	198,657,920
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	75,948,525	7,953,638	83,902,163
69	Gas Plant	5,682,260	319,269	6,001,529
70	Other (provide details in footnote):		764,652	764,652
71	TOTAL Construction (Total of lines 68 thru 70)	81,630,785	9,037,559	90,668,344
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,462,430	1,857,106	6,319,536
74	Gas Plant	628,773	54,586	683,359
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,091,203	1,911,692	7,002,895
77	Other Accounts (Specify, provide details in footnote):			
78	Non Utility Property		1,598,282	1,598,282
79	Non Operating Expense	3,682,653	629,079	4,311,732
80	Other Work in Progress	55,416	450,597	506,013
81	Other Balance Sheet Payroll	2,573,931	3,591,878	6,165,809
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,312,000	6,269,836	12,581,836
96	TOTAL SALARIES AND WAGES	269,343,104	39,567,891	308,910,995

Schedule Page: 354 Line No.: 70 Column: d

Common Plant

Schedule Page: 354 Line No.: 81 Column: d

DSM Deferrals, PSI accounts, Stores Expense and Temporary Facilities.

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

(1) and (2) See pages 356.1 and 356.2

(3) Common Utility Plant Expenses are not segregated, but charged to utility departments on a functional basis. South Carolina Electric & Gas Company owns all of the Common Utility Plant of SCANA Corporation. Other subsidiaries of SCANA Corporation that benefit from the use of Common Utility Plant are charged directly by South Carolina Electric & Gas Company for their proportionate share of the related expenses.

(4) July 24, 1948

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Utility Plant In Service	Balance End of Year
118-603 Misc Intangible Plant	$130,039,838
118-689 Land and Land Rights	19,313,925
118-690 Structures and Improvements	148,629,458
118-691 Office Furniture and Equipment	13,132,127
118-692 Transportation Equipment	7,458,209
118-693 Stores Equipment	54,392
118-694 Tools, Shop and Garage Equipment	2,093,725
118-695 Laboratory Equipment	151,693
118-696 Power-Operated Equipment	3,791,347
118-697 Communication Equipment	7,724,081
118-698 Miscellaneous Equipment	6,242,985
118-699 ARC Common Gen Plant	80,870
Total	$338,712,650

Note: Common Plant in service consists of land and buildings devoted jointly to all utility operations, such as general office buildings, storerooms and repair shops and equipment therein. Also, software and transportation equipment used jointly is thus classifed.

Construction Work in Progress - Common Utility Plant

Description of Project	Balance End of Year
980065 IVR Infrastructure and App Software	$ 12,602,681
Other Projects < $500K	2,348,387
Total	$ 14,951,068

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Plant in Service and Depreciation Reserve
Allocable to Utility Departments

Common Utility	Total (a)	Electric (b)	Gas (c)
Plant Allocable to Utility Departments (1)	$338,712,650	$305,281,711	$33,430,939
Less:			
Common Depreciable Reserve Allocable to Utility Departments (2)	168,760,716	152,104,033	16,656,683
Net Common Plant Allocable to Utility Departments	$169,951,934	$153,177,678	$16,774,256

(1) This allocation is based on functional use by Departments.
Percentage:Electric 90.13% and Gas 9.87%

(2) This allocation is based on functional use by Departments of common depreciable property.
Percentages are the same as in note (1).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)		14,481	14,481	14,481
3	Net Sales (Account 447)				
4	Transmission Rights		308	308	308
5	Ancillary Services		578	578	578
6	Other Items (list separately)		59	59	59
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL		15,426	15,426	15,426

Schedule Page: 397 Line No.: 2 Column: b

No activity during reported period.

Schedule Page: 397 Line No.: 3 Column: b

No activity during reported period.

Schedule Page: 397 Line No.: 3 Column: c

No activity during reported period.

Schedule Page: 397 Line No.: 3 Column: d

No activity during reported period.

Schedule Page: 397 Line No.: 3 Column: e

No activity during reported period.

Schedule Page: 397 Line No.: 4 Column: b

No activity during reported period.

Schedule Page: 397 Line No.: 5 Column: b

No activity during reported period.

Schedule Page: 397 Line No.: 6 Column: b

No activity during reported period.

Schedule Page: 397 Line No.: 6 Column: c

Other - Black Start Service	$	17
Other - Day-Ahead Load Response Charge Allocation		1
Other - FERC Annual Charge Recovery		37
Other - Market Monitoring Unit Funding		2
Other - PJM Settlement, Inc.		2
Total	$	59

Schedule Page: 397 Line No.: 6 Column: d

Other - Black Start Service	$	17
Other - Day-Ahead Load Response Charge Allocation		1
Other - FERC Annual Charge Recovery		37
Other - Market Monitoring Unit Funding		2
Other - PJM Settlement, Inc.		2
Total	$	59

Schedule Page: 397 Line No.: 6 Column: e

Other - Black Start Service	$	17
Other - Day-Ahead Load Response Charge Allocation		1
Other - FERC Annual Charge Recovery		37
Other - Market Monitoring Unit Funding		2
Other - PJM Settlement, Inc.		2
Total	$	59

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			97,319	8,095	MW	127,610
2	Reactive Supply and Voltage			622,953	8,095	MW	296,358
3	Regulation and Frequency Response			364	1,764	MW	81,840
4	Energy Imbalance	417	MWH	-8,035		MWH	
5	Operating Reserve - Spinning			1,075	1,980	MW	131,661
6	Operating Reserve - Supplement			781	1,980	MW	191,414
7	Other			-1,243,512	3,002	MWH	809,106
8	Total (Lines 1 thru 7)	417		-529,055	24,916		1,637,989

Schedule Page: 398 Line No.: 1 Column: b

Reference footnote Line No. 1 Column D for detail on number of units.

Schedule Page: 398 Line No.: 1 Column: c

Reference footnote Line No. 1 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 1 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 1	.058639	% Load Ratio Share	$ 303
Duke Energy Carolinas, LLC OATT Rate Schedule 1	252 MW/2760 MWH	MW, MWH	121
PJM Settlement, Inc.	550 MW/550 MWH	MW, MWH	175
Southern Company OATT, Rate Schedule 1	100 MW/227,637 MWH	MW, MWH	96,720
Total			$ 97,319

Schedule Page: 398 Line No.: 2 Column: b

Reference footnote Line No. 2 Column D for detail on number of units.

Schedule Page: 398 Line No.: 2 Column: c

Reference footnote Line No. 2 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 2 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 2	.058639	% Load Ratio Share	$ 1,917
Duke Energy Carolinas, LLC OATT Rate Schedule 2	252 MW/2760 MWH	MW, MWH	927
PJM Settlement, Inc.	550 MW/550 MWH	MW, MWH	109
Southern Company OATT, Rate Schedule 2	100 MW/227,637 MWH	MW, MWH	132,000
Columbia Energy LLC Reactive Supply & Voltage Control (RSV) to SCE&G	Flat Rate	Flat Rate	488,000
Total			$ 622,953

Schedule Page: 398 Line No.: 3 Column: b

Reference footnote Line No. 3 Column D for detail on number of units.

Schedule Page: 398 Line No.: 3 Column: c

Reference footnote Line No. 3 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 3 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 3	.058639	% Load Ratio Share	$ 364

Schedule Page: 398 Line No.: 4 Column: b

Reference footnote Line No. 4 Column D for detail on number of units.

Schedule Page: 398 Line No.: 4 Column: c

Reference Line No. 4 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 4 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 4	397	MWH	($ 8,791)
Duke Energy Carolinas, LLC OATT Rate Schedule 4	17	MWH	816
PJM Settlement, Inc.	3	MWH	(60)
Total	417		($ 8,035)

Schedule Page: 398 Line No.: 5 Column: b

Reference footnote Line No. 5 Column D for detail on number of units.

Schedule Page: 398 Line No.: 5 Column: c

Reference footnote Line No. 5 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 5 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 5	.058639	% Load Ratio Share	$ 781
PJM Settlement, Inc.	550 MW/550 MWH	MW, MWH	294
Total			$ 1,075

Schedule Page: 398 Line No.: 6 Column: b

Reference footnote Line No. 6 Column D for detail on number of units.

Schedule Page: 398 Line No.: 6 Column: c

Reference footnote Line No. 6 Column D for detail on unit of measure.

Schedule Page: 398 Line No.: 6 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 6	.058639	% Load Ratio Share	$ 781

Schedule Page: 398 Line No.: 7 Column: d

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC OATT Direct Assignment Charges and Other Miscellaneous Adjustments			$ 11,949
Reflects the deferral of transmission charges relating to the purchase of transmission services from Southern Company Services pursuant to SCPSC Docket No. 2013-276-E			(1,270,713)
Southern Company Services, Inc. FERC Annual Charge Recovery			14,858
Southern Company Services, Inc. Recovery of Attachment K Charge Factor			1,932
Southern Company Services, Inc. Refund calculated on Transmission Service for 2014.			(1,597)
PJM Settlement, Inc. Black Start Service			17
PJM Settlement, Inc. Day-Ahead Load Response Charge Allocation			1
PJM Settlement, Inc. FERC Annual Charge Recovery			37
PJM Settlement, Inc. Market Monitoring Unit Funding			2
PJM Settlement, Inc. Miscellaneous Fees			2
Total			($1,243,512)

Schedule Page: 398 Line No.: 7 Column: e

Generator Imbalance breakdown by MWH:

Net Band 1	Over Delivered	Under Delivered
432	211	2,359

Schedule Page: 398 Line No.: 7 Column: g

Generator Imbalance breakdown by dollar amount:

Net Band 1	Over Delivered	Under Delivered*
$17,566	($4,180)	$795,720

* Reported value for Under Deliveries is net of Generator Imbalance Penalties credited to users of the transmission system.

Schedule Page: 398 Line No.: 8 Column: e

Total is not meaningful due to the summation of dissimilar units of measure.

Schedule Page: 398 Line No.: 8 Column: g

Ancillary Services revenue reported on this schedule is reported as necessary in other supporting schedules within this Form 1 filing.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	5,401	8	800	5,111	290				
2	February	5,433	20	800	5,033	298			102	
3	March	3,532	7	800	3,323	209				
4	Total for Quarter 1				13,467	797			102	
5	April	3,387	9	1700	3,199	188				
6	May	4,176	21	1700	3,961	215				
7	June	4,899	16	1700	4,639	260				
8	Total for Quarter 2				11,799	663				
9	July	4,919	21	1600	4,657	262				
10	August	4,733	5	1500	4,480	253				
11	September	4,469	4	1500	4,248	221				
12	Total for Quarter 3				13,385	736				
13	October	3,277	9	1600	3,119	158				
14	November	3,696	24	800	3,484	212				
15	December	3,541	20	900	3,345	196				
16	Total for Quarter 4				9,948	566				
17	Total Year to Date/Year				48,599	2,762			102	

Schedule Page: 400 Line No.: 1 Column: d

All times shown are in Hour Ending (HE) format.

Schedule Page: 400 Line No.: 1 Column: e

The Company utilizes grandfathered service for its retail customers and has not executed a network integration transmission service agreement under the OATT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	7,081,619
4	Nuclear	4,743,583
5	Hydro-Conventional	384,109
6	Hydro-Pumped Storage	461,014
7	Other	7,334,525
8	Less Energy for Pumping	644,211
9	Net Generation (Enter Total of lines 3 through 8)	19,360,639
10	Purchases	4,954,820
11	Power Exchanges:	
12	Received	211
13	Delivered	2,791
14	Net Exchanges (Line 12 minus line 13)	-2,580
15	Transmission For Other (Wheeling)	
16	Received	370,481
17	Delivered	359,843
18	Net Transmission for Other (Line 16 minus line 17)	10,638
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	24,323,517

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	22,172,583
23	Requirements Sales for Resale (See instruction 4, page 311.)	937,115
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,147
25	Energy Furnished Without Charge	9
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	146,151
27	Total Energy Losses	1,062,512
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	24,323,517

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK: Megawatts (See Instr. 4) (d)	MONTHLY PEAK: Day of Month (e)	MONTHLY PEAK: Hour (f)
29	January	2,131,101	1,804	4,788	8	800
30	February	2,053,835		4,970	20	800
31	March	1,796,345	1,471	3,560	7	800
32	April	1,717,471		3,415	9	1700
33	May	1,998,722	52	3,972	21	1700
34	June	2,374,146	940	4,733	16	1700
35	July	2,524,873		4,750	21	1600
36	August	2,381,061	1,123	4,545	5	1500
37	September	2,059,787		4,297	4	1500
38	October	1,750,605		3,068	9	1600
39	November	1,734,980		3,583	24	800
40	December	1,800,591		3,375	20	900
41	TOTAL	24,323,517	5,390			

Schedule Page: 401 Line No.: 16 Column: b

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from SCE&G's system. The MWH supporting these transactions are included in SCE&G's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,246,647	1,210,491
Page 401a	370,481	359,843
Difference	876,166	850,648

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 7	876,166	850,648
Total	876,166	850,648

Schedule Page: 401 Line No.: 17 Column: b

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from SCE&G's system. The MWH supporting these transactions are included in SCE&G's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j). The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,246,647	1,210,491
Page 401a	370,481	359,843
Difference	876,166	850,648

SCE&G Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 7	876,166	850,648
Total	876,166	850,648

Schedule Page: 401 Line No.: 29 Column: f

All times are shown in Hour Ending (HE) format.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *V.C. Summer (2/3rds)* (b)	Plant Name: *Urquhart* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	PWR	Conventional
3	Year Originally Constructed	1984	1953
4	Year Last Unit was Installed	1984	1955
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	686.40	100.00
6	Net Peak Demand on Plant - MW (60 minutes)	666	94
7	Plant Hours Connected to Load	7301	2208
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	661	96
10	When Limited by Condenser Water	647	95
11	Average Number of Employees	656	61
12	Net Generation, Exclusive of Plant Use - KWh	4743583000	142767000
13	Cost of Plant: Land and Land Rights	880612	2614196
14	Structures and Improvements	281071099	16763443
15	Equipment Costs	839678326	91312813
16	Asset Retirement Costs	8447945	11094507
17	Total Cost	1130077982	121784959
18	Cost per KW of Installed Capacity (line 17/5) Including	1646.3840	1217.8496
19	Production Expenses: Oper, Supv, & Engr	9399979	59376
20	Fuel	45687791	4592064
21	Coolants and Water (Nuclear Plants Only)	3149217	0
22	Steam Expenses	7326705	272852
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2359644	191988
26	Misc Steam (or Nuclear) Power Expenses	37477684	1100611
27	Rents	0	0
28	Allowances	0	6
29	Maintenance Supervision and Engineering	-3055152	31296
30	Maintenance of Structures	3106875	14686
31	Maintenance of Boiler (or reactor) Plant	14474420	246263
32	Maintenance of Electric Plant	3416419	2987831
33	Maintenance of Misc Steam (or Nuclear) Plant	17185353	608649
34	Total Production Expenses	140528935	10105622
35	Expenses per Net KWh	0.0296	0.0708

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear			Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Grams			Barrels	MCF	
38	Quantity (Units) of Fuel Burned	724948	0	0	0	1533164	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	65998	0	0	0	1028	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	94.202	2.989	0.000
41	Average Cost of Fuel per Unit Burned	63.020	0.000	0.000	0.000	2.989	0.000
42	Average Cost of Fuel Burned per Million BTU	0.955	0.000	0.000	0.000	2.909	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.032	0.000
44	Average BTU per KWh Net Generation	10086.000	0.000	0.000	0.000	11034.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Wateree* (d)	Plant Name: *McMeekin* (e)	Plant Name: *Canadys* (f)	Line No.
Steam	Steam	Steam	1
Outdoor-Boiler	Semi-Outdoor	Outdoor-Boiler	2
1970	1958	1962	3
1971	1958	1967	4
771.80	293.60	0.00	5
688	262	0	6
8297	7204	0	7
0	0	0	8
684	250	0	9
684	250	0	10
99	56	5	11
3198891000	1004061000	0	12
2119622	15668	5602944	13
136171570	24578522	0	14
763042771	191471626	0	15
-2395649	9716543	0	16
898938314	225782359	5602944	17
1164.7296	769.0135	0	18
1699763	392558	0	19
127196554	35935153	0	20
0	0	0	21
670781	1938973	0	22
0	0	0	23
0	0	0	24
2838905	834551	0	25
1961930	976676	0	26
0	1500	0	27
3273	9940	0	28
17722	18713	0	29
1456406	230806	0	30
7077441	1307605	0	31
4870769	518835	0	32
2026803	764964	0	33
149820347	42930274	0	34
0.0468	0.0428	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Coal	Gas	Oil				36
Tons	Barrels		Tons	MCF	Barrels				37
1305683	37080	0	137027	6438177	1128	0	0	0	38
12613	138297	0	12569	1030	138625	0	0	0	39
92.843	78.180	0.000	99.871	3.185	0.000	0.000	0.000	0.000	40
93.643	90.903	0.000	99.871	3.185	136.466	0.000	0.000	0.000	41
3.697	15.650	0.000	4.361	3.136	23.439	0.000	0.000	0.000	42
0.039	0.000	0.000	0.036	0.000	0.000	0.000	0.000	0.000	43
10364.000	0.000	0.000	10045.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Cope* (b)	Plant Name: *Parr #1 & 2* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Package
3	Year Originally Constructed	1996	1970
4	Year Last Unit was Installed	1996	1970
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	417.36	39.10
6	Net Peak Demand on Plant - MW (60 minutes)	420	33
7	Plant Hours Connected to Load	6649	53
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	415	34
10	When Limited by Condenser Water	415	27
11	Average Number of Employees	67	0
12	Net Generation, Exclusive of Plant Use - KWh	2199703000	716000
13	Cost of Plant: Land and Land Rights	3216902	9560
14	Structures and Improvements	82277448	363352
15	Equipment Costs	454649574	5935160
16	Asset Retirement Costs	2985597	-36356
17	Total Cost	543129521	6271716
18	Cost per KW of Installed Capacity (line 17/5) Including	1301.3454	160.4019
19	Production Expenses: Oper, Supv, & Engr	93606	0
20	Fuel	81867431	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	111611	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1827449	0
26	Misc Steam (or Nuclear) Power Expenses	2191772	0
27	Rents	0	0
28	Allowances	6051	0
29	Maintenance Supervision and Engineering	15396	0
30	Maintenance of Structures	166190	0
31	Maintenance of Boiler (or reactor) Plant	5030494	0
32	Maintenance of Electric Plant	389403	0
33	Maintenance of Misc Steam (or Nuclear) Plant	2896165	0
34	Total Production Expenses	94595568	0
35	Expenses per Net KWh	0.0430	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	814405	7245	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12517	138367	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	92.797	90.141	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	93.876	105.735	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.808	18.194	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.036	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9278.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Parr #3 & 4* (d)	Plant Name: *Parr Combined* (e)	Plant Name: *Hagood #4* (f)	Line No.
Gas Turbine		Gas Turbine	1
Package		Package	2
1971		1991	3
1971		1991	4
44.54	83.64	121.89	5
44	77	95	6
81	134	316	7
0	0	0	8
39	0	99	9
33	0	88	10
0	2	0	11
1595000	2311000	20610000	12
6291	15851	96047	13
514066	877418	3457065	14
3630875	9566035	34044289	15
-23925	-60281	-6253778	16
4127307	10399023	31343623	17
92.6652	124.3307	257.1468	18
0	53851	0	19
0	522650	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	135217	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	4215	0	30
0	0	0	31
0	76446	0	32
0	0	0	33
0	792379	0	34
0.0000	0.3429	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	23267	4811	0	0	0	0	38
0	0	0	1031	138002	0	0	0	0	39
0.000	0.000	0.000	3.780	79.195	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.780	90.502	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.667	15.614	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.057	0.565	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Hagood #5* (b)	Plant Name: *Hagood #6* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package	Package
3	Year Originally Constructed	2000	1981
4	Year Last Unit was Installed	2000	1981
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	27.40	27.94
6	Net Peak Demand on Plant - MW (60 minutes)	21	20
7	Plant Hours Connected to Load	248	124
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	21	21
10	When Limited by Condenser Water	19	20
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	3628000	1799000
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	350421	683139
15	Equipment Costs	7446893	9250140
16	Asset Retirement Costs	0	0
17	Total Cost	7797314	9933279
18	Cost per KW of Installed Capacity (line 17/5) Including	284.5735	355.5218
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: *Hagood Combined* (d)			Plant Name: *Hardeeville Peaking* (e)			Plant Name: *Urquhart #1 Peaking* (f)			Line No.
			Gas Turbine			Gas Turbine			1
			Package			Package			2
			1968			1969			3
			1968			1969			4
177.23			16.32			19.63			5
136			2			10			6
688			3			24			7
0			0			0			8
0			9			16			9
0			9			13			10
9			0			0			11
26037000			6000			121000			12
96047			5261			0			13
4490625			57556			504934			14
50741322			3553212			2248548			15
-6253778			-7592			0			16
49074216			3608437			2753482			17
276.8956			221.1052			140.2691			18
15239			433			0			19
1560518			6504			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
263420			125730			0			25
0			0			0			26
0			0			0			27
-5			0			0			28
95748			0			0			29
226898			0			0			30
0			0			0			31
90033			33809			0			32
0			0			0			33
2251851			166476			0			34
0.0865			27.7460			0.0000			35
Gas	Oil		Oil						36
MCF	Barrels		Barrels						37
280102	3712	0	55	0	0	0	0	0	38
1031	138018	0	138142	0	0	0	0	0	39
3.863	84.242	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.863	129.482	0.000	118.667	0.000	0.000	0.000	0.000	0.000	41
3.748	22.337	0.000	20.453	0.000	0.000	0.000	0.000	0.000	42
0.045	0.257	0.000	1.085	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Urquhart #2 Peaking* (b)			Plant Name: *Urquhart #3 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	16.32			16.32		
6	Net Peak Demand on Plant - MW (60 minutes)	10			10		
7	Plant Hours Connected to Load	21			25		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	17			15		
10	When Limited by Condenser Water	14			12		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	88000			121000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	400859			391033		
15	Equipment Costs	1967175			2501227		
16	Asset Retirement Costs	0			0		
17	Total Cost	2368034			2892260		
18	Cost per KW of Installed Capacity (line 17/5) Including	145.1001			177.2218		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Urquhart #4 Peaking* (d)			Plant Name: *Urquhart Comb 1-4* (e)			Plant Name: *Urquhart Comb Cycle* (f)			Line No.
Gas Turbine						Combined Cycle			1
Package						Package			2
1999						2002			3
1999						2002			4
58.90			111.17			547.80			5
46			76			458			6
405			475			10165			7
0			0			0			8
49			0			484			9
48			0			458			10
0			3			0			11
14548000			14878000			1789440000			12
0			0			0			13
642355			1939181			4752426			14
24673078			31390028			262801456			15
0			0			0			16
25315433			33329209			267553882			17
429.8036			299.8040			488.4153			18
0			59926			487238			19
0			512903			53889468			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			1387300			1373019			25
0			0			0			26
0			0			3752			27
0			-3			48			28
0			75			11150			29
0			660			342646			30
0			0			1167			31
0			650341			10773955			32
0			0			0			33
0			2611202			66882443			34
0.0000			0.1755			0.0374			35
			Gas	Oil		Gas	Oil		36
			MCF	Barrels		MCF	Barrels		37
0	0	0	151874	541	0	13763651	23983	0	38
0	0	0	1028	138151	0	1027	137558	0	39
0.000	0.000	0.000	2.942	0.000	0.000	3.715	0.000	0.000	40
0.000	0.000	0.000	2.942	104.555	0.000	3.715	117.892	0.000	41
0.000	0.000	0.000	2.925	18.147	0.000	3.619	20.417	0.000	42
0.000	0.000	0.000	0.031	0.606	0.000	0.030	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coit #1 Peaking* (b)			Plant Name: *Coit #2 Peaking* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package			Package		
3	Year Originally Constructed	1969			1969		
4	Year Last Unit was Installed	1969			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.64			19.64		
6	Net Peak Demand on Plant - MW (60 minutes)	19			18		
7	Plant Hours Connected to Load	33			28		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	18			18		
10	When Limited by Condenser Water	14			12		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	273000			175000		
13	Cost of Plant: Land and Land Rights	36498			27261		
14	Structures and Improvements	98497			83380		
15	Equipment Costs	3437967			2558035		
16	Asset Retirement Costs	-24957			-18641		
17	Total Cost	3548005			2650035		
18	Cost per KW of Installed Capacity (line 17/5) Including	180.6520			134.9305		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Coit Combined* (d)	Plant Name: *Williams #1 Peaking* (e)	Plant Name: *Williams #2 Peaking* (f)	Line No.
	Gas Turbine	Gas Turbine	1
	Package	Package	2
	1972	1972	3
	1972	1972	4
39.27	23.80	23.80	5
37	26	24	6
61	35	34	7
0	0	0	8
0	26	26	9
0	20	20	10
0	0	0	11
448000	496000	305000	12
63759	0	0	13
181877	564588	31825	14
5996002	3269692	3733593	15
-43598	0	0	16
6198040	3834280	3765418	17
157.8314	161.1042	158.2108	18
0	0	0	19
120788	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
19126	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
404	0	0	29
0	0	0	30
0	0	0	31
104641	0	0	32
0	0	0	33
244959	0	0	34
0.5468	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Oil								36
MCF	Barrels								37
3753	866	0	0	0	0	0	0	0	38
1030	138058	0	0	0	0	0	0	0	39
4.372	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
4.372	120.746	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
4.242	20.824	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.088	0.399	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Williams Combined* (b)			Plant Name: *Boeing* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Solar Photovoltaic		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)				Full-Outdoor		
3	Year Originally Constructed				2011		
4	Year Last Unit was Installed				2011		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	47.60			2.60		
6	Net Peak Demand on Plant - MW (60 minutes)	50			0		
7	Plant Hours Connected to Load	69			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	801000			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	596413			117179		
15	Equipment Costs	7003285			9245463		
16	Asset Retirement Costs	0			0		
17	Total Cost	7599698			9362642		
18	Cost per KW of Installed Capacity (line 17/5) Including	159.6575			3601.0162		
19	Production Expenses: Oper, Supv, & Engr	433			0		
20	Fuel	181689			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	157182			57		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	2			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	3923			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	85840			41724		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	429069			41781		
35	Expenses per Net KWh	0.5357			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Barrels				
38	Quantity (Units) of Fuel Burned	6236	1368	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1029	135836	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.865	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.865	115.387	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.755	20.226	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.065	0.369	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Kapstone Generator* (d)	Plant Name: *Jasper* (e)	Plant Name: *Major Maint. Accrual* (f)	Line No.
Steam	Combined Cycle		1
Outdoor - Boiler	Package		2
1999	2004		3
1999	2004		4
99.31	1001.70	0.00	5
94	945	0	6
8443	6275	0	7
0	0	0	8
85	924	0	9
85	852	0	10
0	34	0	11
543429509	5500604000	0	12
0	2737068	0	13
0	28120423	0	14
11144060	475905757	0	15
0	-14377	0	16
11144060	506748871	0	17
112.2149	505.8889	0	18
0	703436	0	19
30445765	128899580	0	20
0	0	0	21
10224441	0	0	22
0	0	0	23
0	0	0	24
0	2763983	-11320	25
0	1831	0	26
0	0	0	27
0	77	0	28
0	364677	0	29
0	6473	0	30
0	43	-766386	31
0	2630755	1840889	32
0	350	-31214	33
40670206	135371205	1031969	34
0.0748	0.0246	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas	Oil					36
			MCF	Barrels					37
0	0	0	39608700	15109	0	0	0	0	38
0	0	0	1031	139795	0	0	0	0	39
0.000	0.000	0.000	3.249	99.085	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.249	8.705	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.152	1.483	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.023	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: f

In December 2012, the Company retired the 90MW Unit 1 at Canadys Station. In November 2013, the Company retired the remaining units, Unit 2 (115MW) and Unit 3 (180MW).

Schedule Page: 402 Line No.: 1 Column: b

SCE&G's portion (two-thirds) of jointly owned plant.

Instruction No. 12 - V. C. Summer Nuclear Station

(a) Nuclear fuel amortization, which is included in Production Expenses, is recorded using the units-of-production method. Normal operation and maintenance costs are charged to expenses as incurred with appropriate application of the accrual method of accounting. Pursuant to an order issued by the South Carolina Public Service Commission, estimated refueling outage operation and maintenance costs for the five outages scheduled Spring 2014 through Spring 2020 are being accrued over the 90 month period (January 2013 through June 2020) covered by these outages.

(b) Cost is recorded for nuclear fuel on the batch basis. At reload, the number of new assemblies required to complete the core requirement of 157 assemblies is designated as the new batch. All costs for this new batch are reported according to classification of component by batch number. Each batch consists of costs for U308, conversion, enrichment, fabrication, and allowance for funds used during construction.

(c) The V. C. Summer Nuclear Station is a Westinghouse PWR Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy tube cladding. The equilibrium cycle has approximately 65.5 metric tons of Uranium metal with a nominal U-235 enrichment of 4.6% to 4.8%. The reactor is licensed to allow operation of 2900 MWt.

Schedule Page: 403 Line No.: 5 Column: f

As of December 2013, no remaining units were in service. Therefore, no installed capacity is being reported for this plant.

Schedule Page: 403 Line No.: 18 Column: f

As of December 2013 no remaining units were in service and the only remaining cost (asset value) is land. Therefore, no "cost per KW installed capacity" is being reported for this plant.

Schedule Page: 403.1 Line No.: 2 Column: e

Parr Steam Plant functions in a combined cycle operation with four gas turbine peaking units and two heat recovery boilers. Production expenses and fuel data are for the entire operation. See column (e), lines 19-44 for combined data on Parr units.

Schedule Page: 402.1 Line No.: 11 Column: c

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: d

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: e

Employees not specifically assigned to individual units.

Schedule Page: 403.1 Line No.: 11 Column: f

Employees not specifically assigned to individual units.

Schedule Page: 402.2 Line No.: 11 Column: b

Employees not specifically assigned to individual units.

Schedule Page: 402.2 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.2 Line No.: 11 Column: e
Unattended-automatic.

Schedule Page: 403.2 Line No.: 11 Column: f
Employees not specifically assigned to individual units.

Schedule Page: 402.3 Line No.: 11 Column: b
Employees not specifically assigned to individual units.

Schedule Page: 402.3 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: e
Employees not specifically assigned to individual units.

Schedule Page: 403.3 Line No.: 11 Column: f
Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: b
Employees not specifically assigned to individual units.

Schedule Page: 402.4 Line No.: 11 Column: c
Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: d
Employees not specifically assigned to individual units.

Schedule Page: 403.4 Line No.: 11 Column: e
Unattended-automatic.

Schedule Page: 403.4 Line No.: 11 Column: f
Unattended-automatic.

Schedule Page: 402.5 Line No.: -1 Column: c
This is a rooftop mounted solar electric generator that provides electricity exclusively for use by a large industrial customer. None of the output flows onto the grid.

Schedule Page: 403.5 Line No.: -1 Column: f
The major maintenance accrual represents an SCPSC approved (SCPSC Docket No. 2009-489-E) annual accrual of $18.4 million through 2017. The Company is allowed to collect $18.4 million through retail electric rates to offset expenditures relating to certain turbine maintenance. Under this mechanism, the Company records an annual expense accrual of $18.4 million and records any difference between actual expenses incurred and this accrual as a regulatory asset or liability as appropriate.

For the year ended December 31, 2015, the Company incurred actual expenses in the amount of $16.5 million for major maintenance that is subject to this accrual. Cumulative costs for turbine maintenance in excess of cumulative collections are classified as a regulatory asset on the balance sheet.

Schedule Page: 402.5 Line No.: 11 Column: b
Unattended-automatic.

Schedule Page: 403.5 Line No.: 11 Column: d
SCE&G receives shaft horsepower from Kapstone Charleston Kraft LLC, a biomass/coal cogeneration facility, to operate SCE&G's generator.

Schedule Page: 402 Line No.: 43 Column: c2
All fuels.

Schedule Page: 402 Line No.: 43 Column: d1
All fuels.

Schedule Page: 402 Line No.: 43 Column: e1
All fuels.

Schedule Page: 402 Line No.: 44 Column: c2
All fuels.

Schedule Page: 402 Line No.: 44 Column: d1
All fuels.

Schedule Page: 402 Line No.: 44 Column: e1
All fuels.

Schedule Page: 402.1 Line No.: 43 Column: b1
All fuels.

Schedule Page: 402.1 Line No.: 44 Column: b1
All fuels.

Schedule Page: 402.3 Line No.: 43 Column: f1
All fuels.

Schedule Page: 402.5 Line No.: 43 Column: e1
All fuels.

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1894 Plant Name: Parr (b)	FERC Licensed Project No. 516 Plant Name: Saluda (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1914	1930
4	Year Last Unit was Installed	1921	1971
5	Total installed cap (Gen name plate Rating in MW)	14.88	207.30
6	Net Peak Demand on Plant-Megawatts (60 minutes)	15	201
7	Plant Hours Connect to Load	8,665	8,448
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	12	200
10	(b) Under the Most Adverse Oper Conditions	7	200
11	Average Number of Employees	3	5
12	Net Generation, Exclusive of Plant Use - Kwh	48,948,000	252,783,000
13	Cost of Plant		
14	Land and Land Rights	602,632	6,161,262
15	Structures and Improvements	1,884,085	7,708,396
16	Reservoirs, Dams, and Waterways	4,721,738	354,674,527
17	Equipment Costs	5,131,976	13,325,672
18	Roads, Railroads, and Bridges	124,198	233,526
19	Asset Retirement Costs	0	-12,662
20	TOTAL cost (Total of 14 thru 19)	12,464,629	382,090,721
21	Cost per KW of Installed Capacity (line 20 / 5)	837.6767	1,843.1776
22	Production Expenses		
23	Operation Supervision and Engineering	92,772	312,051
24	Water for Power	0	0
25	Hydraulic Expenses	144,466	1,066,397
26	Electric Expenses	67,707	1,998
27	Misc Hydraulic Power Generation Expenses	94,320	170,744
28	Rents	0	0
29	Maintenance Supervision and Engineering	271	5,010
30	Maintenance of Structures	46	946
31	Maintenance of Reservoirs, Dams, and Waterways	71,996	357,320
32	Maintenance of Electric Plant	715,340	346,254
33	Maintenance of Misc Hydraulic Plant	6,603	12,685
34	Total Production Expenses (total 23 thru 33)	1,193,521	2,273,405
35	Expenses per net KWh	0.0244	0.0090

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2535 Plant Name: Stevens Creek (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1914			3
1926			4
17.28	0.00	0.00	5
18	0	0	6
8,714	0	0	7
			8
10	0	0	9
8	0	0	10
3	0	0	11
64,962,000	0	0	12
			13
406,315	0	0	14
2,909,485	0	0	15
6,430,203	0	0	16
4,553,890	0	0	17
128,812	0	0	18
-8,215	0	0	19
14,420,490	0	0	20
834.5191	0.0000	0.0000	21
			22
72,415	0	0	23
0	0	0	24
41,117	0	0	25
3,214	0	0	26
31,141	0	0	27
0	0	0	28
0	0	0	29
5,855	0	0	30
146,745	0	0	31
292,495	0	0	32
14,369	0	0	33
607,351	0	0	34
0.0093	0.0000	0.0000	35

Schedule Page: 406 Line No.: 1 Column: b

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: c

Operated under license from the Federal Energy Regulatory Commission.

Schedule Page: 406 Line No.: 1 Column: d

Operated under license from the Federal Energy Regulatory Commission.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 1984 Plant Name: Fairfield (b)
1	Type of Plant Construction (Conventional or Outdoor)	Outdoor
2	Year Originally Constructed	1978
3	Year Last Unit was Installed	1978
4	Total installed cap (Gen name plate Rating in MW)	511
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	503
6	Plant Hours Connect to Load While Generating	3,469
7	Net Plant Capability (in megawatts)	576
8	Average Number of Employees	28
9	Generation, Exclusive of Plant Use - Kwh	465,552,000
10	Energy Used for Pumping	644,211,000
11	Net Output for Load (line 9 - line 10) - Kwh	-178,659,000
12	Cost of Plant	
13	Land and Land Rights	22,147,163
14	Structures and Improvements	36,310,025
15	Reservoirs, Dams, and Waterways	74,794,684
16	Water Wheels, Turbines, and Generators	67,470,131
17	Accessory Electric Equipment	21,397,389
18	Miscellaneous Powerplant Equipment	6,267,904
19	Roads, Railroads, and Bridges	1,328,336
20	Asset Retirement Costs	-4,891
21	Total cost (total 13 thru 20)	251,106,146
22	Cost per KW of installed cap (line 21 / 4)	491.2092
23	Production Expenses	
24	Operation Supervision and Engineering	255,646
25	Water for Power	
26	Pumped Storage Expenses	126,269
27	Electric Expenses	22,841
28	Misc Pumped Storage Power generation Expenses	342,477
29	Rents	
30	Maintenance Supervision and Engineering	140,320
31	Maintenance of Structures	10
32	Maintenance of Reservoirs, Dams, and Waterways	425,514
33	Maintenance of Electric Plant	1,931,745
34	Maintenance of Misc Pumped Storage Plant	38,108
35	Production Exp Before Pumping Exp (24 thru 34)	3,282,930
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	3,282,930
38	Expenses per KWh (line 37 / 9)	0.0071

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
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			9
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			37
			38

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 408 Line No.: 38 Column: b

Required information per FERC Order No. 784, Docket No. AI14-1-000

Expenses per KWH of Generation and Pumping (Line 37/(Line 9 + Line 10)) = .0030

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro-Neal Shoals					
2	Hydro License					
3	Project #2315	1905	4.42	6.0	17,416,000	8,973,967
4						
5						
6						
7						
8						
9						
10						
11						
12						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
514	211,792		193,990			3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	115 KV System	Various	115.00	230.00	Various	104.16	15.57	
2	115 KV System	Various	115.00	115.00	Various	1,414.53	100.80	
3	46 KV System	Various	46.00	115.00	Various	42.77		
4	46 KV System	Various	46.00	46.00	Various	578.19	25.77	
5	33 KV System	Various	33.00	33.00	Various	63.59	3.29	
6	13.8 KV System	SPA	13.80	46.00	Various	0.34		1
7	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP	11.10		1
8	13.8 KV System	Neal Shoals	13.80	13.80	Wood-SP		2.90	2
9	230 KV System							
10	CEC Cola Energy	Fold-in	230.00	230.00	Steel-SP	5.88		1
11	Canadys	Sumter	230.00	230.00	Wood-H	32.00		1
12	Canadys	Faber Place #1	230.00	230.00	Wood-H	40.34		1
13	Canadys	Faber Place #2	230.00	230.00	Wood-H	42.80		1
14	Canadys	Yemassee	230.00	230.00	Wood-H	30.30		1
15	Canadys	Urquhart	230.00	230.00	Wood-H	79.47		1
16	Canadys	Graniteville-SRP	230.00	230.00	Wood-H	0.08		1
17	Canadys	Williams	230.00	230.00	Steel-SP	0.96		1
18	Church Creek	Yemassee	230.00	230.00	Various	52.10		1
19	Cope	Orangeburg	230.00	230.00	Steel-SP	22.05		2
20	Cope	Canadys	230.00	230.00	Steel-SP	40.53		2
21	Edenwood	Denny Terrace	230.00	230.00	Wood-H	12.16		1
22	Edenwood	McMeekin	230.00	230.00	Various	11.48		1
23	Edenwood	Tie	230.00	230.00	Wood-H	1.45		1
24	Edenwood	Owens Steel	230.00	230.00	Steel-SP	0.41		1
25	Fairfield	Summer	230.00	230.00	Wood-H	2.79		1
26	Goose Creek	Ashley Phos.	230.00	230.00	Wood-H	3.10		1
27	Graniteville Sub #1	Graniteville Sub #2	230.00	230.00	Steel	0.06		1
28	Graniteville	Urquhart	230.00	230.00	Wood-H	11.23		1
29	Hanahan	Bushy Park	230.00	230.00	Wood-H	10.50		1
30	Hopkins	Tap	230.00	230.00	Steel-SP	2.84		1
31	Huron	Tap	230.00	230.00	Wood-H	0.11		1
32	Jasper	Yemassee#1	230.00	230.00	Steel-SP	39.49		2
33	Jasper	Yemassee#2	230.00	230.00	Steel-SP	39.27		2
34	Jasper	Purrysburg(Santee)	230.00	230.00	Steel-SP	1.24		2
35	Ladson	Ashley Phos.	230.00	230.00	Wood-H	4.60		1
36					TOTAL	3,259.78	190.20	90

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
Various	1,307,722	15,080,941	16,388,663					1
Various	32,907,596	319,745,358	352,652,954					2
Various	393,946	2,295,765	2,689,711					3
Various	2,157,896	40,242,207	42,400,103					4
Various	62,375	3,402,878	3,465,253					5
336mcm		31,047	31,047					6
336mcm								7
336mcm	4,930	637,596	642,526					8
	14,317,367	192,718,183	207,035,550					9
1272mcm								10
795mcm								11
795mcm								12
795mcm								13
Various								14
1272mcm								15
795mcm								16
1272mcm								17
1272mcm								18
795mcm								19
795mcm								20
1272mcm								21
Various								22
1272mcm								23
1272mcm								24
1272mcm								25
1272mcm								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
1272mcm								31
1272mcm								32
1272mcm								33
1272mcm								34
795mcm								35
	70,089,567	657,568,728	727,658,295	365,391	5,313,267		5,678,658	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Lake Murray	Saluda River #1	230.00	230.00	Steel-SP	6.38		2
2	Lyles	Saluda River #1	230.00	230.00	Steel-SP	4.13		2
3	Lyles	Saluda River #2	230.00	230.00	Steel-SP	0.59		2
4	McMeekin	Parr	230.00	230.00	Wood-H	16.66		1
5	Parr	Denny Terrace	230.00	230.00	Wood-H	21.96		1
6	Parr	Duke	230.00	230.00	Tower		10.90	1
7	Pepperhill	Mateeba	230.00	230.00	Wood-H	7.10		1
8	Pineland	Denny Terrace	230.00	230.00	Steel-SP	8.46		2
9	St. George	Ladson	230.00	230.00	Wood-H	33.00		1
10	St. George	Williams	230.00	230.00	Steel-SP	0.97		1
11	Summer	Denny Terrace	230.00	230.00	Wood-H	4.53		1
12	Summer	Parr #1	230.00	230.00	Wood-H	2.38		1
13	Summer	Parr #2	230.00	230.00	Wood-H	2.26		1
14	Summer	Graniteville	230.00	230.00	Wood-H	63.26		1
15	Summer	Pineland	230.00	230.00	Wood-H	26.83		1
16	Summer	Denny Terrace	230.00	230.00	Wood-H	26.26		1
17	Summerville	Tap	230.00	230.00	Wood-H		0.08	1
18	Timberlake	Tap	230.00	230.00	Wood-SP	8.41		1
19	Urquhart	Fold-in	230.00	230.00	Steel-H	9.55		1
20	VCS1	Killian	230.00	230.00	Steel-SP	3.36		1
21	VCS1	Killian	230.00	230.00	Steel-SP	38.66		2
22	VCS2	Lake Murray #1	230.00	230.00	Steel-SP		20.53	2
23	Vogtle	SRP	230.00	230.00	Steel-H	17.10		1
24	Ward	Tie	230.00	230.00	Wood-H	0.07		1
25	Wateree	Denny Terrace	230.00	230.00	Wood-H	29.94		1
26	Wateree	Edenwood	230.00	230.00	Wood-H	27.80		1
27	Wateree	Sumter	230.00	230.00	Wood-H	0.86		1
28	Wateree	St. George	230.00	230.00	Wood-H	45.60		1
29	Wateree	Pineland	230.00	230.00	Wood-H	38.18		1
30	Wateree	Hercules	230.00	230.00	Wood-H	0.45		1
31	Wateree	Orangeburg	230.00	230.00	Wood-H	27.10		1
32	Wateree-Edenwood	Columbia	230.00	230.00	Steel-H		2.95	2
33	Williams	Wateree	230.00	230.00	Wood-H	10.30		1
34	Williams	Canadys	230.00	230.00	Wood-H	9.60	0.70	1
35	Williams	Faber Place #1	230.00	230.00	Steel-SP	0.53		2
36					TOTAL	3,259.78	190.20	90

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272mcm								1
1272mcm								2
1272mcm								3
795mcm								4
795mcm								5
954mcm								6
795mcm								7
1272mcm								8
795mcm								9
1272mcm								10
1272mcm								11
1272mcm								12
1272mcm								13
1272mcm								14
1272mcm								15
1272mcm								16
1272mcm								17
1272mcm								18
1272mcm								19
1272mcm								20
1272mcm								21
1272mcm								22
795mcm								23
1272mcm								24
Various								25
1272mcm								26
1272mcm								27
1272mcm								28
1272mcm								29
1272mcm								30
795mcm								31
1272mcm								32
1272mcm								33
1272mcm								34
1272mcm								35
	70,089,567	657,568,728	727,658,295	365,391	5,313,267		5,678,658	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Williams	Faber Place #2	230.00	230.00	Tower-H	13.65	6.71	2
2	Williams	Tie	230.00	230.00	Concrete	0.08		1
3	Williams	DuPont	230.00	230.00	Wood-H	6.60		1
4	Yemassee	Burton	230.00	230.00	Steel-SP	21.31		2
5	Yemassee	Santee	230.00	230.00	Wood-H	2.93		2
6	Underground							
7	33 KV System					0.23		2
8	46 KV System					0.90		1
9	115 KV System					19.88		1
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,259.78	190.20	90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272mcm								1
1272mcm								2
1272mcm								3
1272mcm								4
1272mcm								5
								6
250mcm		16,443	16,443					7
750mcm		1,620,606	1,620,606					8
2250kcm	18,937,735	81,777,704	100,715,439					9
				365,391	5,313,267		5,678,658	10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	70,089,567	657,568,728	727,658,295	365,391	5,313,267		5,678,658	36

Schedule Page: 422 Line No.: 1 Column: h

Various

Schedule Page: 422 Line No.: 2 Column: h

Various

Schedule Page: 422 Line No.: 3 Column: h

Various

Schedule Page: 422 Line No.: 4 Column: h

Various

Schedule Page: 422 Line No.: 5 Column: h

Various

Schedule Page: 422 Line No.: 9 Column: l

Total capitalized cost of 230 KV System.

Schedule Page: 422.2 Line No.: 10 Column: a

Reported costs in column (l) reflect total costs including balances recorded in Account 106 - Completed Construction not Classified. Columns (a) through (i) include statistical data related to unitized plant only.

Schedule Page: 422.2 Line No.: 10 Column: m

Operation expense includes Accounts 563 - Overhead Line Expenses and 564 - Underground Line Expenses.

Schedule Page: 422.2 Line No.: 10 Column: n

Maintenance expense includes Accounts 571 - Maintenance of Overhead Lines and 572 - Maintenance of Underground Lines.

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	Ultimate (g)
1	OVERHEAD:						
2	Ft. Jackson	Victory Gardens	1.28	Steel	24.00	1	1
3	Clemson Wind Turbine Tap		1.48	Steel	16.00	1	1
4	Faber Place	Hagood #1	2.42	Steel	14.00	1	2
5	North Augusta Tap		0.23	Steel	16.00	1	1
6	Hagood	Bee St.	3.07	Steel	8.00	1	1
7	Lyles	Williams St.	0.94	Wood	34.00	1	1
8	Mt. Pleasant	Osceola	1.06	Steel	9.00	1	1
9	Orangeburg East	St. George #2	11.41	Steel	38.00	2	2
10	Orangeburg East	St. George #1	2.31	Steel	44.00	1	2
11	Dunbar Rd.	Orangeburg East	5.71	Steel	13.00	1	1
12	Lake Murray	Saluda River #1	6.38	Steel	13.00	2	2
13	Lyles	Saluda River #2	0.59	Steel	5.00	2	2
14	Lyles	Saluda River #1	4.13	Steel	33.00	2	2
15	Denny Terrace	Lyles #2	5.35	N/A		1	1
16	Lyles	Saluda River #2	1.44	Steel	4.00	2	2
17	Lake Murray	Saluda River #2	3.03	Steel	2.00	2	2
18							
19	UNDERGROUND:						
20	Bayview	Charlotte St.	1.49	N/A		1	1
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		52.32		273.00	23	25

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
1272	ACSR		115		1,525,894	127,158		1,653,052	2
1272	ACSR		115	1,205,295	3,280,320			4,485,615	3
1272	ACSR		115	97,862	2,072,655	150		2,170,667	4
795	ACSR		115		242,143	143,233		385,376	5
795	ACSR		115	23,558	4,347,368	470,172		4,841,098	6
1272	ACSR		115		678,741	330,845		1,009,586	7
795	ACSR		115		1,412,944	513,454		1,926,398	8
1272	ACSR		115		1,701,654	3,649,653		5,351,307	9
1272	ACSR		115		1,331,294	723,023		2,054,317	10
1272	ACSR		115		2,166,241	1,237,093		3,403,334	11
1272	ACSR		230		2,468,522	2,103,511		4,572,033	12
1272	ACSR		230		100,208	76,608		176,816	13
1272	ACSR		230		2,309,914	485,375		2,795,289	14
1272	ACSR		115			260,286		260,286	15
1272	ACSR		115		169,077	205,382		374,459	16
1272	ACSR		115		235,694	1,265,381		1,501,075	17
									18
									19
2250	KCM		115			7,090,744		7,090,744	20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				1,326,715	24,042,669	18,682,068		44,051,452	44

Schedule Page: 424 Line No.: 15 Column: k

Design Voltage 230

Schedule Page: 424 Line No.: 16 Column: k

Design Voltage 230

Schedule Page: 424 Line No.: 17 Column: k

Design Voltage 230

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Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Aiken, Aiken County	Trans-U	115.00	46.00	
2	Aiken, Aiken County	Trans-U	115.00	12.00	
3	Barnwell, Barnwell County	Trans-U	115.00	46.00	
4	Batesburg, City of Batesburg	Trans-U	115.00	33.00	
5	Bayview, Mt. Pleasant City	Trans-U	115.00	23.00	
6	Blackville 115-46KV, Barnwell County	Trans-U	115.00	46.00	
7	Burton Transmission, Beaufort County	Trans-U	230.00	115.00	
8	Burton Transmission, Beaufort County	Trans-U	115.00	46.00	
9	Calhoun County, Calhoun County	Trans-U	115.00	46.00	
10	Calhoun Falls, Calhoun Falls City	Trans-U	115.00	46.20	
11	Calhoun Falls, Calhoun Falls City	Trans-U	43.80	13.09	
12	Callawassie, Jasper County	Trans-U	115.00	46.20	
13	Canadys Sub, Colleton County	Trans-U	230.00	115.00	
14	Charleston, Charleston County	Trans-U	115.00	24.90	
15	Church Creek, Charleston County	Trans-U	230.00	115.00	
16	Coit Gas Turbine, Richland County	Trans-U	13.80	34.50	
17	Coit, Richland County	Trans-U	115.00	24.94	
18	Coit, Richland County	Trans-U	115.00	34.64	
19	Columbia Industrial Park, Richland County	Trans-U	230.00	115.00	
20	Cope, Orangeburg County	Trans-U	230.00	115.00	
21	Cope, Orangeburg County	Trans-U	115.00	230.00	
22	Denmark, City of Denmark	Trans-U	115.00	46.20	
23	Denny Terrace, Richland County	Trans-U	230.00	115.00	
24	Edenwood, City of Cayce	Trans-U	230.00	115.00	
25	Faber Place, City of North Charleston	Trans-U	115.00	23.00	
26	Faber Place, City of North Charleston	Trans-U	230.00	115.00	
27	Fairfax, Allendale County	Trans-U	115.00	46.20	
28	Fairfield Pumped Storage, Fairfield County	Trans-U	13.80	230.00	
29	Goose Creek, Hanahan City	Trans-U	230.00	115.00	
30	Graniteville #1, Aiken County	Trans-U	115.00	46.00	
31	Graniteville #1, Aiken County	Trans-U	230.00	115.00	
32	Graniteville #2, Aiken County	Trans-U	230.00	115.00	
33	Hagood Gas Turbine, Charleston County	Trans-U	13.80	115.00	
34	Hagood Gas Turbine, Charleston County	Trans-U	13.20	115.00	
35	Hagood Gas Turbine, Charleston County	Trans-U	13.80	4.16	
36	Hamlin, Charleston County	Trans-U	115.00	25.00	
37	Hampton, Hampton County	Trans-U	115.00	46.00	
38	Hanahan, Hanahan City	Trans-U	115.00	25.00	
39	Hanahan, Hanahan City	Trans-U	115.00	46.00	
40	Hardeeville Gas Turbine, Jasper County	Trans-U	13.20	46.00	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
28	1					1
22	1					2
56	2					3
28	1					4
75	2	1				5
28	1					6
224	1					7
84	3	1				8
28	1					9
50	2	1				10
7	1					11
25	1					12
224	1	1				13
67	2					14
560	2					15
56	2					16
22	1					17
56	1					18
336	1					19
224	1					20
548	1					21
56	2					22
672	2					23
448	2					24
73	3					25
672	2	1				26
56	2					27
717	4	1				28
336	1					29
56	2					30
448	2					31
336	1					32
60	1					33
147	1					34
6	1					35
140	4					36
84	3	2				37
78	3					38
56	2					39
15	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hardeeville, Jasper County	Trans-U	115.00	46.00	
2	Hobcaw, Charleston County	Trans-U	115.00	24.94	
3	Hopkins, Richland County	Trans-U	230.00	115.00	
4	Jasper Gas Turbine, Jasper County	Trans-U	18.00	230.00	
5	Jasper Gas Turbine, Jasper County	Trans-U	21.00	230.00	
6	Kendrick, Richland County	Trans-U	115.00	24.90	
7	Kendrick, Richland County	Trans-U	115.00	35.00	
8	Killian, Richland County	Trans-U	230.00	115.00	
9	Lake Murray, Lexington County	Trans-U	230.00	115.00	
10	Lyles, Richland County	Trans-U	230.00	115.00	
11	Lyles, Richland County	Trans-U	115.00	23.00	
12	Lyles, Richland County	Trans-U	115.00	35.00	
13	McCormick, McCormick County	Trans-U	115.00	46.00	
14	McCormick, McCormick County	Trans-U	115.00	46.00	
15	McMeekin, Lexington County	Trans-U	13.80	114.00	
16	Orangeburg #1, Orangeburg County	Trans-U	115.00	46.00	
17	Orangeburg #1, Orangeburg County	Trans-U	115.00	46.00	
18	Orangeburg 230KV, Orangeburg County	Trans-U	230.00	115.00	
19	Parr Gas Turbine, Fairfield County	Trans-U	13.20	115.00	
20	Parr Hydro, Fairfield County	Trans-U	2.30	13.80	
21	Parr Steam, Fairfield County	Trans-U	115.00	13.20	
22	Pepperhill, Charleston County	Trans-U	230.00	115.00	
23	Pineland, Richland County	Trans-U	230.00	115.00	
24	Rader, Richland County	Trans-U	115.00	24.90	
25	Ridgeville, City of Ridgeville	Trans-U	115.00	46.00	
26	Ritter, Colleton County	Trans-U	230.00	115.00	
27	Saluda Hydro, Lexington County	Trans-U	13.20	115.00	
28	Saluda Hydro, Lexington County	Trans-U	115.00	23.00	
29	Saluda Hydro, Lexington County	Trans-U	115.00	13.20	
30	Saluda River, Lexington County	Trans-U	230.00	115.00	
31	Santee, Orangeburg County	Trans-U	230.00	46.20	
32	Santee, Orangeburg County	Trans-U	115.00	46.00	
33	Santee, Orangeburg County	Trans-U	230.00	115.00	
34	Savannah River, Federal Property	Trans-U	230.00	115.00	
35	St. Andrews, Charleston City	Trans-U	115.00	24.90	
36	St. George, Dorchester County	Trans-U	115.00	46.00	
37	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	2.30	46.00	
38	Stevens Creek Hydro, Columbia Cnty Ga.	Trans-U	46.00	2.30	
39	Stevens Creek Sub, Columbia Cnty Ga.	Trans-U	115.00	46.20	
40	Summerville, Berkeley County	Trans-U	230.00	115.00	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
28	1					1
28	1					2
336	1					3
700	3					4
500	1					5
56	2	1				6
56	1					7
336	1					8
672	2	1				9
336	1	1				10
56	2					11
56	1					12
28	1	1				13
30	1					14
350	2					15
25	1					16
56	2					17
672	2					18
98	2	1				19
25	3					20
34	1					21
336	1					22
672	2	1				23
45	2					24
28	1					25
336	1					26
133	3					27
65	2					28
133	2					29
336	1					30
28	1					31
28	1					32
140	1					33
672	2					34
23	1					35
28	1					36
14	2					37
14	2					38
28	1	1				39
560	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Thomas Island, Charleston County	Trans-U	115.00	24.94	
2	Trenton, Edgefield County	Trans-U	115.00	24.90	
3	Trenton, Edgefield County	Trans-U	115.00	34.60	
4	Trenton, Edgefield County	Trans-U	115.00	34.60	
5	Urquhart 115KV, Aiken County	Trans-U	115.00	13.20	
6	Urquhart 115-46KV, Aiken County	Trans-U	115.00	46.00	
7	Urquhart 230KV, Aiken County	Trans-U	18.00	230.00	
8	Urquhart Gas Turbine, Aiken County	Trans-U	13.20	115.00	
9	V. C. Summer Substation, Fairfield County	Trans-U	22.00	242.00	
10	Ward, Saluda County	Trans-U	230.00	115.00	
11	Ward, Saluda County	Trans-U	115.00	33.00	
12	Ward, Saluda County	Trans-U	115.00	33.00	
13	Wateree Plant, Richland County	Trans-U	21.00	230.00	
14	Wateree Plant, Richland County	Trans-U	230.00	13.80	
15	Williams Gas Turbine, Berkeley County	Trans-U	13.20	115.00	
16	Williams St., Columbia City	Trans-U	115.00	33.00	
17	Williams St., Columbia City	Trans-U	115.00	24.90	
18	Williams Station, Berkeley County	Trans-U	20.00	242.00	
19	Williams Station, Berkeley County	Trans-U	115.00	230.00	
20	Williams Station, Berkeley County	Trans-U	230.00	4.16	
21	Williams Station, Berkeley County	Trans-U	230.00	25.00	
22	Williston Industrial Park , Barnwell County	Trans-U	115.00	46.00	
23	Yemassee, City of Yemassee	Trans-U	230.00	115.00	
24					
25	Distribution Substations:				
26	Adams Run, Charleston County	Dist-U	115.00	24.94	
27	Adams Run, Charleston County	Dist-U	115.00	46.00	
28	Aiken #2, Aiken County	Dist-U	115.00	13.09	
29	Aiken #3, Aiken County	Dist-U	115.00	13.09	
30	Aiken Hampton Avenue, Aiken City	Dist-U	115.00	13.09	
31	Aiken Industrial Park, Aiken City	Dist-U	46.00	24.90	
32	Aiken-Steifeltown, Aiken County	Dist-U	115.00	13.09	
33	Allendale, Allendale City	Dist-U	115.00	13.09	
34	Arrowwood Road, Richland County	Dist-U	115.00	24.90	
35	Ashley Phosphate, City of North Charleston	Dist-U	115.00	24.90	
36	Bacon's Bridge, Summerville City	Dist-U	115.00	24.90	
37	Baldock, Allendale County	Dist-U	115.00	13.09	
38	Bamberg Central, Bamberg City	Dist-U	43.80	13.80	
39	Barnwell City, Barnwell City	Dist-U	46.00	13.09	
40	Barnwell Heights, Barnwell City	Dist-U	46.00	13.09	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
75	2					1
22	1	2				2
23	3					3
28	1					4
325	6	2				5
48	2					6
467	2					7
176	3					8
1232	1	1				9
140	1					10
22	1					11
28	1					12
1008	2	1				13
75	2					14
70	1					15
106	4					16
59	2					17
785	1	1				18
560	2					19
93	2					20
101	2					21
32	6					22
784	3					23
						24
						25
50	2					26
112	2					27
50	2					28
50	2					29
28	1					30
11	1					31
22	1					32
22	1					33
22	1					34
82	3					35
37	1					36
22	1					37
14	2					38
11	1					39
11	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Barnwell Industrial Park, Barnwell County	Dist-U	43.80	13.90	
2	Batesburg, Batesburg City	Dist-U	33.00	8.32	
3	Bayfront, Charleston City	Dist-U	115.00	24.90	
4	Beaufort Central, Beaufort City	Dist-U	115.00	13.09	
5	Beaufort Industrial Park, Beaufort County	Dist-U	115.00	13.09	
6	Bee Street, Charleston County	Dist-U	115.00	14.40	
7	Beech Island, Aiken County	Dist-U	46.00	15.00	
8	Bell Wright, Berkeley County	Dist-U	115.00	25.00	
9	Belmont, Richland County	Dist-U	115.00	24.90	
10	Belvedere, North Augusta City	Dist-U	115.00	13.09	
11	Blackville 46-12KV, Barnwell County	Dist-U	46.00	13.09	
12	Bluffton, Beaufort County	Dist-U	115.00	25.00	
13	Blythewood, Richland County	Dist-U	115.00	24.90	
14	Boney Rd. , Fairfield County	Dist-U	115.00	23.00	
15	Boney Rd. , Fairfield County	Dist-U	115.00	24.90	
16	Boone Hill, Dorchester County	Dist-U	115.00	24.90	
17	Bowman, Orangeburg County	Dist-U	115.00	8.73	
18	Brookwood, West Columbia City	Dist-U	115.00	24.90	
19	Burton Central, Beaufort County	Dist-U	115.00	13.09	
20	CAE Industrial Park, Lexington County	Dist-U	115.00	24.90	
21	Cainhoy Temp., Charleston County	Dist-U	115.00	24.90	
22	Calhoun Street, Columbia City	Dist-U	115.00	8.32	
23	Callawassie Island, Jasper County	Dist-U	115.00	23.00	
24	Carlisle, Carlisle City	Dist-U	115.00	23.00	
25	Center Sub, Aiken County	Dist-U	43.80	24.90	
26	Charleston Airport, N Charleston City	Dist-U	115.00	24.90	
27	Charlotte Street, Charleston City	Dist-U	115.00	14.40	
28	Church Creek, Charleston City	Dist-U	115.00	24.90	
29	Circle Drive, Richland County	Dist-U	115.00	8.72	
30	Clearwater, Aiken County	Dist-U	115.00	13.09	
31	Cloverleaf, Aiken County	Dist-U	115.00	13.09	
32	Colonial Heights, Richland County	Dist-U	115.00	24.90	
33	Columbia Airport, Springdale City	Dist-U	115.00	24.90	
34	Columbia Industrial Park, Richland County	Dist-U	115.00	24.90	
35	Congaree Creek, Cayce City	Dist-U	115.00	23.00	
36	Congaree Vista, Richland County	Dist-U	115.00	24.90	
37	Coosaw, Charleston County	Dist-U	115.00	25.00	
38	Cromer Rd, Lexington County	Dist-U	115.00	23.00	
39	Deer Park, Charleston County	Dist-U	115.00	24.94	
40	Denmark Industrial Park, Denmark City	Dist-U	46.00	13.09	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
11	1					2
40	1					3
28	1					4
22	1					5
202	4					6
11	1					7
28	1					8
50	2					9
50	2					10
11	1					11
56	2					12
77	2					13
23	1					14
22	1					15
60	2					16
11	1					17
28	1					18
56	2					19
28	1					20
56	2					21
22	1					22
28	1	1				23
13	4	1				24
11	1					25
40	1					26
101	4					27
75	2					28
22	1					29
28	1					30
22	1					31
22	1					32
22	1					33
40	1					34
28	1					35
37	1					36
37	1					37
37	1					38
45	2					39
11	1	1				40

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Dentsville, Richland County	Dist-U	115.00	24.90	
2	Dixiana, Lexington County	Dist-U	115.00	24.90	
3	East Columbia, Richland County	Dist-U	115.00	24.90	
4	Edmund, Lexington County	Dist-U	115.00	24.90	
5	Estill Southside, Estill City	Dist-U	46.00	12.00	
6	Estill, Estill City	Dist-U	46.00	13.00	
7	Eutawville, Orangeburg County	Dist-U	115.00	24.90	
8	Fairfax Central, Fairfax City	Dist-U	46.00	13.09	
9	Five Points, Columbia City	Dist-U	115.00	8.75	
10	Fort Johnston Road, Charleston County	Dist-U	115.00	24.00	
11	Frogmore, Beaufort County	Dist-U	115.00	25.00	
12	Gardens Corner, Beaufort County	Dist-U	115.00	24.90	
13	Gaston, Lexington County	Dist-U	115.00	24.94	
14	Gilbert, Lexington County	Dist-U	115.00	24.94	
15	Grays Hill, Beaufort County	Dist-U	115.00	13.00	
16	Greengate, Richland County	Dist-U	115.00	24.94	
17	Grove Street, Charleston City	Dist-U	115.00	14.40	
18	Hampton, Hampton City	Dist-U	46.00	13.09	
19	Hanahan Switching, Berkeley County	Dist-U	46.00	4.16	
20	Harbison, Lexington County	Dist-U	115.00	24.94	
21	Hardeeville, Hardeeville City	Dist-U	115.00	24.90	
22	Hardeeville, Hardeeville City	Dist-U	43.80	13.09	
23	Herrin, Allendale County	Dist-U	46.00	13.09	
24	Holly Hill, Holly Hill City	Dist-U	115.00	24.94	
25	Houndslake, Aiken County	Dist-U	115.00	13.09	
26	Howard Street, Richland County	Dist-U	33.00	8.72	
27	Irmo Town, Irmo City	Dist-U	115.00	24.90	
28	Isle of Palms, Isle of Palms City	Dist-U	115.00	24.90	
29	Jackson 46-12kV, Aiken County	Dist-U	46.00	12.00	
30	Jackson Street, Columbia City	Dist-U	115.00	8.72	
31	James Island, Charleston County	Dist-U	115.00	24.90	
32	James Prioleau, Charleston County	Dist-U	115.00	25.00	
33	Jasper Construction, Jasper County	Dist-U	115.00	33.00	
34	Johnston 115-23KV, Edgefield County	Dist-U	115.00	24.90	
35	Kilbourne Park, Richland County	Dist-U	115.00	24.90	
36	Killian, Richland County	Dist-U	115.00	23.00	
37	Kingswood, Richland County	Dist-U	115.00	24.90	
38	Kronotex, Barnwell County	Dist-U	115.00	12.00	
39	Ladies Island, Beaufort County	Dist-U	115.00	24.90	
40	Lake Carolina, Richland County	Dist-U	115.00	25.00	

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	2					1
65	2	1				2
28	1					3
22	1					4
14	1	1				5
14	1					6
50	2					7
18	2					8
22	1					9
50	2					10
28	1					11
22	1					12
50	2					13
22	1					14
22	1					15
37	1					16
22	1					17
18	2					18
14	2	1				19
50	2					20
28	1					21
21	2					22
11	1					23
50	4					24
28	1	1				25
11	1					26
56	2					27
50	2					28
11	1					29
22	1					30
45	2					31
28	1					32
11	1					33
22	1					34
60	2					35
37	1					36
45	2					37
28	1					38
50	2					39
65	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lake Murray Training, Lexington County	Dist-U	115.00	24.90	
2	Langley, Aiken County	Dist-U	115.00	13.09	
3	Laurel Bay 115-12KV, Beaufort County	Dist-U	115.00	12.00	
4	Leesville 115-23KV, Lexington County	Dist-U	115.00	24.90	
5	Lexington East Side, Lexington County	Dist-U	115.00	24.90	
6	Lexington Industrial Park, Lexington County	Dist-U	115.00	24.90	
7	Lexington West Side, Lexington County	Dist-U	115.00	23.90	
8	Lexington, Lexington County	Dist-U	115.00	23.00	
9	Lower Richland, Richland County	Dist-U	115.00	24.90	
10	Maryville, Charleston County	Dist-U	115.00	24.90	
11	McCormick City 115-13KV, McCormick Cnty	Dist-U	115.00	13.09	
12	Meadowbrook, Beaufort County	Dist-U	115.00	24.90	
13	Meeting Street, Charleston County	Dist-U	115.00	14.40	
14	Middleburg Mall, Richland County	Dist-U	115.00	8.72	
15	Midway, Union County	Dist-U	115.00	13.20	
16	Mt Pleasant, Charleston County	Dist-U	115.00	24.90	
17	Muller Avenue, Richland County	Dist-U	115.00	8.70	
18	Muller Avenue, Richland County	Dist-U	115.00	24.90	
19	Naval Shipyard, Federal Property, SC	Dist-U	115.00	24.90	
20	Naval Shipyard, Federal Property, SC	Dist-U	115.00	13.80	
21	Neeses, Orangeburg County	Dist-U	46.00	8.70	
22	Network, Richland County	Dist-U	115.00	13.80	
23	North 46-8kV, Orangeburg County	Dist-U	46.00	8.00	
24	North Augusta, Aiken City	Dist-U	115.00	13.09	
25	North Bridge Terrace, Charleston County	Dist-U	115.00	24.94	
26	North Naval Weapons, Federal Property	Dist-U	115.00	13.80	
27	North Rhett, North Charleston City	Dist-U	115.00	24.90	
28	Northpointe Business Park, Charleston County	Dist-U	115.00	23.00	
29	Northwoods Mall, North Charleston City	Dist-U	230.00	24.94	
30	Okatie, Jasper County	Dist-U	115.00	24.90	
31	Old Fort, Dorchester County	Dist-U	115.00	24.90	
32	Osceola Park, Charleston County	Dist-U	115.00	24.94	
33	Palmetto Commerce Park, Charleston City	Dist-U	115.00	24.90	
34	Park Street, Columbia City	Dist-U	33.00	13.20	
35	Parr 13.2-23KV, Fairfield County	Dist-U	24.90	13.80	
36	Pelion, Lexington County	Dist-U	115.00	24.90	
37	Pendleton Street, Columbia City	Dist-U	115.00	8.32	
38	Piney Woods Road, Richland County	Dist-U	115.00	24.94	
39	Platt Springs Rd., Lexington County	Dist-U	115.00	24.90	
40	Platt Springs Rd., Lexington County	Dist-U	115.00	24.90	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
22	1					1
22	1					2
28	1					3
28	1					4
37	1					5
60	2	1				6
75	2	1				7
65	2	1				8
60	2					9
37	1					10
11	1	1				11
22	1	1				12
22	1					13
22	1					14
21	1					15
77	2					16
22	1					17
28	1					18
28	1					19
22	1					20
11	1					21
67	3					22
11	1					23
28	1					24
45	2					25
11	1					26
28	1					27
37	1					28
75	2	1				29
28	1					30
60	2					31
37	1					32
65	2					33
45	5					34
22	1					35
22	1	1				36
45	2					37
22	1					38
28	1					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Pontiac, Richland County	Dist-U	230.00	24.94	
2	Port Park, Hanahan City	Dist-U	115.00	24.94	
3	Port Royal, Port Royal City	Dist-U	115.00	13.09	
4	Pritchardville, Beaufort County	Dist-U	115.00	24.90	
5	Quail Hollow, Lexington County	Dist-U	115.00	24.94	
6	Raborn Pointe, North Augusta City	Dist-U	115.00	13.09	
7	Rantowles, Charleston County	Dist-U	115.00	24.90	
8	Red House Rd, Charleston County	Dist-U	43.80	24.90	
9	Richland Mall, Forest Acres City	Dist-U	115.00	8.32	
10	Ridgeland, Jasper County	Dist-U	115.00	24.90	
11	Riverland Terrace, Charleston County	Dist-U	115.00	24.90	
12	Riverland Terrace, Charleston County	Dist-U	24.90	4.16	
13	Rosewood, Columbia City	Dist-U	33.00	8.30	
14	S. C. Research Association, Richland County	Dist-U	115.00	24.90	
15	Sage Mill Ind Park, Aiken County	Dist-U	115.00	13.09	
16	Saluda County, Saluda County	Dist-U	115.00	24.94	
17	Sandhill, Richland County	Dist-U	115.00	24.94	
18	Santee, Orangeburg County	Dist-U	46.00	8.70	
19	Savage Road, Charleston County	Dist-U	115.00	24.90	
20	Saxe Gotha Industrial Park, Lexington County	Dist-U	115.00	23.00	
21	Seven Mile, North Charleston City	Dist-U	115.00	24.90	
22	Shell Point, Beaufort County	Dist-U	43.80	13.09	
23	Silver Bluff Rd, Aiken County	Dist-U	115.00	13.09	
24	S-Lubeca, Richland County	Dist-U	115.00	12.00	
25	South Main, Columbia City	Dist-U	115.00	8.72	
26	Sparkleberry, Richland County	Dist-U	115.00	24.94	
27	Sparkleberry, Richland County	Dist-U	115.00	37.30	
28	Springdale, Lexington County	Dist-U	115.00	24.94	
29	St. George, Dorchester County	Dist-U	115.00	13.09	
30	St. Helena Island, Beaufort County	Dist-U	115.00	24.94	
31	St. Matthews, Calhoun County	Dist-U	43.80	24.94	
32	Stono Park, Charleston City	Dist-U	115.00	24.94	
33	Summer Construction, Fairfield County	Dist-U	115.00	24.94	
34	Summerville Central, Berkeley County	Dist-U	115.00	24.94	
35	Summerville Industrial Park, Dorchester County	Dist-U	115.00	24.94	
36	Summerville Plaza, City of Summerville	Dist-U	115.00	24.94	
37	Summerville-Ladson, Charleston County	Dist-U	115.00	24.94	
38	Swansea, Lexington County	Dist-U	46.00	23.00	
39	Sweetwater, Aiken County	Dist-U	115.00	13.09	
40	Ten Mile, Charleston County	Dist-U	115.00	24.90	

Name of Respondent South Carolina Electric & Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
75	2					1
22	1					2
28	1					3
37	1	1				4
37	1	2				5
22	1					6
28	1					7
45	2	1				8
45	2					9
22	1	1				10
22	1					11
4	1					12
21	2					13
22	1					14
28	1					15
22	1					16
75	2					17
11	1					18
45	2					19
37	1					20
22	1					21
25	2	1				22
22	1					23
22	1					24
22	1					25
38	1					26
37	1					27
45	2	1				28
28	1					29
50	2					30
23	2	1				31
37	1					32
22	1					33
40	1					34
50	2					35
37	1					36
60	2					37
11	1	1				38
22	1					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Terminal, Richland County	Dist-U	33.00	8.72	
2	Timberlake, Lexington County	Dist-U	230.00	24.94	
3	Uptown, Columbia City	Dist-U	115.00	24.90	
4	Uptown, Columbia City	Dist-U	115.00	8.72	
5	Varnville, Varnville City	Dist-U	46.00	13.09	
6	Victory Gardens, Columbia City	Dist-U	115.00	8.32	
7	Wagener, Wagnener City	Dist-U	46.00	8.32	
8	Walterboro 115-23KV, Walterboro City	Dist-U	115.00	24.90	
9	Walterboro Forest Hill, Walterboro City	Dist-U	115.00	24.94	
10	Walterboro Ind Park, Walterboro City	Dist-U	115.00	24.94	
11	Walterboro Southside, Walterboro City	Dist-U	115.00	24.94	
12	West Columbia, West Columbia City	Dist-U	33.00	8.32	
13	White Gables, Dorchester County	Dist-U	115.00	25.00	
14	White Rock, Richland County	Dist-U	115.00	24.90	
15	Whitehall, Lexington County	Dist-U	115.00	24.90	
16	Williston, Williston City	Dist-U	115.00	13.09	
17	Winnsboro, Winnsboro City	Dist-U	115.00	24.90	
18	Woodfield Park, Richland County	Dist-U	115.00	24.94	
19	Yemassee Central, Yemassee City	Dist-U	115.00	24.90	
20					
21	Distribution Substations				
22	Under 10,000 KVA (37)	Dist-U			
23					
24	FUNCTIONAL SUMMARY OF CAPACITY				
25	Transmission Substations				
26	Distribution Substations				
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
37	1	1				2
37	1	1				3
23	1					4
11	1					5
22	1					6
11	1					7
22	1					8
40	1					9
28	1					10
22	1					11
18	2					12
37	1					13
50	2	1				14
22	1					15
22	1					16
45	2					17
45	2					18
22	1					19
						20
6584						21
206						22
						23
						24
21560						25
6790						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.7 Line No.: 22 Column: c

Various

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Natural Gas Transportation and Demand	CGT	803/547	3,350,584
3	Natural Gas Commodity and Demand	SEMI	803/547	128,468,057
4	Refined Coal Purchases	Canadys Refined Coal, LLC	419	94,223,085
5	Building & Land Purchased	CGT	118/119/426.5	7,113,015
6	Assets Purchased	SCI	118/101/408.1	903,669
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Rental Fee for Use of Assets	SCANA Services	454/493	5,718,348
22	Coal Sales	Canadys Refined Coal, LLC	419	93,720,013
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
South Carolina Electric & Gas Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column: b

See page 102 for abbreviations used for Affiliated Companies.

Schedule Page: 429 Line No.: 4 Column: b

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and selling of refined coal to reduce emissions.

Schedule Page: 429 Line No.: 8 Column: a

The transactions below represent activities billed by SCANA Services, Inc. to SCE&G during the reporting period.

REPORTING BUSINESS UNIT	Category	FERC Account	Direct	Allocated	Total Billed
SCEG	Corporate Security	1070	110,846	31,929	142,775
SCEG	Corporate Security	1080	378,306	0	378,306
SCEG	Corporate Security	1180	14,780	3,813	18,593
SCEG	Corporate Security	1210	4,127	0	4,127
SCEG	Corporate Security	1823	54,379	0	54,379
SCEG	Corporate Security	1860	1,384	24,018	25,402
SCEG	Corporate Security	4081	201,783	11,679	213,462
SCEG	Corporate Security	4082	1,252	0	1,252
SCEG	Corporate Security	4171	5,066	0	5,066
SCEG	Corporate Security	4210	0	2,713	2,713
SCEG	Corporate Security	4265	102,797	4,020	106,817
SCEG	Corporate Security	5240	102	0	102
SCEG	Corporate Security	5490	177	0	177
SCEG	Corporate Security	9040	(1,917)	0	(1,917)
SCEG	Corporate Security	9050	441	0	441
SCEG	Corporate Security	9200	2,852,853	168,825	3,021,678
SCEG	Corporate Security	9210	667,552	20,315	687,867
SCEG	Corporate Security	9230	3,843,385	311,193	4,154,578
SCEG	Corporate Security	9250	158	0	158
SCEG	Corporate Security	9260	729,835	170,962	900,797
SCEG	Corporate Security	9310	33,690	0	33,690
SCEG	Corporate Security	9350	8,277	0	8,277
SCEG	Customer Services & Operational Support	1070	1,371,190	161,488	1,532,678
SCEG	Customer Services & Operational Support	1180	880,495	19,286	899,781
SCEG	Customer Services & Operational Support	1630	2,916	0	2,916
SCEG	Customer Services & Operational Support	1823	36,108	0	36,108
SCEG	Customer Services & Operational Support	1840	365,678	0	365,678
SCEG	Customer Services & Operational Support	1860	(124)	121,475	121,351
SCEG	Customer Services & Operational Support	4081	947,639	80,533	1,028,172
SCEG	Customer Services & Operational Support	4082	970	1,376	2,346
SCEG	Customer Services & Operational Support	4160	57,436	14,898	72,334
SCEG	Customer Services & Operational Support	4171	7,550	5,266	12,816
SCEG	Customer Services & Operational Support	4210	0	13,721	13,721
SCEG	Customer Services & Operational Support	4261	1,624	2,502	4,126
SCEG	Customer Services & Operational Support	4265	19,995	4,905	24,900

SCEG	Customer Services & Operational Support	5370	3,975	0	3,975
SCEG	Customer Services & Operational Support	5617	7,346	0	7,346
SCEG	Customer Services & Operational Support	5800	50,872	0	50,872
SCEG	Customer Services & Operational Support	5880	415,613	0	415,613
SCEG	Customer Services & Operational Support	5930	177,326	0	177,326
SCEG	Customer Services & Operational Support	8560	11	0	11
SCEG	Customer Services & Operational Support	8610	0	518	518
SCEG	Customer Services & Operational Support	8700	1,332	277	1,609
SCEG	Customer Services & Operational Support	8740	129,553	1,696	131,249
SCEG	Customer Services & Operational Support	8800	0	117	117
SCEG	Customer Services & Operational Support	8850	244	0	244
SCEG	Customer Services & Operational Support	9010	1,173,670	57	1,173,727
SCEG	Customer Services & Operational Support	9020	32,233	0	32,233
SCEG	Customer Services & Operational Support	9030	15,100,999	1,124,379	16,225,378
SCEG	Customer Services & Operational Support	9050	2,018,792	17,569	2,036,361
SCEG	Customer Services & Operational Support	9080	94,850	0	94,850
SCEG	Customer Services & Operational Support	9120	1,153	0	1,153
SCEG	Customer Services & Operational Support	9200	1,196,085	55,073	1,251,158
SCEG	Customer Services & Operational Support	9210	721,463	8,843	730,306
SCEG	Customer Services & Operational Support	9230	(2,390)	0	(2,390)
SCEG	Customer Services & Operational Support	9260	3,346,085	938,567	4,284,652
SCEG	Customer Services & Operational Support	9302	1,129	0	1,129
SCEG	Customer Services & Operational Support	9310	10,047	29,970	40,017
SCEG	Customer Services & Operational Support	9350	111,951	1,270	113,221
SCEG	Employee Services	1070	2,958,326	1,107,904	4,066,230
SCEG	Employee Services	1080	314	0	314
SCEG	Employee Services	1180	3,811,878	121,810	3,933,688
SCEG	Employee Services	1190	21,658	0	21,658
SCEG	Employee Services	1540	18,659	0	18,659
SCEG	Employee Services	1630	680	0	680
SCEG	Employee Services	1823	29,542	0	29,542
SCEG	Employee Services	1840	73,278	0	73,278
SCEG	Employee Services	1860	116,073	53,975	170,048
SCEG	Employee Services	4081	937,999	251,314	1,189,313
SCEG	Employee Services	4082	1,250	13,679	14,929
SCEG	Employee Services	4160	4,414	1,519	5,933
SCEG	Employee Services	4171	5,166	46,482	51,648
SCEG	Employee Services	4210	0	6,097	6,097
SCEG	Employee Services	4261	0	4,531	4,531
SCEG	Employee Services	4264	0	9,598	9,598
SCEG	Employee Services	4265	41,926	994,430	1,036,356
SCEG	Employee Services	5000	436	0	436
SCEG	Employee Services	5060	313	0	313
SCEG	Employee Services	5120	1,015	0	1,015
SCEG	Employee Services	5170	576	0	576

SCEG	Employee Services	5200	6,062	0	6,062
SCEG	Employee Services	5240	153,952	0	153,952
SCEG	Employee Services	5350	758	0	758
SCEG	Employee Services	5370	3,150	0	3,150
SCEG	Employee Services	5380	787	0	787
SCEG	Employee Services	5390	3,766	0	3,766
SCEG	Employee Services	5440	25	0	25
SCEG	Employee Services	5480	25	0	25
SCEG	Employee Services	5490	110	0	110
SCEG	Employee Services	5530	135	0	135
SCEG	Employee Services	5560	52	0	52
SCEG	Employee Services	5600	25	0	25
SCEG	Employee Services	5620	34	0	34
SCEG	Employee Services	5660	366	0	366
SCEG	Employee Services	5692	25	0	25
SCEG	Employee Services	5700	405	0	405
SCEG	Employee Services	5710	923	0	923
SCEG	Employee Services	5800	489	0	489
SCEG	Employee Services	5820	172	0	172
SCEG	Employee Services	5830	1,481	0	1,481
SCEG	Employee Services	5850	115	0	115
SCEG	Employee Services	5880	35,023	0	35,023
SCEG	Employee Services	5920	3,916	0	3,916
SCEG	Employee Services	5930	263	0	263
SCEG	Employee Services	8700	91,030	983	92,013
SCEG	Employee Services	8740	75,065	45,240	120,305
SCEG	Employee Services	8790	45	0	45
SCEG	Employee Services	8800	11,112	0	11,112
SCEG	Employee Services	8850	9	0	9
SCEG	Employee Services	8870	111,876	0	111,876
SCEG	Employee Services	9030	312,040	0	312,040
SCEG	Employee Services	9050	12,630	0	12,630
SCEG	Employee Services	9070	50	0	50
SCEG	Employee Services	9080	7,962	0	7,962
SCEG	Employee Services	9100	309,996	0	309,996
SCEG	Employee Services	9120	2,416	0	2,416
SCEG	Employee Services	9160	76	0	76
SCEG	Employee Services	9200	22,492,762	2,742,291	25,235,053
SCEG	Employee Services	9210	271,283	623,483	894,766
SCEG	Employee Services	9230	3,106	435,817	438,923
SCEG	Employee Services	9250	901,264	76,336	977,600
SCEG	Employee Services	9260	1,042,254	1,074,800	2,117,054
SCEG	Employee Services	9302	287	59,712	59,999
SCEG	Employee Services	9310	10,135	515,757	525,892
SCEG	Employee Services	9320	0	0	0

SCEG	Employee Services	9350	5,749	28,614	34,363
SCEG	Environmental Services	1070	118,569	25,963	144,532
SCEG	Environmental Services	1080	245,368	0	245,368
SCEG	Environmental Services	1180	65,758	3,101	68,859
SCEG	Environmental Services	1190	323	0	323
SCEG	Environmental Services	1210	1,015	0	1,015
SCEG	Environmental Services	1840	81,404	0	81,404
SCEG	Environmental Services	1860	24,115	19,530	43,645
SCEG	Environmental Services	4081	132,654	22,854	155,508
SCEG	Environmental Services	4082	4,910	0	4,910
SCEG	Environmental Services	4171	16,795	0	16,795
SCEG	Environmental Services	4210	0	2,206	2,206
SCEG	Environmental Services	4261	12,864	196	13,060
SCEG	Environmental Services	4265	20,383	24,975	45,358
SCEG	Environmental Services	5000	116	0	116
SCEG	Environmental Services	5060	3,118	0	3,118
SCEG	Environmental Services	5240	1,559	0	1,559
SCEG	Environmental Services	5390	3,118	0	3,118
SCEG	Environmental Services	5490	520	0	520
SCEG	Environmental Services	5660	25,466	0	25,466
SCEG	Environmental Services	5880	15,072	0	15,072
SCEG	Environmental Services	5920	259,119	0	259,119
SCEG	Environmental Services	7350	1,853,558	0	1,853,558
SCEG	Environmental Services	9100	9	0	9
SCEG	Environmental Services	9200	1,406,204	326,272	1,732,476
SCEG	Environmental Services	9210	215,558	73,528	289,086
SCEG	Environmental Services	9230	907,498	215,094	1,122,592
SCEG	Environmental Services	9260	494,665	190,089	684,754
SCEG	Environmental Services	9302	54,556	0	54,556
SCEG	Environmental Services	9310	1,622	0	1,622
SCEG	Environmental Services	9320	206	0	206
SCEG	Environmental Services	9350	349,696	0	349,696
SCEG	Executive Services	1070	1,627,571	37,121	1,664,692
SCEG	Executive Services	1180	0	4,433	4,433
SCEG	Executive Services	1210	25,376	0	25,376
SCEG	Executive Services	1823	434	0	434
SCEG	Executive Services	1840	358,966	0	358,966
SCEG	Executive Services	1860	705	27,924	28,629
SCEG	Executive Services	4081	71,812	106,363	178,175
SCEG	Executive Services	4082	1,784	17,877	19,661
SCEG	Executive Services	4171	6,458	66,603	73,061
SCEG	Executive Services	4210	0	3,154	3,154
SCEG	Executive Services	4261	0	37,030	37,030
SCEG	Executive Services	4264	109,101	0	109,101
SCEG	Executive Services	4265	157,717	657,670	815,387

SCEG	Executive Services	5170	64,316	0	64,316
SCEG	Executive Services	5240	19,315	0	19,315
SCEG	Executive Services	5280	342	0	342
SCEG	Executive Services	5660	67,875	0	67,875
SCEG	Executive Services	5800	133	0	133
SCEG	Executive Services	5880	5,147	0	5,147
SCEG	Executive Services	5930	30,381	0	30,381
SCEG	Executive Services	9050	27	0	27
SCEG	Executive Services	9200	840,647	1,380,887	2,221,534
SCEG	Executive Services	9210	25,206	84,088	109,294
SCEG	Executive Services	9230	0	152,227	152,227
SCEG	Executive Services	9260	269,943	503,912	773,855
SCEG	Executive Services	9280	1,044	0	1,044
SCEG	Executive Services	9302	829,806	0	829,806
SCEG	Executive Services	9310	0	3,093	3,093
SCEG	Executive Services	9350	3,720	0	3,720
SCEG	Financial Services	1070	12,764,292	400,150	13,164,442
SCEG	Financial Services	1080	46	0	46
SCEG	Financial Services	1180	3,873,731	43,548	3,917,279
SCEG	Financial Services	1823	1,751,862	0	1,751,862
SCEG	Financial Services	1840	70,873	0	70,873
SCEG	Financial Services	1860	160,939	72,684	233,623
SCEG	Financial Services	4081	279,590	4,142,948	4,422,538
SCEG	Financial Services	4082	8,822	9,342	18,164
SCEG	Financial Services	4140	0	10,892,304	10,892,304
SCEG	Financial Services	4160	3,839	238,537	242,376
SCEG	Financial Services	4171	9,111	5,509	14,620
SCEG	Financial Services	4210	0	8,210	8,210
SCEG	Financial Services	4264	2,822	800	3,622
SCEG	Financial Services	4265	115,994	(52,646)	63,348
SCEG	Financial Services	4300	0	6,443,328	6,443,328
SCEG	Financial Services	4320	0	(8,086)	(8,086)
SCEG	Financial Services	5240	(18,670)	0	(18,670)
SCEG	Financial Services	5560	88,154	0	88,154
SCEG	Financial Services	5617	(2,462)	0	(2,462)
SCEG	Financial Services	5660	(1,712)	0	(1,712)
SCEG	Financial Services	5880	(1,907)	0	(1,907)
SCEG	Financial Services	5920	(251,186)	0	(251,186)
SCEG	Financial Services	7350	(1,501,112)	0	(1,501,112)
SCEG	Financial Services	8760	(3,707)	0	(3,707)
SCEG	Financial Services	9030	329,760	59,097	388,857
SCEG	Financial Services	9050	242	0	242
SCEG	Financial Services	9080	94	0	94
SCEG	Financial Services	9120	(1,567)	0	(1,567)
SCEG	Financial Services	9200	3,491,294	(98,418)	3,392,876

SCEG	Financial Services	9210	(1,270,531)	1,333,545	63,014
SCEG	Financial Services	9230	2,713,277	2,172,527	4,885,804
SCEG	Financial Services	9240	(390,961)	338,448	(52,513)
SCEG	Financial Services	9250	1,469,717	7,081	1,476,798
SCEG	Financial Services	9260	1,149,028	1,071,437	2,220,465
SCEG	Financial Services	9280	925	0	925
SCEG	Financial Services	9302	0	292,613	292,613
SCEG	Financial Services	9310	3,612,146	698,774	4,310,920
SCEG	Financial Services	9350	519,528	173,460	692,988
SCEG	Gas Control Coordination & Gas Engineering Services	1070	1,264	15,235	16,499
SCEG	Gas Control Coordination & Gas Engineering Services	1180	427,486	1,820	429,306
SCEG	Gas Control Coordination & Gas Engineering Services	1823	2,307,784	0	2,307,784
SCEG	Gas Control Coordination & Gas Engineering Services	1860	19,301	11,460	30,761
SCEG	Gas Control Coordination & Gas Engineering Services	4081	39,810	45,113	84,923
SCEG	Gas Control Coordination & Gas Engineering Services	4210	0	1,294	1,294
SCEG	Gas Control Coordination & Gas Engineering Services	4265	0	52	52
SCEG	Gas Control Coordination & Gas Engineering Services	8400	110,776	(338)	110,438
SCEG	Gas Control Coordination & Gas Engineering Services	8410	1,882	278	2,160
SCEG	Gas Control Coordination & Gas Engineering Services	8432	16,390	91	16,481
SCEG	Gas Control Coordination & Gas Engineering Services	8510	0	716	716
SCEG	Gas Control Coordination & Gas Engineering Services	8610	636	28,613	29,249
SCEG	Gas Control Coordination & Gas Engineering Services	8630	6	0	6
SCEG	Gas Control Coordination & Gas Engineering Services	8700	358,402	242,723	601,125
SCEG	Gas Control Coordination & Gas Engineering Services	8740	63,730	359,789	423,519
SCEG	Gas Control Coordination & Gas Engineering Services	8760	0	123	123
SCEG	Gas Control Coordination & Gas Engineering Services	8800	27,549	1,297	28,846
SCEG	Gas Control Coordination & Gas Engineering Services	8850	8,059	634	8,693
SCEG	Gas Control Coordination & Gas Engineering Services	8870	499,292	67	499,359
SCEG	Gas Control Coordination & Gas Engineering Services	9090	5,525	0	5,525
SCEG	Gas Control Coordination & Gas Engineering Services	9100	251,835	158	251,993
SCEG	Gas Control Coordination & Gas Engineering Services	9120	1,379	3,884	5,263
SCEG	Gas Control Coordination & Gas Engineering Services	9200	221,324	58,479	279,803
SCEG	Gas Control Coordination & Gas Engineering Services	9210	6,063	110,153	116,216
SCEG	Gas Control Coordination & Gas Engineering Services	9230	472	1,274	1,746
SCEG	Gas Control Coordination & Gas Engineering Services	9260	148,785	226,981	375,766
SCEG	Gas Control Coordination & Gas Engineering Services	9302	138,800	0	138,800
SCEG	Gas Measurement Services	1070	0	4,639	4,639
SCEG	Gas Measurement Services	1180	1,203,405	554	1,203,959
SCEG	Gas Measurement Services	1630	83,373	0	83,373
SCEG	Gas Measurement Services	1860	0	3,489	3,489
SCEG	Gas Measurement Services	4081	8,113	4,854	12,967
SCEG	Gas Measurement Services	4210	0	394	394
SCEG	Gas Measurement Services	8620	0	112	112
SCEG	Gas Measurement Services	8700	26,831	6,387	33,218
SCEG	Gas Measurement Services	8740	0	128	128

SCEG	Gas Measurement Services	8750	0	741	741
SCEG	Gas Measurement Services	8760	429	0	429
SCEG	Gas Measurement Services	8780	0	95	95
SCEG	Gas Measurement Services	8800	25,561	4,017	29,578
SCEG	Gas Measurement Services	8900	137	0	137
SCEG	Gas Measurement Services	8930	70,673	39,496	110,169
SCEG	Gas Measurement Services	9200	3,695	63,454	67,149
SCEG	Gas Measurement Services	9210	(31,754)	1,533	(30,221)
SCEG	Gas Measurement Services	9230	0	1,681	1,681
SCEG	Gas Measurement Services	9260	27,349	36,434	63,783
SCEG	Gas Measurement Services	9310	0	275,189	275,189
SCEG	Gas Measurement Services	9350	542	0	542
SCEG	Gas Supply and Fuel Procurement	1070	0	7,457	7,457
SCEG	Gas Supply and Fuel Procurement	1180	0	891	891
SCEG	Gas Supply and Fuel Procurement	1860	0	5,609	5,609
SCEG	Gas Supply and Fuel Procurement	4081	33,295	17,822	51,117
SCEG	Gas Supply and Fuel Procurement	4210	0	634	634
SCEG	Gas Supply and Fuel Procurement	4265	60	4,373	4,433
SCEG	Gas Supply and Fuel Procurement	5240	17,041	0	17,041
SCEG	Gas Supply and Fuel Procurement	9200	456,431	252,932	709,363
SCEG	Gas Supply and Fuel Procurement	9210	42,858	185,215	228,073
SCEG	Gas Supply and Fuel Procurement	9260	125,110	93,723	218,833
SCEG	Information Services	1070	13,178,895	682,757	13,861,652
SCEG	Information Services	1080	17,740	0	17,740
SCEG	Information Services	1180	952,935	69,449	1,022,384
SCEG	Information Services	1210	1,151,833	0	1,151,833
SCEG	Information Services	1630	178,629	0	178,629
SCEG	Information Services	1822	7,854	0	7,854
SCEG	Information Services	1823	1,653,729	0	1,653,729
SCEG	Information Services	1840	393,506	0	393,506
SCEG	Information Services	1860	269,243	27,644	296,887
SCEG	Information Services	2270	(1,097,353)	0	(1,097,353)
SCEG	Information Services	2430	(54,480)	0	(54,480)
SCEG	Information Services	4081	93,000	2,219	95,219
SCEG	Information Services	4082	10,942	0	10,942
SCEG	Information Services	4140	0	134,398	134,398
SCEG	Information Services	4160	3,694	163,226	166,920
SCEG	Information Services	4171	347,968	0	347,968
SCEG	Information Services	4210	0	3,123	3,123
SCEG	Information Services	4261	518	11,514	12,032
SCEG	Information Services	4264	134	2,215	2,349
SCEG	Information Services	4265	290,661	63,147	353,808
SCEG	Information Services	5000	10,243	0	10,243
SCEG	Information Services	5010	10,008	0	10,008
SCEG	Information Services	5060	617,194	0	617,194

SCEG	Information Services	5170	13,453	0	13,453
SCEG	Information Services	5190	57,659	0	57,659
SCEG	Information Services	5200	326,998	0	326,998
SCEG	Information Services	5240	5,355,861	0	5,355,861
SCEG	Information Services	5280	1,294	0	1,294
SCEG	Information Services	5290	29,158	0	29,158
SCEG	Information Services	5300	2,548	0	2,548
SCEG	Information Services	5320	1,309,131	0	1,309,131
SCEG	Information Services	5350	9,277	0	9,277
SCEG	Information Services	5370	13,425	0	13,425
SCEG	Information Services	5380	1,681	0	1,681
SCEG	Information Services	5390	138,497	0	138,497
SCEG	Information Services	5440	464	0	464
SCEG	Information Services	5460	6,323	0	6,323
SCEG	Information Services	5480	856	0	856
SCEG	Information Services	5490	110,391	0	110,391
SCEG	Information Services	5560	172,012	0	172,012
SCEG	Information Services	5600	24,561	0	24,561
SCEG	Information Services	5611	7,382	0	7,382
SCEG	Information Services	5612	46,595	0	46,595
SCEG	Information Services	5620	185,562	0	185,562
SCEG	Information Services	5630	1,071	0	1,071
SCEG	Information Services	5660	231,842	0	231,842
SCEG	Information Services	5680	23,243	0	23,243
SCEG	Information Services	5700	191,101	0	191,101
SCEG	Information Services	5710	6,529	0	6,529
SCEG	Information Services	5730	190,908	0	190,908
SCEG	Information Services	5800	3,132	0	3,132
SCEG	Information Services	5810	2,199	0	2,199
SCEG	Information Services	5820	137,519	0	137,519
SCEG	Information Services	5830	10,920	0	10,920
SCEG	Information Services	5860	8,736	0	8,736
SCEG	Information Services	5880	1,025,639	0	1,025,639
SCEG	Information Services	5900	697	0	697
SCEG	Information Services	5920	49,721	0	49,721
SCEG	Information Services	5930	78,926	0	78,926
SCEG	Information Services	5940	46,103	0	46,103
SCEG	Information Services	5950	881	0	881
SCEG	Information Services	5960	7,663	0	7,663
SCEG	Information Services	5970	60,278	0	60,278
SCEG	Information Services	5980	2,304	0	2,304
SCEG	Information Services	8400	224	0	224
SCEG	Information Services	8410	12,262	0	12,262
SCEG	Information Services	8439	14,112	0	14,112
SCEG	Information Services	8700	20,662	0	20,662

SCEG	Information Services	8710	4,899	0	4,899
SCEG	Information Services	8740	116,185	0	116,185
SCEG	Information Services	8750	52,880	0	52,880
SCEG	Information Services	8760	83,943	0	83,943
SCEG	Information Services	8780	26,560	0	26,560
SCEG	Information Services	8790	27,408	0	27,408
SCEG	Information Services	8800	337,953	0	337,953
SCEG	Information Services	8870	4,936	0	4,936
SCEG	Information Services	8900	664	0	664
SCEG	Information Services	8920	5,703	0	5,703
SCEG	Information Services	8930	11,049	0	11,049
SCEG	Information Services	8940	727	0	727
SCEG	Information Services	9010	31,091	0	31,091
SCEG	Information Services	9020	445,524	202,680	648,204
SCEG	Information Services	9030	16,983,113	164,169	17,147,282
SCEG	Information Services	9050	615,808	0	615,808
SCEG	Information Services	9070	2,280	0	2,280
SCEG	Information Services	9080	161,259	0	161,259
SCEG	Information Services	9100	9,244	0	9,244
SCEG	Information Services	9110	5,057	0	5,057
SCEG	Information Services	9120	176,168	0	176,168
SCEG	Information Services	9160	(1,725)	380,364	378,639
SCEG	Information Services	9200	972,370	31,285	1,003,655
SCEG	Information Services	9210	12,987,758	2,099,614	15,087,372
SCEG	Information Services	9230	802	0	802
SCEG	Information Services	9260	331,501	154,626	486,127
SCEG	Information Services	9302	223,282	8,372	231,654
SCEG	Information Services	9310	597,191	35,169	632,360
SCEG	Information Services	9350	1,609,615	0	1,609,615
SCEG	Land & Facilities Management	1070	4,752,078	58,147	4,810,225
SCEG	Land & Facilities Management	1080	3,022,953	0	3,022,953
SCEG	Land & Facilities Management	1180	480,638	6,505	487,143
SCEG	Land & Facilities Management	1190	(3,429,052)	0	(3,429,052)
SCEG	Land & Facilities Management	1210	981,667	0	981,667
SCEG	Land & Facilities Management	1630	17,350	0	17,350
SCEG	Land & Facilities Management	1823	62	0	62
SCEG	Land & Facilities Management	1840	123,299	0	123,299
SCEG	Land & Facilities Management	1860	221,908	11,161	233,069
SCEG	Land & Facilities Management	4081	54,249	35,583	89,832
SCEG	Land & Facilities Management	4082	12,907	4,958	17,865
SCEG	Land & Facilities Management	4171	39,951	18,787	58,738
SCEG	Land & Facilities Management	4210	0	1,261	1,261
SCEG	Land & Facilities Management	4261	9,398	0	9,398
SCEG	Land & Facilities Management	4265	422,257	83,700	505,957
SCEG	Land & Facilities Management	5000	15	0	15

SCEG	Land & Facilities Management	5010	1,025,266	0	1,025,266
SCEG	Land & Facilities Management	5060	58,785	0	58,785
SCEG	Land & Facilities Management	5110	56,443	0	56,443
SCEG	Land & Facilities Management	5120	174,594	0	174,594
SCEG	Land & Facilities Management	5140	37,300	0	37,300
SCEG	Land & Facilities Management	5170	12,690	0	12,690
SCEG	Land & Facilities Management	5240	38,611	0	38,611
SCEG	Land & Facilities Management	5290	565,024	0	565,024
SCEG	Land & Facilities Management	5300	12,335	0	12,335
SCEG	Land & Facilities Management	5320	29,571	0	29,571
SCEG	Land & Facilities Management	5350	0	0	0
SCEG	Land & Facilities Management	5370	8,107	0	8,107
SCEG	Land & Facilities Management	5390	32,756	0	32,756
SCEG	Land & Facilities Management	5420	1,093	0	1,093
SCEG	Land & Facilities Management	5430	85,499	0	85,499
SCEG	Land & Facilities Management	5440	3,043	0	3,043
SCEG	Land & Facilities Management	5450	4,496	0	4,496
SCEG	Land & Facilities Management	5460	7,146	0	7,146
SCEG	Land & Facilities Management	5490	53,108	0	53,108
SCEG	Land & Facilities Management	5520	7,228	0	7,228
SCEG	Land & Facilities Management	5530	1,676	0	1,676
SCEG	Land & Facilities Management	5560	56,112	0	56,112
SCEG	Land & Facilities Management	5660	(40,630)	0	(40,630)
SCEG	Land & Facilities Management	5690	15,376	0	15,376
SCEG	Land & Facilities Management	5692	3,614	0	3,614
SCEG	Land & Facilities Management	5700	61,409	0	61,409
SCEG	Land & Facilities Management	5800	5,472	0	5,472
SCEG	Land & Facilities Management	5830	201	0	201
SCEG	Land & Facilities Management	5850	28	0	28
SCEG	Land & Facilities Management	5860	3,114	0	3,114
SCEG	Land & Facilities Management	5880	46,486	0	46,486
SCEG	Land & Facilities Management	5890	338,411	0	338,411
SCEG	Land & Facilities Management	5900	1,160	0	1,160
SCEG	Land & Facilities Management	5910	311	0	311
SCEG	Land & Facilities Management	5920	144,223	0	144,223
SCEG	Land & Facilities Management	5930	8,654	0	8,654
SCEG	Land & Facilities Management	5940	1,027	0	1,027
SCEG	Land & Facilities Management	5970	(1,694)	0	(1,694)
SCEG	Land & Facilities Management	5980	5,928	0	5,928
SCEG	Land & Facilities Management	8410	518	0	518
SCEG	Land & Facilities Management	8432	22,429	0	22,429
SCEG	Land & Facilities Management	8439	11,461	0	11,461
SCEG	Land & Facilities Management	8750	8,436	0	8,436
SCEG	Land & Facilities Management	8810	119,339	0	119,339
SCEG	Land & Facilities Management	8870	683	0	683

SCEG	Land & Facilities Management	8890	1,418	0	1,418
SCEG	Land & Facilities Management	9020	7,894	0	7,894
SCEG	Land & Facilities Management	9030	4,473	0	4,473
SCEG	Land & Facilities Management	9050	1,584	0	1,584
SCEG	Land & Facilities Management	9080	6,951	0	6,951
SCEG	Land & Facilities Management	9120	17,642	0	17,642
SCEG	Land & Facilities Management	9200	2,388	0	2,388
SCEG	Land & Facilities Management	9210	98,697	24,434	123,131
SCEG	Land & Facilities Management	9260	122,445	182,181	304,626
SCEG	Land & Facilities Management	9302	1,728	0	1,728
SCEG	Land & Facilities Management	9310	112,443	9,253	121,696
SCEG	Land & Facilities Management	9320	1,118	0	1,118
SCEG	Land & Facilities Management	9350	2,722,007	2,106,916	4,828,923
SCEG	Legal	1070	2,104,689	43,302	2,147,991
SCEG	Legal	1080	(299)	0	(299)
SCEG	Legal	1180	48,812	5,172	53,984
SCEG	Legal	1190	441	0	441
SCEG	Legal	1210	3,201	0	3,201
SCEG	Legal	1823	117,910	0	117,910
SCEG	Legal	1830	8,342	0	8,342
SCEG	Legal	1860	137,960	32,573	170,533
SCEG	Legal	4081	131,839	150,161	282,000
SCEG	Legal	4082	365	167	532
SCEG	Legal	4160	18,808	0	18,808
SCEG	Legal	4171	1,366	708	2,074
SCEG	Legal	4210	0	3,679	3,679
SCEG	Legal	4261	13,552	0	13,552
SCEG	Legal	4265	54,406	150,780	205,186
SCEG	Legal	5240	76	0	76
SCEG	Legal	5390	157	0	157
SCEG	Legal	5617	33,003	0	33,003
SCEG	Legal	7350	15,193	0	15,193
SCEG	Legal	8740	2,050	0	2,050
SCEG	Legal	9030	(112)	0	(112)
SCEG	Legal	9080	1,272	0	1,272
SCEG	Legal	9120	1,532	0	1,532
SCEG	Legal	9200	1,484,510	2,029,514	3,514,024
SCEG	Legal	9210	(62,227)	119,296	57,069
SCEG	Legal	9230	4,287,028	1,498,941	5,785,969
SCEG	Legal	9250	2,185,258	67,027	2,252,285
SCEG	Legal	9260	486,454	640,578	1,127,032
SCEG	Legal	9280	219,381	0	219,381
SCEG	Legal	9302	0	1,547,392	1,547,392
SCEG	Legal	9350	358	0	358
SCEG	Marketing & Sales	1070	15,310	24,110	39,420

SCEG	Marketing & Sales	118	0	2,879	2,879
SCEG	Marketing & Sales	1823	231,423	0	231,423
SCEG	Marketing & Sales	1860	0	18,136	18,136
SCEG	Marketing & Sales	4081	51,120	41,476	92,596
SCEG	Marketing & Sales	4082	65,472	1,962	67,434
SCEG	Marketing & Sales	4150	0	0	0
SCEG	Marketing & Sales	4160	3,699,324	43,438	3,742,762
SCEG	Marketing & Sales	4171	241,528	7,531	249,059
SCEG	Marketing & Sales	4210	0	2,049	2,049
SCEG	Marketing & Sales	4265	1,603,409	36,805	1,640,214
SCEG	Marketing & Sales	5660	924	0	924
SCEG	Marketing & Sales	5930	92	0	92
SCEG	Marketing & Sales	9110	5,934	0	5,934
SCEG	Marketing & Sales	9120	219,957	2,016	221,973
SCEG	Marketing & Sales	9130	(5,547)	2,179	(3,368)
SCEG	Marketing & Sales	9160	206,858	0	206,858
SCEG	Marketing & Sales	9200	313,720	577,346	891,066
SCEG	Marketing & Sales	9210	164,938	119,761	284,699
SCEG	Marketing & Sales	9230	0	16,180	16,180
SCEG	Marketing & Sales	9260	191,452	241,539	432,991
SCEG	Marketing & Sales	9302	74,758	50,530	125,288
SCEG	Marketing & Sales	9310	770	730	1,500
SCEG	Procurement	1070	815,939	26,795	842,734
SCEG	Procurement	1080	6,503	0	6,503
SCEG	Procurement	1180	329,183	3,200	332,383
SCEG	Procurement	1630	348,566	0	348,566
SCEG	Procurement	1860	0	20,156	20,156
SCEG	Procurement	4081	94,298	6,489	100,787
SCEG	Procurement	4082	11	138	149
SCEG	Procurement	4171	41	562	603
SCEG	Procurement	4210	0	2,277	2,277
SCEG	Procurement	4265	21,446	4,217	25,663
SCEG	Procurement	8790	(298)	0	(298)
SCEG	Procurement	9200	1,325,771	90,926	1,416,697
SCEG	Procurement	9210	139,193	4,414	143,607
SCEG	Procurement	9230	14,095	250	14,345
SCEG	Procurement	9260	352,294	130,564	482,858
SCEG	Procurement	9302	46,135	0	46,135
SCEG	Procurement	9310	5,850	0	5,850
SCEG	Procurement	9350	0	0	0
SCEG	Public Affairs	1070	390,458	26,788	417,246
SCEG	Public Affairs	1180	0	3,199	3,199
SCEG	Public Affairs	1823	1,582	0	1,582
SCEG	Public Affairs	1860	2,010	20,151	22,161
SCEG	Public Affairs	4081	62,675	28,174	90,849

SCEG	Public Affairs	4082	52,981	32,371	85,352
SCEG	Public Affairs	4171	200,020	122,607	322,627
SCEG	Public Affairs	4210	0	2,276	2,276
SCEG	Public Affairs	4261	4,382,613	73,511	4,456,124
SCEG	Public Affairs	4264	1,971,051	508,489	2,479,540
SCEG	Public Affairs	4265	900,855	414,806	1,315,661
SCEG	Public Affairs	9200	865,880	373,286	1,239,166
SCEG	Public Affairs	9210	319,305	237,005	556,310
SCEG	Public Affairs	9230	70,362	0	70,362
SCEG	Public Affairs	9260	232,994	190,608	423,602
SCEG	Public Affairs	9280	3,400	0	3,400
SCEG	Public Affairs	9302	(24,575)	0	(24,575)
SCEG	Public Affairs	9310	2,045	12,100	14,145
SCEG	Public Affairs	9350	0	86	86
SCEG	Regulatory	1070	414,136	12,892	427,028
SCEG	Regulatory	1180	0	1,540	1,540
SCEG	Regulatory	1823	113,191	0	113,191
SCEG	Regulatory	1860	0	9,698	9,698
SCEG	Regulatory	4081	83,164	663	83,827
SCEG	Regulatory	4082	0	176	176
SCEG	Regulatory	4171	0	648	648
SCEG	Regulatory	4210	0	1,095	1,095
SCEG	Regulatory	4265	274	3,767	4,041
SCEG	Regulatory	9200	846,569	19,218	865,787
SCEG	Regulatory	9210	29,532	1,071	30,603
SCEG	Regulatory	9230	74,005	0	74,005
SCEG	Regulatory	9260	313,042	53,780	366,822
SCEG	Regulatory	9280	437,816	0	437,816
SCEG	Regulatory	9310	6,045	0	6,045
SCEG	Regulatory	9350	0	249	249
SCEG	Strategic Planning	1070	233,323	23,820	257,143
SCEG	Strategic Planning	1180	583	2,845	3,428
SCEG	Strategic Planning	1860	0	17,918	17,918
SCEG	Strategic Planning	4081	109,175	37,619	146,794
SCEG	Strategic Planning	4082	1,004	772	1,776
SCEG	Strategic Planning	4171	4,007	2,568	6,575
SCEG	Strategic Planning	4210	0	2,024	2,024
SCEG	Strategic Planning	4265	18,155	23,811	41,966
SCEG	Strategic Planning	9200	1,552,148	537,872	2,090,020
SCEG	Strategic Planning	9210	226,907	79,511	306,418
SCEG	Strategic Planning	9260	410,242	232,834	643,076
SCEG	Strategic Planning	9280	3,181	0	3,181
SCEG	Strategic Planning	9302	1,541,280	0	1,541,280
SCEG	Strategic Planning	9310	6,465	0	6,465
	Grand Total		232,116,351	63,579,406	295,695,757

Incentive compensation costs are included in the Employee Services category.

The Financial Services category includes depreciation, property taxes, accrued payroll and other costs recorded at a corporate level by SCANA Services, Inc.

Allocated costs billed from SCANA Services, Inc. are billed using one of the approved methodologies described below.

1. Information Systems Charge-back Rates - Rates for services, including but not limited to Software, Consulting, Mainframe, Midtier and Network Connectivity Services, are based on the costs of labor, materials and Information Services overheads related to the provision of each service. Such rates are applied based on the specific equipment employed and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

2. Margin Revenue Ratio - "Margin" is equal to the excess of sales revenues over the applicable cost of sales, i.e., cost of fuel for generation and gas for resale. The numerator is equal to margin revenues for a specific Client Entity and the denominator is equal to the combined margin revenues of all the applicable Client Entities. This ratio is evaluated annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, based on results of operations for a subsequent twelve-month period, as may be required due to significant changes.

3. Number of Customers Ratio - A ratio based on the number of customers served by each subsidiary or operating unit. This ratio is determined annually based on actual number of customers and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

4. Number of Employees Ratio - A ratio based on the number of employees benefiting from the performance of a service. This ratio is determined annually based on actual counts of applicable employees and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

5. Three-Factor Formula - This formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues and may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes.

6. Modified Three-Factor Method - A ratio for the allocation of non-directly assigned corporate governance costs. The Modified Three-Factor Method provides for an allocation of costs to the principal holding company; the Three-Factor Method does not. The formula is determined annually based on the average of gross property, payroll charges (salaries and wages, including overtime, shift premium and holiday pay, but not including pension, benefit and company paid payroll taxes) and gross revenues. For the purpose of the Modified Three-Factor Method, the dividends resulting from operations of the subsidiaries are used as a proxy for revenues for the principal holding company.

7. Telecommunications Charge-back Rates - Rates for use of telecommunications services other than those encompassed by Information Systems Charge-back Rates are based on the costs of labor, materials, outside services and Telecommunications overheads. Such rates are applied based on the specific equipment employment and the measured usage of services by Client Entities. These rates are determined annually based on actual experience and may be adjusted for any known and reasonably quantifiable events, or at such time as may

be required due to significant changes.

8. Gas Sales Ratio - A ratio based on the actual number of dekatherms of natural gas sold by the applicable gas distribution or marketing operations. This ratio is determined annually based on actual results of operations and may be adjusted for any known and reasonably quantifiable events, or at such time, as may be required due to significant changes.

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Amount based on measured usage of assets to include computer resource usage, margin revenues, three-factor formula, number of customers and number of employees.

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SCE&G
Response to 1-28

	Expensed						Capitalized/Balance Sheet Accounts								Totals		
	Regular Time O&M	Overtime O&M	Regular Time BTL	Overtime BTL	Total Regular Time	Total Overtime	Regular Time CWIP	Overtime CWIP	Regular Time RWIP	Overtime RWIP	Regular Time Other Deferred	Overtime Other Deferred	Total Regular Time	Total Overtime	Total Expensed	Total Balance Sheet	Grand Total
Twelve Months Ended December 2014	185,000,182	17,690,280	3,959,646	67,950	188,959,828	17,758,230	80,817,953	3,922,498	5,589,533	503,188	3,050,621	158,644	89,458,107	4,584,330	206,718,058	94,042,437	300,760,495
Twelve Months Ended December 2015	183,071,155	16,754,753	4,200,104	75,687	187,271,259	16,830,440	89,230,731	5,085,037	6,525,565	452,166	3,388,007	50,507	99,144,303	5,587,710	204,101,699	104,732,013	308,833,712
Twelve Months Ended December 2016	188,488,218	13,723,346	4,258,917	51,330	192,747,135	13,774,676	93,657,314	4,786,975	5,357,535	395,965	5,305,341	2,890,046	104,320,190	8,072,986	206,521,811	112,393,176	318,914,987
Twelve Months Ended September 2017	193,186,892	17,642,723	4,112,964	42,400	197,299,856	17,685,123	96,688,458	5,480,715	4,976,663	457,062	6,525,657	2,904,943	108,190,778	8,842,720	214,984,979	117,033,498	332,018,477

South Carolina Electric & Gas Company

Office of Regulatory Staff's Continuing Audit Information Request

Docket No. 2017-307-E (2nd Continuing AIR)

Docket No. 2017-305-E (1st Continuing AIR)

Docket No. 2017-370-E (1st Continuing AIR)

Response 1-31

Line No	Account	2013	2014	% Incr(Decr)	2015	% Incr(Decr)	2016	% Incr(Decr)
1	1. POWER PRODUCTION EXPENSES							
2	A. Steam Power Generation							
3	Operation							
4	(500) Operation Supervision and Engineering	2,743,994	2,161,090	-21.2%	2,419,201	11.9%	2,542,754	5.1%
5	(501) Fuel	327,682,689	354,576,791	8.2%	280,051,019	-21.0%	241,232,166	-13.9%
6	(502) Steam Expenses	23,732,305	16,116,564	-32.1%	13,218,658	-18.0%	16,631,366	25.8%
7	(503) Steam from Other Sources							
8	(Less) (504) Steam Transferred-Cr.							
9	(505) Electric Expenses	10,617,335	5,374,910	-49.4%	5,537,786	3.0%	6,020,395	8.7%
10	(506) Miscellaneous Steam Power Expenses	4,863,649	5,610,284	15.4%	6,232,820	11.1%	5,762,431	-7.5%
11	(507) Rents	17,160	9,977	-41.9%	1,500	-85.0%	4,500	200.0%
12	(509) Allowances	630,573	280,940	-55.4%	19,389	-93.1%	(137,732)	-810.4%
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	370,287,705	384,130,556	3.7%	307,480,373	-20.0%	272,055,880	-11.5%
14	Maintenance							
15	(510) Maintenance Supervision and Engineering	422,919	79,209	-81.3%	85,716	8.2%	91,613	6.9%
16	(511) Maintenance of Structures	1,646,229	1,160,209	-29.5%	1,862,262	60.5%	1,361,389	-26.9%
17	(512) Maintenance of Boiler Plant	11,446,285	13,050,710	14.0%	12,896,627	-1.2%	12,333,379	-4.4%
18	(513) Maintenance of Electric Plant	11,745,211	11,863,967	1.0%	12,615,664	6.3%	11,543,547	-8.5%
19	(514) Maintenance of Miscellaneous Steam Plant	4,312,698	4,724,110	9.5%	6,265,718	32.6%	4,513,165	-28.0%
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	29,573,342	30,878,205	4.4%	33,725,987	9.2%	29,843,093	-11.5%
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	399,861,047	415,008,761	3.8%	341,206,360	-17.8%	301,898,973	-11.5%
22	B. Nuclear Power Generation							
23	Operation							
24	(517) Operation Supervision and Engineering	10,875,158	9,291,240	-14.6%	9,399,979	1.2%	12,421,296	32.1%
25	(518) Fuel	62,366,870	46,626,853	-25.2%	45,687,791	-2.0%	56,467,219	23.6%
26	(519) Coolants and Water	2,129,426	2,790,759	31.1%	3,149,217	12.8%	2,876,256	-8.7%
27	(520) Steam Expenses	4,855,977	8,079,790	66.4%	7,326,705	-9.3%	6,316,647	-13.8%
28	(521) Steam from Other Sources							
29	(Less) (522) Steam Transferred-Cr.							
30	(523) Electric Expenses	1,261,395	2,759,022	118.7%	2,359,644	-14.5%	1,566,158	-33.6%
31	(524) Miscellaneous Nuclear Power Expenses	37,495,273	37,745,367	0.7%	37,477,684	-0.7%	41,091,216	9.6%
32	(525) Rents							
33	TOTAL Operation (Enter Total of lines 24 thru 32)	118,984,099	107,293,031	-9.8%	105,401,020	-1.8%	120,738,792	14.6%
34	Maintenance							
35	(528) Maintenance Supervision and Engineering	15,766,158	(6,444,574)	-140.9%	(3,055,152)	-52.6%	15,200,712	-597.5%
36	(529) Maintenance of Structures	2,433,899	3,944,397	62.1%	3,106,875	-21.2%	2,738,627	-11.9%
37	(530) Maintenance of Reactor Plant Equipment	2,476,037	17,174,412	593.6%	14,474,420	-15.7%	3,069,010	-78.8%
38	(531) Maintenance of Electric Plant	2,156,886	3,572,623	65.6%	3,416,419	-4.4%	2,500,132	-26.8%
39	(532) Maintenance of Miscellaneous Nuclear Plant	9,268,012	17,763,933	91.7%	17,185,353	-3.3%	10,319,397	-40.0%
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	32,100,992	36,010,791	12.2%	35,127,915	-2.5%	33,827,878	-3.7%
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	151,085,091	143,303,822	-5.2%	140,528,935	-1.9%	154,566,670	10.0%
42	C. Hydraulic Power Generation							
43	Operation							
44	(535) Operation Supervision and Engineering	684,140	790,193	15.5%	770,952	-2.4%	702,170	-8.9%
45	(536) Water for Power							
46	(537) Hydraulic Expenses	1,298,361	1,380,176	6.3%	1,398,001	1.3%	1,286,134	-8.0%
47	(538) Electric Expenses	152,107	178,574	17.4%	162,263	-9.1%	181,718	12.0%
48	(539) Miscellaneous Hydraulic Power Generation Expenses	677,877	656,211	-3.2%	726,151	10.7%	1,089,500	50.0%
49	(540) Rents							
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	2,812,485	3,005,154	6.9%	3,057,367	1.7%	3,259,522	6.6%
51	C. Hydraulic Power Generation (Continued)							
52	Maintenance							
53	(541) Mainentance Supervision and Engineering	102,598	136,004	32.6%	145,819	7.2%	152,188	4.4%
54	(542) Maintenance of Structures	59,702	162,777	172.6%	7,785	-95.2%	18,362	135.9%
55	(543) Maintenance of Reservoirs, Dams, and Waterways	518,202	905,926	74.8%	1,034,426	14.2%	702,406	-32.1%
56	(544) Maintenance of Electric Plant	2,928,739	2,520,808	-13.9%	3,441,143	36.5%	3,104,540	-9.8%
57	(545) Maintenance of Miscellaneous Hydraulic Plant	109,338	129,992	18.9%	76,450	-41.2%	110,419	44.4%
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,718,579	3,855,507	3.7%	4,705,623	22.0%	4,087,915	-13.1%
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	6,531,064	6,860,661	5.0%	7,762,990	13.2%	7,347,437	-5.4%
60	D. Other Power Generation							
61	Operation							
62	(546) Operation Supervision and Engineering	1,075,547	1,041,855	-3.1%	1,146,657	10.1%	1,100,946	-4.0%
63	(547) Fuel	207,735,329	247,487,163	19.1%	185,680,047	-25.0%	165,339,292	-11.0%
64	(548) Generation Expenses	4,285,430	4,298,392	0.3%	4,757,331	10.7%	5,023,761	5.6%
65	(549) Miscellaneous Other Power Generation Expenses	1,552,639	1,943,589	25.2%	1,617,315	-16.8%	1,554,627	-3.9%
66	(550) Rents	-	2,473		43,752	1669.2%	40,800	-6.7%
67	TOTAL Operation (Enter Total of lines 62 thru 66)	214,648,945	254,773,472	18.7%	193,245,102	-24.2%	173,059,426	-10.4%
68	Maintenance							
69	(551) Maintenance Supervision and Engineering	466,766	468,415	0.4%	469,644	0.3%	345,076	-26.5%
70	(552) Maintenance of Structures	561,344	542,199	-3.4%	584,816	7.9%	553,263	-5.4%
71	(553) Maintenance of Generating and Electric Plant	11,743,209	11,977,720	2.0%	11,824,623	-1.3%	13,764,550	16.4%
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	418,540	749,383	79.0%	654,807	-12.6%	663,459	1.3%
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	13,189,859	13,737,717	4.2%	13,533,890	-1.5%	15,326,348	13.2%
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	227,838,804	268,511,189	17.9%	206,778,992	-23.0%	188,385,774	-8.9%
75	E. Other Power Supply Expenses							
76	(555) Purchased Power	270,958,797	311,058,580	14.8%	282,221,548	-9.3%	254,194,400	-9.9%
77	(556) System Control and Load Dispatching	1,956,470	2,201,882	12.5%	2,937,877	33.4%	2,718,759	-7.5%
78	(557) Other Expenses	483,467	382,158	-21.0%	267,004	-30.1%	263,750	-1.2%
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	273,398,734	313,642,620	14.7%	285,426,429	-9.0%	257,176,909	-9.9%

Line No	Account	2013	2014	% Incr(Decr)	2015	% Incr(Decr)	2016	% Incr(Decr)
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	###########	###########	8.4%	981,703,706	-14.4%	909,375,763	-7.4%
81	2. TRANSMISSION EXPENSES							
82	Operation							
83	(560) Operation Supervision and Engineering	754,720	905,055	19.9%	851,568	-5.9%	792,884	-6.9%
84	(561) Load Dispatching							
85	(561.1) Load Dispatch-Reliability	1,159,932	1,264,086	9.0%	1,038,723	-17.8%	1,076,009	3.6%
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	745,511	876,821	17.6%	599,016	-31.7%	773,525	29.1%
87	(561.3) Load Dispatch-Transmission Service and Scheduling	212,760	211,643	-0.5%	186,478	-11.9%	169,113	-9.3%
88	(561.4) Scheduling, System Control and Dispatch Services							
89	(561.5) Reliability, Planning and Standards Development	74,649	99,185	32.9%	48,676	-50.9%	45,352	-6.8%
90	(561.6) Transmission Service Studies	(4,618)	(244)	-94.7%	8,136	-3434.4%	3,905	-52.0%
91	(561.7) Generation Interconnection Studies	1,475	19,809	1243.0%	(191,571)	-1067.1%	(196,944)	2.8%
92	(561.8) Reliability, Planning and Standards Development Services							
93	(562) Station Expenses	381,189	395,129	3.7%	452,676	14.6%	437,299	-3.4%
94	(563) Overhead Lines Expenses	1,390,266	380,296	-72.6%	365,391	-3.9%	51,577	-85.9%
95	(564) Underground Lines Expenses							
96	(565) Transmission of Electricity by Others	541,357	3,177,500	487.0%	2,700,581	-15.0%	2,535,425	-6.1%
97	(566) Miscellaneous Transmission Expenses	3,186,342	4,779,166	50.0%	3,137,388	-34.4%	3,600,428	14.8%
98	(567) Rents	310,624	320,129	3.1%	329,966	3.1%	340,147	3.1%
99	TOTAL Operation (Enter Total of lines 83 thru 98)	8,754,207	12,428,575	42.0%	9,527,028	-23.3%	9,628,720	1.1%
100	Maintenance							
101	(568) Maintenance Supervision and Engineering	26,651	27,017	1.4%	23,243	-14.0%	24,142	3.9%
102	(569) Maintenance of Structures	27,571	21,837	-20.8%	15,526	-28.9%	27,498	77.1%
103	(569.1) Maintenance of Computer Hardware		685					
104	(569.2) Maintenance of Computer Software	237,510	276,143	16.3%	7,755	-97.2%	4,839	-37.6%
105	(569.3) Maintenance of Communication Equipment	20,850	19,423	-6.8%	34,319	76.7%	31,563	-8.0%
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant							
107	(570) Maintenance of Station Equipment	2,108,630	3,005,563	42.5%	2,807,075	-6.6%	2,860,584	1.9%
108	(571) Maintenance of Overhead Lines	7,077,675	5,801,524	-18.0%	5,213,367	-10.1%	5,133,521	-1.5%
109	(572) Maintenance of Underground Lines	4,969	5,497	10.6%	99,900	1717.4%	15,803	-84.2%
110	(573) Maintenance of Miscellaneous Transmission Plant	117,856	120,449	2.2%	255,156	111.8%	245,447	-3.8%
111	TOTAL Maintenance (Total of lines 101 thru 110)	9,621,712	9,278,138	-3.6%	8,456,341	-8.9%	8,343,397	-1.3%
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	18,375,919	21,706,713	18.1%	17,983,369	-17.2%	17,972,117	-0.1%
113	3. REGIONAL MARKET EXPENSES							
114	Operation							
115	(575.1) Operation Supervision							
116	(575.2) Day-Ahead and Real-Time Market Facilitation							
117	(575.3) Transmission Rights Market Facilitation							
118	(575.4) Capacity Market Facilitation							
119	(575.5) Ancillary Services Market Facilitation							
120	(575.6) Market Monitoring and Compliance							
121	(575.7) Market Facilitation, Monitoring and Compliance Services							
122	(575.8) Rents							
123	Total Operation (Lines 115 thru 122)	-	-		-		-	
124	Maintenance							
125	(576.1) Maintenance of Structures and Improvements							
126	(576.2) Maintenance of Computer Hardware							
127	(576.3) Maintenance of Computer Software							
128	(576.4) Maintenance of Communication Equipment							
129	(576.5) Maintenance of Miscellaneous Market Operation Plant							
130	Total Maintenance (Lines 125 thru 129)	-	-		-		-	
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	-	-		-		-	
132	4. DISTRIBUTION EXPENSES							
133	Operation							
134	(580) Operation Supervision and Engineering	779,109	872,900	12.0%	866,816	-0.7%	846,719	-2.3%
135	(581) Load Dispatching	822,362	853,315	3.8%	967,713	13.4%	973,693	0.6%
136	(582) Station Expenses	514,721	605,612	17.7%	605,692	0.0%	574,535	-5.1%
137	(583) Overhead Line Expenses	957,868	1,135,897	18.6%	1,392,041	22.5%	1,464,753	5.2%
138	(584) Underground Line Expenses	232,277	239,055	2.9%	236,491	-1.1%	241,818	2.3%
139	(585) Street Lighting and Signal System Expenses	354,753	364,433	2.7%	337,282	-7.5%	416,277	23.4%
140	(586) Meter Expenses	1,102,566	1,203,304	9.1%	1,512,216	25.7%	1,075,373	-28.9%
141	(587) Customer Installations Expenses	2,396	10,056	319.7%	15,547	54.6%	24,362	56.7%
142	(588) Miscellaneous Expenses	6,818,094	7,189,569	5.4%	7,452,109	3.7%	7,483,654	0.4%
143	(589) Rents	2,153,924	2,194,151	1.9%	2,305,730	5.1%	2,169,852	-5.9%
144	TOTAL Operation (Enter Total of lines 134 thru 143)	13,738,070	14,668,292	6.8%	15,691,637	7.0%	15,271,036	-2.7%
145	Maintenance							
146	(590) Maintenance Supervision and Engineering	349,530	335,207	-4.1%	301,837	-10.0%	247,985	-17.8%
147	(591) Maintenance of Structures	6,515	10,711	64.4%	10,205	-4.7%	6,720	-34.1%
148	(592) Maintenance of Station Equipment	3,241,604	4,062,082	25.3%	3,663,286	-9.8%	3,516,089	-4.0%
149	(593) Maintenance of Overhead Lines	20,570,036	23,352,456	13.5%	27,623,945	18.3%	26,028,775	-5.8%
150	(594) Maintenance of Underground Lines	2,881,636	2,913,368	1.1%	2,774,804	-4.8%	3,121,335	12.5%
151	(595) Maintenance of Line Transformers	236,236	264,794	12.1%	167,226	-36.8%	134,260	-19.7%
152	(596) Maintenance of Street Lighting and Signal Systems	2,429,126	2,625,330	8.1%	2,715,852	3.4%	3,634,155	33.8%
153	(597) Maintenance of Meters	242,053	222,295	-8.2%	302,672	36.2%	311,848	3.0%
154	(598) Maintenance of Miscellaneous Distribution Plant	2,928,070	3,017,972	3.1%	2,886,479	-4.4%	2,975,746	3.1%
155	TOTAL Maintenance (Total of lines 146 thru 154)	32,884,806	36,804,215	11.9%	40,446,306	9.9%	39,976,913	-1.2%
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	46,622,876	51,472,507	10.4%	56,137,943	9.1%	55,247,949	-1.6%
157	5. CUSTOMER ACCOUNTS EXPENSES							
158	Operation							
159	(901) Supervision	1,403,786	1,503,947	7.1%	1,699,047	13.0%	1,558,673	-8.3%
160	(902) Meter Reading Expenses	1,764,521	1,616,362	-8.4%	1,772,854	9.7%	1,895,936	6.9%
161	(903) Customer Records and Collection Expenses	34,971,822	36,424,169	4.2%	36,529,324	0.3%	35,636,476	-2.4%
162	(904) Uncollectible Accounts	6,185,902	7,009,696	13.3%	5,697,561	-18.7%	5,927,251	4.0%
163	(905) Miscellaneous Customer Accounts Expenses	2,411,333	2,246,450	-6.8%	2,295,274	2.2%	2,812,218	22.5%
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	46,737,364	48,800,624	4.4%	47,994,060	-1.7%	47,830,554	-0.3%

Line No	Account	2013	2014	% Incr(Decr)	2015	% Incr(Decr)	2016	% Incr(Decr)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES							
166	Operation							
167	(907) Supervision	380,289	330,730	-13.0%	319,698	-3.3%	278,681	-12.8%
168	(908) Customer Assistance Expenses	6,991,770	8,973,332	28.3%	12,828,632	43.0%	14,392,900	12.2%
169	(909) Informational and Instructional Expenses	1,638	1,960	19.7%				
170	(910) Miscellaneous Customer Service and Informational Expenses	324,590	272,209	-16.1%	281,313	3.3%	98,018	-65.2%
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	7,698,287	9,578,231	24.4%	13,429,643	40.2%	14,769,599	10.0%
172	7. SALES EXPENSES							
173	Operation							
174	(911) Supervision	281	1,083	285.4%				
175	(912) Demonstrating and Selling Expenses	1,350,575	1,443,258	6.9%	1,504,308	4.2%	1,195,106	-20.6%
176	(913) Advertising Expenses	293	(23)	-107.8%	(3,158)	13630.4%	1,872	-159.3%
177	(916) Miscellaneous Sales Expenses	274,206	192,080	-30.0%	253,830	32.1%	227,932	-10.2%
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,625,355	1,636,398	0.7%	1,754,980	7.2%	1,424,910	-18.8%
179	8. ADMINISTRATIVE AND GENERAL EXPENSES							
180	Operation							
181	(920) Administrative and General Salaries	49,262,065	55,094,303	11.8%	56,641,077	2.8%	63,602,777	12.3%
182	(921) Office Supplies and Expenses	18,636,855	19,847,487	6.5%	17,782,876	-10.4%	18,141,449	2.0%
183	(Less) (922) Administrative Expenses Transferred-Credit							
184	(923) Outside Services Employed	11,467,274	13,867,035	20.9%	15,282,833	10.2%	13,514,667	-11.6%
185	(924) Property Insurance	6,648,738	7,063,100	6.2%	6,719,399	-4.9%	7,022,817	4.5%
186	(925) Injuries and Damages	5,898,902	5,858,213	-0.7%	6,982,006	19.2%	6,898,273	-1.2%
187	(926) Employee Pensions and Benefits	52,466,913	44,906,622	-14.4%	39,648,705	-11.7%	55,383,403	39.7%
188	(927) Franchise Requirements	5,588	7,641	36.7%	8,569	12.1%	6,077	-29.1%
189	(928) Regulatory Commission Expenses	5,968,418	5,051,779	-15.4%	5,324,591	5.4%	5,244,577	-1.5%
190	(929) (Less) Duplicate Charges-Cr.	(11,077,471)	(9,365,973)	-15.5%	(8,786,659)	-6.2%	(8,142,846)	-7.3%
191	(930.1) General Advertising Expenses	20,081	39,790	98.1%	157	-99.6%	20,700	13084.7%
192	(930.2) Miscellaneous General Expenses	13,830,541	16,485,465	19.2%	16,226,454	-1.6%	18,051,631	11.2%
193	(931) Rents	4,710,607	4,117,652	-12.6%	4,779,376	16.1%	5,078,266	6.3%
194	TOTAL Operation (Enter Total of lines 181 thru 193)	157,838,511	162,973,114	3.3%	160,609,384	-1.5%	184,821,791	15.1%
195	Maintenance							
196	(935) Maintenance of General Plant + 9320000 (+605.00)	5,530,961	6,442,313	16.5%	6,334,105	-1.7%	6,905,304	9.0%
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	163,369,472	169,415,427	3.7%	166,943,489	-1.5%	191,727,095	14.8%
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	###########	###########	8.0%	###########	-11.3%	###########	-3.7%

Form **8453-C**

Department of the Treasury
Internal Revenue Service

U.S. Corporation Income Tax Declaration for an IRS *e-file* Return

▶ File electronically with the corporation's tax return Do not file paper copies
▶ Information about Form 8453-C and its instructions is at *www irs gov/form8453c*

For calendar year 2016, or tax year beginning , ending

OMB No 1545-0123

2016

Name of corporation: SCANA CORPORATION

Employer identification number: 57-0784499

Part I Tax Return Information (Whole dollars only)

1	Total income (Form 1120, line 11)	1	2,612,525,249.
2	Taxable income (Form 1120, line 30)	2	-57,112,028.
3	Total tax (Form 1120, line 31)	3	NONE
4	Amount owed (Form 1120, line 34)	4	
5	Overpayment (Form 1120, line 35)	5	6,237,866.

Part II Declaration of Officer (see instructions) **Be sure to keep a copy of the corporation's tax return.**

6a [X] I consent that the corporation's refund be directly deposited as designated on the **Form 8050**, Direct Deposit of Corporate Tax Refund, that will be electronically transmitted with the corporation's 2016 federal income tax return

b [ ] I do not want direct deposit of the corporation's refund or the corporation is not receiving a refund

c [ ] I authorize the U S Treasury and its designated Financial Agent to initiate an electronic funds withdrawal (direct debit) entry to the financial institution account indicated in the tax preparation software for payment of the corporation's federal taxes owed on this return, and the financial institution to debit the entry to this account To revoke a payment, I must contact the U S Treasury Financial Agent at **1-888-353-4537** no later than 2 business days prior to the payment (settlement) date I also authorize the financial institutions involved in the processing of the electronic payment of taxes to receive confidential information necessary to answer inquiries and resolve issues related to the payment

If the corporation is filing a balance due return, I understand that if the IRS does not receive full and timely payment of its tax liability, the corporation will remain liable for the tax liability and all applicable interest and penalties

Under penalties of perjury, I declare that I am an officer of the above corporation and that the information I have given my electronic return originator (ERO), transmitter, and/or intermediate service provider (ISP) and the amounts in Part I above agree with the amounts on the corresponding lines of the corporation's 2016 federal income tax return To the best of my knowledge and belief, the corporation's return is true, correct, and complete I consent to my ERO, transmitter, and/or ISP sending the corporation's return, this declaration, and accompanying schedules and statements to the IRS I also consent to the IRS sending my ERO, transmitter, and/or ISP an acknowledgment of receipt of transmission and an indication of whether or not the corporation's return is accepted, and, if rejected, the reason(s) for the rejection If the processing of the corporation's return or refund is delayed, I authorize the IRS to disclose to my ERO, transmitter, and/or ISP the reason(s) for the delay, or when the refund was sent

Sign Here ▶ Signature of officer | 09/28/2017 Date | ▶ CONTROLLER Title

Part III Declaration of Electronic Return Originator (ERO) and Paid Preparer (see instructions)

I declare that I have reviewed the above corporation's return and that the entries on Form 8453-C are complete and correct to the best of my knowledge If I am only a collector, I am not responsible for reviewing the return and only declare that this form accurately reflects the data on the return The corporate officer will have signed this form before I submit the return I will give the officer a copy of all forms and information to be filed with the IRS, and have followed all other requirements in Pub 3112, IRS *e-file* Application and Participation, and Pub 4163, Modernized e-File (MeF) Information for Authorized IRS *e-file* Providers for Business Returns If I am also the Paid Preparer, under penalties of perjury, I declare that I have examined the above corporation's return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete This Paid Preparer declaration is based on all information of which I have any knowledge

ERO's Use Only				
ERO's signature ▶	Date	Check if also paid preparer [X]	Check if self-employed [ ]	ERO's SSN or PTIN
Firm's name (or yours if self-employed), address, and ZIP code ▶				EIN
				Phone no

Under penalties of perjury, I declare that I have examined the above corporation's return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete This declaration is based on all information of which I have any knowledge

Paid Preparer Use Only					
Print/Type preparer's name	Preparer's signature	Date	Check [ ] if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no	

For Privacy Act and Paperwork Reduction Act Notice, see instructions Form **8453-C** (2016)

JSA
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Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2016 or tax year beginning ____________, ending ____________

▶ Information about Form 1120 and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123 **2016**

A Check if:		TYPE OR PRINT		B Employer identification number
1a Consolidated return (attach Form 851)	X	Name	SCANA CORPORATION	57-0784499
b Life/nonlife consolidated return		Number, street, and room or suite no. If a P.O. box, see instructions.	220 OPERATION WAY	C Date incorporated 10/01/1984
2 Personal holding co. (attach Sch. PH)		City or town, state, or province, country, and ZIP or foreign postal code	CAYCE, SC 29033-3701	D Total assets (see instructions) $ 18,706,879,069.
3 Personal service corp. (see instructions)				
4 Schedule M-3 attached	X			

E Check if: (1) ☐ Initial return (2) ☐ Final return (3) ☐ Name change (4) ☐ Address change

Income

Line	Description			Line	Amount
1a	Gross receipts or sales	1a	4,497,365,433.		
b	Returns and allowances	1b			
c	Balance. Subtract line 1b from line 1a			1c	4,497,365,433.
2	Cost of goods sold (attach Form 1125-A)			2	2,118,180,744.
3	Gross profit. Subtract line 2 from line 1c			3	2,379,184,689.
4	Dividends (Schedule C, line 19)			4	337,492.
5	Interest			5	241,238,458.
6	Gross rents			6	15,809,392.
7	Gross royalties			7	
8	Capital gain net income (attach Schedule D (Form 1120))			8	230,794.
9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	-51,771,917.
10	Other income (see instructions - attach statement) See Statement 4			10	27,496,341.
11	**Total income.** Add lines 3 through 10 ▶			11	2,612,525,249.

Deductions (See instructions for limitations on deductions.)

Line	Description			Line	Amount
12	Compensation of officers (see instructions - attach Form 1125-E) ▶			12	15,144,833.
13	Salaries and wages (less employment credits)			13	80,503,050.
14	Repairs and maintenance			14	248,721,590.
15	Bad debts			15	10,347,235.
16	Rents			16	4,696,539.
17	Taxes and licenses			17	256,620,275.
18	Interest			18	385,177,623.
19	Charitable contributions See Statement 6			19	NONE
20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	674,906,524.
21	Depletion			21	
22	Advertising			22	12,485,413.
23	Pension, profit-sharing, etc., plans			23	694,957.
24	Employee benefit programs			24	56,802,808.
25	Domestic production activities deduction (attach Form 8903)			25	
26	Other deductions (attach statement) See Statement 7			26	923,324,230.
27	**Total deductions.** Add lines 12 through 26 ▶			27	2,669,425,077.
28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11			28	-56,899,828.
29a	Net operating loss deduction (see instructions)	29a	NONE		Stmt 10
b	Special deductions (Schedule C, line 20)	29b	212,200.		
c	Add lines 29a and 29b			29c	212,200.

Tax, Refundable Credits, and Payments

Line	Description	Line	Amount
30	**Taxable income.** Subtract line 29c from line 28. See instructions	30	-57,112,028.
31	Total tax (Schedule J, Part I, line 11)	31	NONE
32	Total payments and refundable credits (Schedule J, Part II, line 21)	32	6,237,866.
33	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶ ☐	33	
34	**Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed	34	
35	**Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid	35	6,237,866.
36	Enter amount from line 35 you want: **Credited to 2017 estimated tax** ▶ **Refunded** ▶	36	6,237,866.

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer JAMES E SWAN IV | Date 09/28/2017 | Title CONTROLLER

May the IRS discuss this return with the preparer shown below? See instructions. ☐ Yes ☒ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

For Paperwork Reduction Act Notice, see separate instructions. Form **1120** (2016)

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page **2**

Schedule C Dividends and Special Deductions (see instructions)	(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	303,143.	70	212,200.
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3 Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Total.** Add lines 1 through 8. See instructions for limitation			212,200.
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members		100	
12 Dividends from certain FSCs		100	
13 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, or 12	34,349.		
14 Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15 Foreign dividend gross-up			
16 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
17 Other dividends			
18 Deduction for dividends paid on certain preferred stock of public utilities			
19 **Total dividends.** Add lines 1 through 17. Enter here and on page 1, line 4 ▶	337,492.		
20 **Total special deductions.** Add lines 9, 10, 11, 12, and 18. Enter here and on page 1, line 29b ▶			212,200.

SCANA CORPORATION 57-0784499

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

Line	Description	Sub-line	Sub-amount	Line	Amount
1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ ☐				
2	Income tax. Check if a qualified personal service corporation. See instructions ▶ ☐			2	
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	NONE
5a	Foreign tax credit (attach Form 1118)	5a			
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c			
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	
7	Subtract line 6 from line 4			7	NONE
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	NONE

Part II-Payments and Refundable Credits

Line	Description	Sub-line	Sub-amount	Line	Amount
12	2015 overpayment credited to 2016			12	
13	2016 estimated tax payments			13	6,000,000.
14	2016 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	6,000,000.
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	**Total payments.** Add lines 15, 16, and 17			18	6,000,000.
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	237,866.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	237,866.
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	6,237,866.

Schedule K Other Information (see instructions)

Line	Description	Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

SCANA CORPORATION 57-0784499

Schedule K **Other Information** *(continued from page 3)*

		Yes	No
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851,** Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.		X

(i) Name of Corporation	**(ii)** Employer Identification Number (if any)	**(iii)** Country of Incorporation	**(iv)** Percentage Owned in Voting Stock

		Yes	No
b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below. See Statement 14	X	

(i) Name of Entity	**(ii)** Employer Identification Number (if any)	**(iii)** Country of Organization	**(iv)** Maximum Percentage Owned in Profit, Loss, or Capital

		Yes	No
6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316		X
	If "Yes," file **Form 5452,** Corporate Report of Nondividend Distributions. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7	At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of **(a)** the total voting power of all classes of the corporation's stock entitled to vote or **(b)** the total value of all classes of the corporation's stock?		X
	For rules of attribution, see section 318. If "Yes," enter: **(i)** Percentage owned ▶ ____ and **(ii)** Owner's country ▶ ____		
	(c) The corporation may have to file **Form 5472,** Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ ____		
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐ If checked, the corporation may have to file **Form 8281,** Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $ ____		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶ ____		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here ▶ ☐ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election won't be valid.		
12	Enter the available NOL carryover from prior tax years (don't reduce it by any deduction on line 29a.) ▶ $ ____		
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
	If "Yes," the corporation isn't required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $ ____		
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions	X	
	If "Yes," complete and attach Schedule UTP.		
15a	Did the corporation make any payments in 2016 that would require it to file Form(s) 1099?	X	
b	If "Yes," did or will the corporation file required Forms 1099?	X	
16	During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?	X	

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page **5**

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	(b)	End of tax year (c)	(d)
1 Cash		236,349,831.		207,880,557.
2a Trade notes and accounts receivable	682,391,843.		733,184,381.	
b Less allowance for bad debts	(5,269,711.)	677,122,132.	(5,853,608.)	727,330,773.
3 Inventories		311,778,910.		290,480,845.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 21	151,782,083.		280,369,350.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 23	240,146,412.		198,711,256.
10a Buildings and other depreciable assets	18,667,897,661.		20,054,957,957.	
b Less accumulated depreciation	(5,975,136,607.)	12,692,761,054.	(5,454,272,723.)	14,600,685,234.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)				
13a Intangible assets (amortizable only)				
b Less accumulated amortization	( )		( )	
14 Other assets (attach statement)	Stmt 24	2,479,478,762.		2,401,421,054.
15 Total assets		16,789,419,184.		18,706,879,069.
Liabilities and Shareholders' Equity				
16 Accounts payable		576,643,248.		388,631,752.
17 Mortgages, notes, bonds payable in less than 1 year		647,291,449.		957,426,831.
18 Other current liabilities (attach statement)	Stmt 27	653,922,195.		719,026,809.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		5,904,834,401.		6,472,928,061.
21 Other liabilities (attach statement)	Stmt 30	3,562,331,009.		4,443,834,268.
22 Capital stock: a Preferred stock				
b Common stock	2,417,595,500.	2,417,595,500.	2,417,595,500.	2,417,595,500.
23 Additional paid-in capital		-14,282,362.		-14,282,362.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		3,118,303,738.		3,383,244,353.
26 Adjustments to shareholders' equity (attach statement)		-65,427,485.		-49,050,610.
27 Less cost of treasury stock		(11,792,509.)		(12,475,533.)
28 Total liabilities and shareholders' equity		16,789,419,184.		18,706,879,069.

Schedule M-1 **Reconciliation of Income (Loss) per Books With Income per Return**

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 **Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)**

1 Balance at beginning of year	3,118,303,738.	5 Distributions: a Cash	329,908,943.
2 Net income (loss) per books	594,849,551.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 36	-5.
See Statement 36	2.	7 Add lines 5 and 6	329,908,938.
4 Add lines 1, 2, and 3	3,713,153,291.	8 Balance at end of year (line 4 less line 7)	3,383,244,353.

SCHEDULE G (Form 1120)
(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Information on Certain Persons Owning the Corporation's Voting Stock

▶ Attach to Form 1120.
▶ See instructions on page 2.

OMB No. 1545-0123

Name: SCANA CORPORATION

Employer identification number (EIN): 57-0784499

Part I **Certain Entities Owning the Corporation's Voting Stock.** (Form 1120, Schedule K, Question 4a). Complete columns (i) through (v) below for any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization that owns directly 20% or more, or owns, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote (see instructions).

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Type of Entity	(iv) Country of Organization	(v) Percentage Owned in Voting Stock

Part II **Certain Individuals and Estates Owning the Corporation's Voting Stock.** (Form 1120, Schedule K, Question 4b). Complete columns (i) through (iv) below for any individual or estate that owns directly 20% or more, or owns, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote (see instructions).

(i) Name of Individual or Estate	(ii) Identifying Number (if any)	(iii) Country of Citizenship (see instructions)	(iv) Percentage Owned in Voting Stock

Form **4626**

Department of the Treasury
Internal Revenue Service

Alternative Minimum Tax - Corporations

▶ Attach to the corporation's tax return.

▶ Information about Form 4626 and its separate instructions is at *www.irs.gov/form4626*.

OMB No. 1545-0123

2016

Name	Employer identification number
SCANA CORPORATION	57-0784499

Note: *See the instructions to find out if the corporation is a small corporation exempt from the alternative minimum tax (AMT) under section 55(e).*

1	Taxable income or (loss) before net operating loss deduction			1	-57,112,028.
2	**Adjustments and preferences:**				
a	Depreciation of post-1986 property			2a	-22,424,670.
b	Amortization of certified pollution control facilities			2b	
c	Amortization of mining exploration and development costs			2c	
d	Amortization of circulation expenditures (personal holding companies only)			2d	
e	Adjusted gain or loss			2e	1,703,217.
f	Long-term contracts			2f	
g	Merchant marine capital construction funds			2g	
h	Section 833(b) deduction (Blue Cross, Blue Shield, and similar type organizations only)			2h	
i	Tax shelter farm activities (personal service corporations only)			2i	
j	Passive activities (closely held corporations and personal service corporations only)			2j	
k	Loss limitations			2k	
l	Depletion			2l	
m	Tax-exempt interest income from specified private activity bonds			2m	
n	Intangible drilling costs			2n	
o	Other adjustments and preferences . . . See Statement 41			2o	NONE
3	Pre-adjustment alternative minimum taxable income (AMTI). Combine lines 1 through 2o			3	-77,833,481.
4	**Adjusted current earnings (ACE) adjustment:**				
a	ACE from line 10 of the ACE worksheet in the instructions	4a	-45,278,399.		
b	Subtract line 3 from line 4a. If line 3 exceeds line 4a, enter the difference as a negative amount. See instructions	4b	32,555,082.		
c	Multiply line 4b by 75% (0.75). Enter the result as a positive amount	4c	24,416,312.		
d	Enter the excess, if any, of the corporation's total increases in AMTI from prior year ACE adjustments over its total reductions in AMTI from prior year ACE adjustments. See instructions. **Note:** *You **must** enter an amount on line 4d (even if line 4b is positive)*	4d			
e	ACE adjustment. • If line 4b is zero or more, enter the amount from line 4c • If line 4b is less than zero, enter the **smaller** of line 4c or line 4d as a negative amount			4e	24,416,312.
5	Combine lines 3 and 4e. If zero or less, stop here; the corporation does not owe any AMT			5	-53,417,169.
6	Alternative tax net operating loss deduction. See instructions . . . See Statement 43			6	
7	**Alternative minimum taxable income.** Subtract line 6 from line 5. If the corporation held a residual interest in a REMIC, see instructions			7	-53,417,169.
8	**Exemption phase-out** (if line 7 is $310,000 or more, skip lines 8a and 8b and enter -0- on line 8c):				
a	Subtract $150,000 from line 7 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-	8a	NONE		
b	Multiply line 8a by 25% (0.25)	8b	NONE		
c	Exemption. Subtract line 8b from $40,000 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-			8c	40,000.
9	Subtract line 8c from line 7. If zero or less, enter -0-			9	NONE
10	Multiply line 9 by 20% (0.20)			10	NONE
11	Alternative minimum tax foreign tax credit (AMTFTC). See instructions			11	
12	Tentative minimum tax. Subtract line 11 from line 10			12	NONE
13	Regular tax liability before applying all credits except the foreign tax credit			13	
14	**Alternative minimum tax.** Subtract line 13 from line 12. If zero or less, enter -0-. Enter here and on Form 1120, Schedule J, line 3, or the appropriate line of the corporation's income tax return			14	NONE

Adjusted Current Earnings (ACE) Worksheet

Keep for Your Records

► See ACE Worksheet Instructions.

1		Pre-adjustment AMTI. Enter the amount from line 3 of Form 4626					1	-77,833,481.
2		ACE depreciation adjustment:						
	a	AMT depreciation			2a	697,331,191.		
	b	ACE depreciation:						
		(1) Post-1993 property	2b(1)	244,943,932.				
		(2) Post-1989, pre-1994 property	2b(2)					
		(3) Pre-1990 MACRS property	2b(3)					
		(4) Pre-1990 original ACRS property	2b(4)					
		(5) Property described in sections 168(f)(1) through (4)	2b(5)					
		(6) Other property	2b(6)	451,921,072.				
		(7) Total ACE depreciation. Add lines 2b(1) through 2b(6)			2b(7)	696,865,004.		
	c	ACE depreciation adjustment. Subtract line 2b(7) from line 2a					2c	466,187.
3		Inclusion in ACE of items included in earnings and profits (E&P):						
	a	Tax-exempt interest income			3a			
	b	Death benefits from life insurance contracts			3b	-268,623.		
	c	All other distributions from life insurance contracts (including surrenders)			3c			
	d	Inside buildup of undistributed income in life insurance contracts			3d	4,986,147.		
	e	Other items (see Regulations sections 1.56(g)-1(c)(6)(iii) through (ix) for a partial list)			3e			
	f	Total increase to ACE from inclusion in ACE of items included in E&P. Add lines 3a through 3e					3f	4,717,524.
4		Disallowance of items not deductible from E&P:						
	a	Certain dividends received			4a	212,200.		
	b	Dividends paid on certain preferred stock of public utilities that are deductible under section 247 (as affected by P.L. 113-295, Div. A, section 221(a)(41)(A), Dec. 19, 2014, 128 Stat. 4043)			4b			
	c	Dividends paid to an ESOP that are deductible under section 404(k)			4c	27,159,171.		
	d	Nonpatronage dividends that are paid and deductible under section 1382(c)			4d			
	e	Other items (see Regulations sections 1.56(g)-1(d)(3)(i) and (ii) for a partial list)			4e			
	f	Total increase to ACE because of disallowance of items not deductible from E&P. Add lines 4a through 4e					4f	27,371,371.
5		Other adjustments based on rules for figuring E&P:						
	a	Intangible drilling costs			5a			
	b	Circulation expenditures			5b			
	c	Organizational expenditures			5c			
	d	LIFO inventory adjustments			5d			
	e	Installment sales			5e			
	f	Total other E&P adjustments. Combine lines 5a through 5e					5f	
6		Disallowance of loss on exchange of debt pools					6	
7		Acquisition expenses of life insurance companies for qualified foreign contracts					7	
8		Depletion					8	
9		Basis adjustments in determining gain or loss from sale or exchange of pre-1994 property					9	NONE
10		**Adjusted current earnings.** Combine lines 1, 2c, 3f, 4f, and 5f through 9. Enter the result here and on line 4a of Form 4626					10	-45,278,399.

Form **8050**
(November 2016)
Department of the Treasury
Internal Revenue Service

Direct Deposit of Corporate Tax Refund

▶ **Attach to Form 1120 or 1120S.**

▶ **Information about Form 8050 and its instructions is at *www.irs.gov/form8050.***

OMB No. 1545-0123

Name of corporation (as shown on tax return)	**Employer identification number**
SCANA CORPORATION	57-0784499
	Phone number (optional)
	803 217-9000

1. Routing number (must be nine digits). The first two digits must be between 01 and 12 or 21 through 32.

[redacted]

2. Account number (include hyphens but omit spaces and special symbols):

[redacted]

3. Type of account (one box must be checked):

[X] Checking [ ] Savings

General Instructions

Section references are to the Internal Revenue Code unless otherwise noted.

Purpose of Form

File Form 8050 to request that the IRS deposit a corporate income tax refund (including a refund of $1 million or more) directly into an account at any U.S. bank or other financial institution (such as a mutual fund or brokerage firm) that accepts direct deposits.

The benefits of a direct deposit include a faster refund, the added security of a paperless payment, and the savings of tax dollars associated with the reduced processing costs.

Who May File

Only corporations requesting a direct deposit of refund with its original Form 1120 or 1120S may file Form 8050.

The corporation is not eligible to request a direct deposit if:

- The receiving financial institution is a foreign bank or a foreign branch of a U.S. bank, or
- The corporation has applied for an employer identification number but is filing its tax return before receiving one.

Note: For other corporate tax returns, including **Form 1120X,** Amended U.S. Corporation Income Tax Return, and **Form 1139,** Corporation Application for Tentative Refund, a corporation may request a direct deposit of refunds of $1 million or more by filing **Form 8302,** Electronic Deposit of Tax Refund of $1 Million or More.

Conditions Resulting in a Refund by Check

If the IRS is unable to process this request for a direct deposit, a refund by check will be generated instead. Reasons for not processing a request include:

- The name of the corporation on the tax return does not match the name on the account.
- The financial institution rejects the direct deposit because of an incorrect routing or account number.
- The corporation fails to indicate the type of account the deposit is to be made to (that is, checking or savings).

How To File

Attach Form 8050 to the corporation's Form 1120 or 1120S after Schedule N (Form 1120), if applicable. To ensure that the corporation's tax return is correctly processed, see **Assembling the Return** in the instructions for Form 1120 or 1120S.

Specific Instructions

Line 1. Enter the financial institution's routing number and verify that the institution will accept a direct deposit. See the sample check below for an example of where the routing number may be shown.

For accounts payable through a financial institution other than the one at which the account is located, check with your financial institution for the correct routing number. **Do not** use a deposit slip to verify the routing number.

Line 2. Enter the corporation's account number. Enter the number from left to right and leave any unused boxes blank. See the sample check below for an example of where the account number may be shown.

Paperwork Reduction Act Notice.

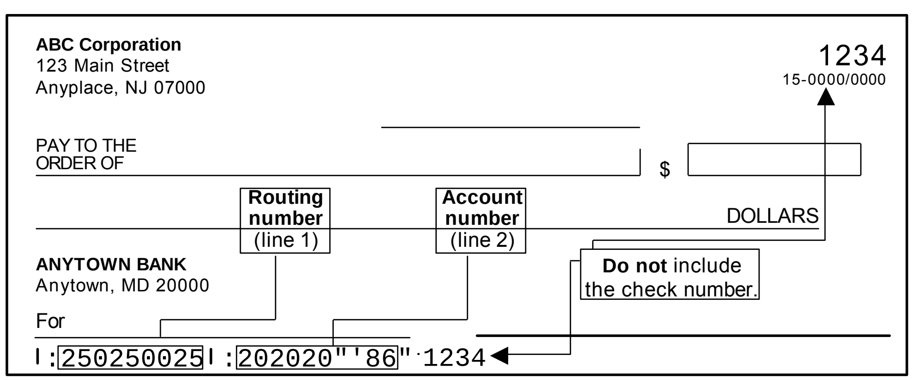
We ask for the information on this form to carry out the Internal Revenue laws of the United States. You are required to give us the information. We need it to ensure that you are complying with these laws and to allow us to figure and collect the right amount of tax.

You are not required to provide the information requested on a form that is subject to the Paperwork Reduction Act unless the form displays a valid OMB control number. Books or records relating to a form or its instructions must be retained as long as their contents may become material in the administration of any Internal Revenue law. Generally, tax returns and return information are confidential, as required by section 6103.

The time needed to complete and file this form will vary depending on individual circumstances. The estimated burden for business taxpayers filing this form is approved under OMB control number 1545-0123 and is included in the estimates shown in the instructions for their business income tax return.

If you have comments concerning the accuracy of these time estimates or suggestions for making this form simpler, we would be happy to hear from you. You can write to the IRS at the address listed in the instructions of the tax return with which this form is filed.

Sample Check



Note. The routing and account numbers may be in different places on the corporation's check.

Form **4136**

Department of the Treasury
Internal Revenue Service (99)

Credit for Federal Tax Paid on Fuels

▶ Information about Form 4136 and its separate instructions is at *www.irs.gov/form4136.*

OMB No. 1545-0162

2016

Attachment Sequence No. 23

Name (as shown on your income tax return)	Taxpayer identification number
SCANA CORPORATION	57-0784499

Caution: Claimant has the name and address of the person who sold the fuel to the claimant and the dates of purchase. For claims on lines 1c and 2b (type of use 13 or 14), 3d, 4c, and 5, claimant has not waived the right to make the claim. For claims on lines 1c and 2b (type of use 13 or 14), claimant certifies that a certificate has not been provided to the credit card issuer.

1 Nontaxable Use of Gasoline **Note:** CRN is credit reference number.

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Off-highway business use		$ .183	164195		
b	Use on a farm for farming purposes		.183		30,048.	362
c	Other nontaxable use (see **Caution** above line 1)		.183		$	
d	Exported		.184			411

2 Nontaxable Use of Aviation Gasoline

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use in commercial aviation (other than foreign trade)		$ .15		$	354
b	Other nontaxable use (see **Caution** above line 1)		.193			324
c	Exported		.194			412
d	LUST tax on aviation fuels used in foreign trade		.001			433

3 Nontaxable Use of Undyed Diesel Fuel

Claimant certifies that the diesel fuel did not contain visible evidence of dye.
Exception. If any of the diesel fuel included in this claim **did** contain visible evidence of dye, attach an explanation and check here ▶ ☐

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Nontaxable use		$ .243	137268		
b	Use on a farm for farming purposes		.243		$ 33,356.	360
c	Use in trains		.243			353
d	Use in certain intercity and local buses (see **Caution** above line 1)		.17			350
e	Exported		.244			413

4 Nontaxable Use of Undyed Kerosene (Other Than Kerosene Used in Aviation)

Claimant certifies that the kerosene did not contain visible evidence of dye.
Exception. If any of the kerosene included in this claim **did** contain visible evidence of dye, attach an explanation and check here ▶ ☐

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Nontaxable use taxed at $.244		$ .243			
b	Use on a farm for farming purposes		.243		$	346
c	Use in certain intercity and local buses (see **Caution** above line 1)		.17			347
d	Exported		.244			414
e	Nontaxable use taxed at $.044		.043			377
f	Nontaxable use taxed at $.219		.218			369

5 Kerosene Used in Aviation (see **Caution** above line 1)

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Kerosene used in commercial aviation (other than foreign trade) taxed at $.244		$ .200		$	417
b	Kerosene used in commercial aviation (other than foreign trade) taxed at $.219		.175			355
c	Nontaxable use (other than use by state or local government) taxed at $.244		.243			346
d	Nontaxable use (other than use by state or local government) taxed at $.219		.218			369
e	LUST tax on aviation fuels used in foreign trade		.001			433

6 Sales by Registered Ultimate Vendors of Undyed Diesel Fuel **Registration No. ▶**

Claimant certifies that it sold the diesel fuel at a tax-excluded price, repaid the amount of tax to the buyer, or has obtained the written consent of the buyer to make the claim. Claimant certifies that the diesel fuel did not contain visible evidence of dye.

Exception. If any of the diesel fuel included in this claim **did** contain visible evidence of dye, attach an explanation and check here ▶ ☐

		(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use by a state or local government	$ .243		$	360
b	Use in certain intercity and local buses	.17			350

7 Sales by Registered Ultimate Vendors of Undyed Kerosene (Other Than Kerosene For Use in Aviation) **Registration No. ▶**

Claimant certifies that it sold the kerosene at a tax-excluded price, repaid the amount of tax to the buyer, or has obtained the written consent of the buyer to make the claim. Claimant certifies that the kerosene did not contain visible evidence of dye.

Exception. If any of the kerosene included in this claim **did** contain visible evidence of dye, attach an explanation and check here ▶ ☐

		(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use by a state or local government	$ .243			
b	Sales from a blocked pump	.243		$	346
c	Use in certain intercity and local buses	.17			347

8 Sales by Registered Ultimate Vendors of Kerosene For Use in Aviation **Registration No. ▶**

Claimant sold the kerosene for use in aviation at a tax-excluded price and has not collected the amount of tax from the buyer, repaid the amount of tax to the buyer, or has obtained the written consent of the buyer to make the claim. See the instructions for additional information to be submitted.

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use in commercial aviation (other than foreign trade) taxed at $.219		$ .175		$	355
b	Use in commercial aviation (other than foreign trade) taxed at $.244		.200			417
c	Nonexempt use in noncommercial aviation		.025			418
d	Other nontaxable uses taxed at $.244		.243			346
e	Other nontaxable uses taxed at $.219		.218			369
f	LUST tax on aviation fuels used in foreign trade		.001			433

9 Reserved **Registration No. ▶**

	(b) Rate	(c) Gallons of alcohol	(d) Amount of credit	(e) CRN
a Reserved				
b Reserved				

10 Biodiesel or Renewable Diesel Mixture Credit **Registration No. ▶**

Biodiesel mixtures. Claimant produced a mixture by mixing biodiesel with diesel fuel. The biodiesel used to produce the mixture met ASTM D6751 and met EPA's registration requirements for fuels and fuel additives. The mixture was sold by the claimant to any person for use as a fuel or was used as a fuel by the claimant. Claimant has attached the Certificate for Biodiesel and, if applicable, the Statement of Biodiesel Reseller. **Renewable diesel mixtures.** Claimant produced a mixture by mixing renewable diesel with liquid fuel (other than renewable diesel). The renewable diesel used to produce the renewable diesel mixture was derived from biomass process, met EPA's registration requirements for fuels and fuel additives, and met ASTM D975, D396, or other equivalent standard approved by the IRS. The mixture was sold by the claimant to any person for use as a fuel or was used as a fuel by the claimant. Claimant has attached the Certificate for Biodiesel and, if applicable, the Statement of Biodiesel Reseller, both of which have been edited as discussed in the Instructions for Form 4136. See the instructions for line 10 for information about renewable diesel used in aviation.

	(b) Rate	(c) Gallons of biodiesel or renewable diesel	(d) Amount of credit	(e) CRN
a Biodiesel (other than agri-biodiesel) mixtures	$1.00		$	388
b Agri-biodiesel mixtures	$1.00			390
c Renewable diesel mixtures	$1.00			307

11 Nontaxable Use of Alternative Fuel

Caution: There is a reduced credit rate for use in certain intercity and local buses (type of use 5) (see instructions).

	(a) Type of use	(b) Rate	(c) Gallons, or gasoline or diesel gallon equivalents	(d) Amount of credit	(e) CRN
a Liquefied petroleum gas (LPG) (see instructions)		$.183		$	419
b "P Series" fuels		.183			420
c Compressed natural gas (CNG) (see instructions)		.183			421
d Liquefied hydrogen		.183			422
e Fischer-Tropsch process liquid fuel from coal (including peat)		.243			423
f Liquid fuel derived from biomass		.243			424
g Liquefied natural gas (LNG) (see instructions)		.243			425
h Liquefied gas derived from biomass		.183			435

12 Alternative Fuel Credit **Registration No. ▶**

	(b) Rate	(c) Gallons, or gasoline or diesel gallon equivalents	(d) Amount of credit	(e) CRN
a Liquefied petroleum gas (LPG) (see instructions)	$ .50		$	426
b "P Series" fuels	.50			427
c Compressed natural gas (CNG) (see instructions)	.50	348923	174,462.	428
d Liquefied hydrogen	.50			429
e Fischer-Tropsch process liquid fuel from coal (including peat)	.50			430
f Liquid fuel derived from biomass	.50			431
g Liquefied natural gas (LNG) (see instructions)	.50			432
h Liquefied gas derived from biomass	.50			436
i Compressed gas derived from biomass	.50			437

13 Registered Credit Card Issuers **Registration No. ▶**

		(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Diesel fuel sold for the exclusive use of a state or local government	$ .243		$	360
b	Kerosene sold for the exclusive use of a state or local government	.243			346
c	Kerosene for use in aviation sold for the exclusive use of a state or local government taxed at $.219	.218			369

14 Nontaxable Use of a Diesel-Water Fuel Emulsion

Caution: There is a reduced credit rate for use in certain intercity and local buses (type of use 5) (see instructions).

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Nontaxable use		$ .197		$	309
b	Exported		.198			306

15 Diesel-Water Fuel Emulsion Blending **Registration No. ▶**

	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
Blender credit	$ .046		$	310

16 Exported Dyed Fuels and Exported Gasoline Blendstocks

		(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Exported dyed diesel fuel and exported gasoline blendstocks taxed at $.001	$ .001		$	415
b	Exported dyed kerosene	.001			416

17	**Total income tax credit claimed.** Add lines 1 through 16, column (d). Enter here and on Form 1040, line 72; Form 1120, Schedule J, line 19b; Form 1120S, line 23c; Form 1041, line 24g; or the proper line of other returns. ▶	17	$ 237,866.	

SCHEDULE B (Form 1120)
(Rev. December 2014)
Department of the Treasury
Internal Revenue Service

Additional Information for Schedule M-3 Filers

▶ Attach to Form 1120.
▶ See instructions on page 2.

OMB No. 1545-0123

Name: SCANA CORPORATION

Employer identification number (EIN): 57-0784499

		Yes	No
1	Does any amount reported on Schedule M-3 (Form 1120), Part II, lines 9 or 10, column (d), reflect allocations to this corporation from a partnership of income, gain, loss, deduction, or credit that are disproportionate to this corporation's capital contribution to the partnership or its ratio for sharing other items of the partnership?		X
2	At any time during the tax year, did the corporation sell, exchange, or transfer any interest in an intangible asset to a related person as defined in section 267(b)?	X	
3	At any time during the tax year, did the corporation acquire any interest in an intangible asset from a related person as defined in section 267(b)?	X	
4a	During the tax year, did the corporation enter into a cost-sharing arrangement with any related foreign party on whose behalf the corporation did not file Form 5471, Information Return of U.S. Persons With Respect To Certain Foreign Corporations?		X
b	At any time during the tax year, was the corporation a participant in a cost-sharing arrangement with any related foreign party on whose behalf the corporation did not file Form 5471?		X
5	At any time during the tax year, did the corporation make any change in accounting principle for financial accounting purposes? See instructions for the definition of change in accounting principle		X
6	At any time during the tax year, did the corporation make any change in a method of accounting for U.S. income tax purposes?		X
7	At any time during the tax year, did the corporation own any voluntary employees' beneficiary association (VEBA) trusts that were used to hold funds designated for employee benefits?	X	
8	At any time during the tax year, did the corporation use an allocation method for indirect costs capitalized to self-constructed assets that varied from its financial method of accounting?		X
9	At any time during the tax year, did the corporation treat for tax purposes indirect costs, as defined in Regulations sections 1.263A-1(e)(3)(ii)(F), (G), and (H), as mixed-service costs, as defined in Regulations section 1.263A-1(e)(4)(ii)(C)?	X	
10	Did the corporation, under section 118 or 362(c) and the related regulations, take a return filing position characterizing any amount as a contribution to the capital of the corporation during the tax year by any non-shareholders? Amounts so characterized may include, without limitation, incentives, inducements, money, and property	X	

Form **851** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Affiliations Schedule

For tax year ending 12/31/2016

▶File with each consolidated income tax return.

▶ Information about Form 851 and its instructions is at *www.irs.gov/form851*.

OMB No. 1545-0123

Name of common parent corporation: SCANA CORPORATION

Employer identification number: 57-0784499

Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY

City or town, state, and ZIP code: CAYCE, SC 29033-3701

Part I Overpayment Credits, Estimated Tax Payments, and Tax Deposits (see instructions)

Corp. No.	Name and address of corporation	Employer identification number	Portion of overpayment credits and estimated tax payments	Portion of tax deposited with Form 7004
1	Common parent corporation		6,000,000.	
	Subsidiary corporations:			
2	SCANA SERVICES INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-1092169		
3	SOUTH CAROLINA ELECTRIC and GAS COMPANY 220 OPERATION WAY CAYCE, SC 29033-3701	57-0248695		
4	SOUTH CAROLINA FUEL CO INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0691209		
5	SC GENERATING COMPANY INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0784498		
6	SCANA COMMUNICATIONS HOLDINGS INC 1011 CENTRE ROAD SUITE 322 WILMINGTON, DE 19805	51-0394908		
7	SCANA ENERGY MARKETING INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0850977		
	Totals (Must equal amounts shown on the consolidated tax return.) . . . . ▶		6,000,000.	

Part II Principal Business Activity, Voting Stock Information, Etc. (see instructions)

Corp. No.	Principal business activity (PBA)	PBA Code No.	Did the subsidiary make any nondividend distributions? Yes	No	Stock holdings at beginning of year: Number of shares	Percentage of voting power	Percentage of value	Owned by corporation no.
1	Common parent corporation HOLDING COMPANY	551112						
	Subsidiary corporations:							
2	SERVICES	541990		X	1,000	100.00 %	100.00 %	1
3	UTILITY	221100		X	40,296,147	100.00 %	100.00 %	1
4	WHOLESALE	423520		X	1	100.00 %	100.00 %	1
5	Utility	221112		X	1	100.00 %	100.00 %	1
6	OTHER INVESTMENT ACTIVITY	523999		X	1	100.00 %	100.00 %	1
7	MARKETING	221210		X	1	100.00 %	100.00 %	1

Form **851** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Affiliations Schedule

For tax year ending 12/31/2016

▶File with each consolidated income tax return.

▶ Information about Form 851 and its instructions is at *www.irs.gov/form851*.

OMB No. 1545-0123

Name of common parent corporation	Employer identification number
SCANA CORPORATION	57-0784499

Number, street, and room or suite no. If a P.O. box, see instructions.

220 OPERATION WAY

City or town, state, and ZIP code

CAYCE, SC 29033-3701

Part I Overpayment Credits, Estimated Tax Payments, and Tax Deposits (see instructions)

Corp. No.	Name and address of corporation	Employer identification number	Portion of overpayment credits and estimated tax payments	Portion of tax deposited with Form 7004
	Common parent corporation			
	Subsidiary corporations:			
8	SERVICECARE INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-1007394		
9	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 220 OPERATION WAY CAYCE, SC 29033-3701	56-2128483		
10	CLEAN ENERGY ENTERPRISES INC 220 OPERATION WAY CAYCE, SC 29033-3701	56-1078443		
11	PSNC BLUE RIDGE CORPORATION 220 OPERATION WAY CAYCE, SC 29033-3701	56-1791764		
12	PSNC CARDINAL PIPELINE COMPANY 220 OPERATION WAY CAYCE, SC 29033-3701	56-1955423		
13	SCANA CORPORATE SECURITY SERVICES INC 220 OPERATION WAY CAYCE, SC 29033-3701	20-0989017		
	Totals (Must equal amounts shown on the consolidated tax return.) . . . . ▶			

Part II Principal Business Activity, Voting Stock Information, Etc. (see instructions)

Corp. No.	Principal business activity (PBA)	PBA Code No.	Did the subsidiary make any nondividend distributions? Yes	No	Stock holdings at beginning of year: Number of shares	Percentage of voting power	Percentage of value	Owned by corporation no.
	Common parent corporation							
	Subsidiary corporations:							
8	SERVICES	811412		X	1,000	100.00 %	100.00 %	1
9	NATURAL GAS DISTRIBUTION	221210		X	1,000	100.00 %	100.00 %	1
10	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00 %	9
11	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00 %	9
12	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00 %	9
13	SERVICES	541990		X	1,000	100.00 %	100.00 %	1

Part III **Changes in Stock Holdings During the Tax Year**

Corp. No.	Name of corporation	Share-holder of Corpora-tion No.	Date of transaction	(a) Changes		(b) Shares held after changes described in column (a)	
				Number of shares acquired	Number of shares disposed of	Percentage of voting power	Percentage of value
8	SERVICECARE INC	1	12/20/2016		1,000	%	%
						%	%
						%	%
						%	%
						%	%
						%	%
						%	%
						%	%

(c) If any transaction listed above caused a transfer of a share of subsidiary stock (defined to include dispositions and deconsolidations), did the share's basis exceed its value at the time of the transfer? See instructions . . . . ☐ **Yes** ☒ **No**

(d) Did any share of subsidiary stock become worthless within the meaning of section 165 (taking into account the provisions of Regulations section 1.1502-80(c)) during the taxable year? See instructions . . . . . . ☐ **Yes** ☒ **No**

(e) If the equitable owners of any capital stock shown above were other than the holders of record, provide details of the changes.

(f) If additional stock was issued, or if any stock was retired during the year, list the dates and amounts of these transactions.

Part IV Additional Stock Information (see instructions)

1 During the tax year, did the corporation have more than one class of stock outstanding? . . . . [X] **Yes** [ ] **No**

If "Yes," enter the name of the corporation and list and describe each class of stock.

Corp. No.	Name of corporation	Class of stock
3	SOUTH CAROLINA ELECTRIC and GAS COMPANY	COMMON AND PREFERRED 1000 SHS

2 During the tax year, was there any member of the consolidated group that reaffiliated within 60 months of disaffiliation? . . . . [ ] **Yes** [X] **No**

If "Yes," enter the name of the corporation(s) and explain the circumstances.

Corp. No.	Name of corporation	Explanation

3 During the tax year, was there any arrangement in existence by which one or more persons that were not members of the affiliated group could acquire any stock, or acquire any voting power without acquiring stock, in the corporation, other than a de minimis amount, from the corporation or another member of the affiliated group? . . . . [ ] **Yes** [X] **No**

If "Yes," enter the name of the corporation and see the instructions for the percentages to enter in columns (a), (b), and (c).

Corp. No.	Name of corporation	**(a)** Percentage of value	**(b)** Percentage of outstanding voting stock	**(c)** Percentage of voting power
		%	%	%
		%	%	%
		%	%	%
		%	%	%

Corp. No.	**(d)** Provide a description of any arrangement.

SCHEDULE D (Form 1120)

Department of the Treasury
Internal Revenue Service

Capital Gains and Losses

▶ Attach to Form 1120, 1120-C, 1120-F, 1120-FSC, 1120-H, 1120-IC-DISC, 1120-L, 1120-ND, 1120-PC, 1120-POL, 1120-REIT, 1120-RIC, 1120-SF, or certain Forms 990-T.

▶ Information about Schedule D (Form 1120) and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name: SCANA CORPORATION

Employer identification number: 57-0784499

Part I Short-Term Capital Gains and Losses - Assets Held One Year or Less

See instructions for how to figure the amounts to enter on the lines below. This form may be easier to complete if you round off cents to whole dollars.	(d) Proceeds (sales price)	(e) Cost (or other basis)	(g) Adjustments to gain or loss from Form(s) 8949, Part I, line 2, column (g)	(h) Gain or (loss) Subtract column (e) from column (d) and combine the result with column (g)
1a Totals for all short-term transactions reported on Form 1099-B for which basis was reported to the IRS and for which you have no adjustments (see instructions). However, if you choose to report all these transactions on Form 8949, leave this line blank and go to line 1b				
1b Totals for all transactions reported on Form(s) 8949 with **Box A** checked				
2 Totals for all transactions reported on Form(s) 8949 with **Box B** checked				
3 Totals for all transactions reported on Form(s) 8949 with **Box C** checked	28,933.	33,912.		-4,979.

4 Short-term capital gain from installment sales from Form 6252, line 26 or 37	4	
5 Short-term capital gain or (loss) from like-kind exchanges from Form 8824	5	
6 Unused capital loss carryover (attach computation)	6	( )
7 Net short-term capital gain or (loss). Combine lines 1a through 6 in column h	7	-4,979.

Part II Long-Term Capital Gains and Losses - Assets Held More Than One Year

See instructions for how to figure the amounts to enter on the lines below. This form may be easier to complete if you round off cents to whole dollars.	(d) Proceeds (sales price)	(e) Cost (or other basis)	(g) Adjustments to gain or loss from Form(s) 8949, Part II, line 2, column (g)	(h) Gain or (loss) Subtract column (e) from column (d) and combine the result with column (g)
8a Totals for all long-term transactions reported on Form 1099-B for which basis was reported to the IRS and for which you have no adjustments (see instructions). However, if you choose to report all these transactions on Form 8949, leave this line blank and go to line 8b				
8b Totals for all transactions reported on Form(s) 8949 with **Box D** checked				
9 Totals for all transactions reported on Form(s) 8949 with **Box E** checked				
10 Totals for all transactions reported on Form(s) 8949 with **Box F** checked	1,197,187.	1,119,842.		77,345.

11 Enter gain from Form 4797, line 7 or 9	11	
12 Long-term capital gain from installment sales from Form 6252, line 26 or 37	12	
13 Long-term capital gain or (loss) from like-kind exchanges from Form 8824	13	
14 Capital gain distributions (see instructions) See Statement 50	14	158,428.
15 Net long-term capital gain or (loss). Combine lines 8a through 14 in column h	15	235,773.

Part III Summary of Parts I and II

16 Enter excess of net short-term capital gain (line 7) over net long-term capital loss (line 15)	16	
17 Net capital gain. Enter excess of net long-term capital gain (line 15) over net short-term capital loss (line 7)	17	230,794.
18 Add lines 16 and 17. Enter here and on Form 1120, page 1, line 8, or the proper line on other returns. If the corporation has qualified timber gain, also complete Part IV	18	230,794.

Note: If losses exceed gains, see **Capital losses** in the instructions.

Form **8949**

Department of the Treasury
Internal Revenue Service

Sales and Other Dispositions of Capital Assets

▶ Information about Form 8949 and its separate instructions is at *www.irs.gov/form8949.*

▶ File with your Schedule D to list your transactions for lines 1b, 2, 3, 8b, 9, and 10 of Schedule D.

OMB No. 1545-0074

2016

Attachment Sequence No. **12A**

Name(s) shown on return	Social security number or taxpayer identification number
SCANA CORPORATION	57-0784499

Before you check Box A, B, or C below, see whether you received any Form(s) 1099-B or substitute statement(s) from your broker. A substitute statement will have the same information as Form 1099-B. Either will show whether your basis (usually your cost) was reported to the IRS by your broker and may even tell you which box to check.

Part I **Short-Term.** Transactions involving capital assets you held 1 year or less are short term. For long-term transactions, see page 2.

Note: You may aggregate all short-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS and for which no adjustments or codes are required. Enter the totals directly on Schedule D, line 1a; you aren't required to report these transactions on Form 8949 (see instructions).

You *must* check Box A, B, *or* C below. Check only one box. If more than one box applies for your short-term transactions, complete a separate Form 8949, page 1, for each applicable box. If you have more short-term transactions than will fit on this page for one or more of the boxes, complete as many forms with the same box checked as you need.

☐ **(A)** Short-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS (see **Note** above)
☐ **(B)** Short-term transactions reported on Form(s) 1099-B showing basis **wasn't** reported to the IRS
☒ **(C)** Short-term transactions not reported to you on Form 1099-B

1 (a) Description of property (Example: 100 sh. XYZ Co.)	(b) Date acquired (Mo., day, yr.)	(c) Date sold or disposed of (Mo., day, yr.)	(d) Proceeds (sales price) (see instructions)	(e) Cost or other basis. See the **Note** below and see *Column (e)* in the separate instructions	Adjustment, if any, to gain or loss. If you enter an amount in column (g), enter a code in column (f). **See the separate instructions.** (f) Code(s) from instructions	(g) Amount of adjustment	(h) Gain or (loss). Subtract column (e) from column (d) and combine the result with column (g)
EDCP SHORT TERM	04/20/2015	01/25/2016	28,933.	33,912.			-4,979.
2 Totals. Add the amounts in columns (d), (e), (g), and (h) (subtract negative amounts). Enter each total here and include on your Schedule D, **line 1b** (if **Box A** above is checked), **line 2** (if **Box B** above is checked), or **line 3** (if **Box C** above is checked) ▶			28,933.	33,912.			-4,979.

Note: If you checked Box A above but the basis reported to the IRS was incorrect, enter in column (e) the basis as reported to the IRS, and enter an adjustment in column (g) to correct the basis. See *Column (g)* in the separate instructions for how to figure the amount of the adjustment.

Form 8949 (2016) Attachment Sequence No. **12A** Page **2**

Name(s) shown on return. Name and SSN or taxpayer identification no. not required if shown on other side	**Social security number or taxpayer identification number**
SCANA CORPORATION	57-0784499

Before you check Box D, E, or F below, see whether you received any Form(s) 1099-B or substitute statement(s) from your broker. A substitute statement will have the same information as Form 1099-B. Either will show whether your basis (usually your cost) was reported to the IRS by your broker and may even tell you which box to check.

Part II **Long-Term.** Transactions involving capital assets you held more than 1 year are long term. For short-term transactions, see page 1.

Note: You may aggregate all long-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS and for which no adjustments or codes are required. Enter the totals directly on Schedule D, line 8a; you aren't required to report these transactions on Form 8949 (see instructions).

You *must* check Box D, E, *or* F below. Check only one box. If more than one box applies for your long-term transactions, complete a separate Form 8949, page 2, for each applicable box. If you have more long-term transactions than will fit on this page for one or more of the boxes, complete as many forms with the same box checked as you need.

☐ **(D)** Long-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS (see **Note** above)
☐ **(E)** Long-term transactions reported on Form(s) 1099-B showing basis **wasn't** reported to the IRS
☒ **(F)** Long-term transactions not reported to you on Form 1099-B

1 (a) Description of property (Example: 100 sh. XYZ Co.)	(b) Date acquired (Mo., day, yr.)	(c) Date sold or disposed (Mo., day, yr.)	(d) Proceeds (sales price) (see instructions)	(e) Cost or other basis. See the **Note** below and see *Column (e)* in the separate instructions	Adjustment, if any, to gain or loss. If you enter an amount in column (g), enter a code in column (f). **See the separate instructions.** (f) Code(s) from instructions	(g) Amount of adjustment	(h) **Gain or (loss).** Subtract column (e) from column (d) and combine the result with column (g)
EDCP LONG TERM	02/05/2014	01/25/2016	979,243.	901,898.			77,345.
TIMBER SALES	VARIOUS		217,944.	217,944.			NONE
2 Totals. Add the amounts in columns (d), (e), (g), and (h) (subtract negative amounts). Enter each total here and include on your Schedule D, **line 8b** (if **Box D** above is checked), **line 9** (if **Box E** above is checked), or **line 10** (if **Box F** above is checked) ▶			1,197,187.	1,119,842.			77,345.

Note: If you checked Box D above but the basis reported to the IRS was incorrect, enter in column (e) the basis as reported to the IRS, and enter an adjustment in column (g) to correct the basis. See *Column (g)* in the separate instructions for how to figure the amount of the adjustment.

SCHEDULE M-3 (Form 1120)

Department of the Treasury
Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ Attach to Form 1120 or 1120-C. ▶ Information about Schedule M-3 (Form 1120) and its separate instructions is available at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) ☐ Non-consolidated return (2) ☒ Consolidated return (Form 1120 only)
(3) ☐ Mixed 1120/L/PC group (4) ☐ Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
☒ **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
☐ **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
☐ **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
☐ **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
☐ **Yes.** Complete lines 2a through 11 with respect to that income statement.
☐ **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 01/01/2016 Ending 12/31/2016

b Has the corporation's income statement been restated for the income statement period on line 2a?
☐ **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
☒ **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
☐ **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
☒ **No.**

3 a Is any of the corporation's voting common stock publicly traded?
☒ **Yes.**
☐ **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock . . . . SCG

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock 80589M102

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	4a	594,849,551.
b	Indicate accounting standard used for line 4a (see instructions): (1) ☒ GAAP (2) ☐ IFRS (3) ☐ Statutory (4) ☐ Tax-basis (5) ☐ Other (specify)		
5 a	Net income from nonincludible foreign entities (attach statement)	5a	( )
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount)	5b	
6 a	Net income from nonincludible U.S. entities (attach statement)	6a	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	6b	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	7a	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement)	7b	
c	Net income (loss) of other includible entities (attach statement)	7c	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	8	
9	Adjustment to reconcile income statement period to tax year (attach statement)	9	
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	10a	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	10b	
c	Other adjustments to reconcile to amount on line 11 (attach statement)	10c	
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	11	594,849,551.

Note. Part I, line 11, must equal Part II, line 30, column (a) or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

	Total Assets	Total Liabilities
a Included on Part I, line 4 ▶	18,706,879,069.	12,981,847,721.
b Removed on Part I, line 5 ▶		
c Removed on Part I, line 6 ▶		
d Included on Part I, line 7 ▶		

Schedule M-3 (Form 1120) 2016 Page **2**

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed		34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	3,751,723.	954,029.		4,705,752.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	-2,299,688.	-1,380,838.		-3,680,526.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	40,236,868.	201,001,590.		241,238,458.
14 Total accrual to cash adjustment				
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(2,169,000,078.)	72,440,739.		(2,096,559,339.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	566,889.	-566,889.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities		235,773.		235,773.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-4,979.		-4,979.
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-51,771,917.		-51,771,917.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement) Stmt 53	4,348,156,767.	24,580,638.	222,694.	4,372,960,099.
26 **Total income (loss) items.** Combine lines 1 through 25	2,200,042,197.	245,574,517.	222,694.	2,445,839,408.
27 **Total expense/deduction items** (from Part III, line 38)	-1,613,822,773.	-1,114,100,827.	216,554,237.	-2,511,369,363.
28 Other items with no differences	8,630,127.	Stmt 54		8,630,127.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	594,849,551.	-868,526,310.	216,776,931.	-56,899,828.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	594,849,551.	-868,526,310.	216,776,931.	-56,899,828.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)

Employer identification number

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	35,319,589.		-35,319,589.	
2 U.S. deferred income tax expense	201,531,407.		-201,531,407.	
3 State and local current income tax expense	12,961,624.	-11,298,538.		1,663,086.
4 State and local deferred income tax expense	20,908,859.	-20,908,859.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	342,269,370.	42,908,253.		385,177,623.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	2,833,057.		-1,501,983.	1,331,074.
12 Fines and penalties	-346,594.		346,594.	
13 Judgments, damages, awards, and similar costs	9,343,483.	-2,378,759.		6,964,724.
14 Parachute payments				
15 Compensation with section 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.
16 Pension and profit-sharing	24,499,724.	-23,804,767.		694,957.
17 Other post-retirement benefits	61,069,682.	-4,266,874.		56,802,808.
18 Deferred compensation Stmt 60	4,528,916.	-4,528,916.		
19 Charitable contribution of cash and tangible property	3,083,562.	497,595.	4,582.	3,585,739.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	4,391,015.	7,212,662.		11,603,677.
29 Reserved				
30 Depletion				
31 Depreciation	352,117,080.	322,789,444.		674,906,524.
32 Bad debt expense	10,931,132.	-583,897.		10,347,235.
33 Corporate owned life insurance premiums	-624,899.		624,899.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs Stmt 60		722,622,385.		722,622,385.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement) Stmt 61	511,355,651.	85,841,098.	26,913,688.	624,110,437.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,613,822,773.	1,114,100,827.	-216,554,237.	2,511,369,363.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) ☐ Consolidated group (2) ☐ Parent corp (3) ☐ Consolidated eliminations (4) ☒ Subsidiary corp (5) ☐ Mixed 1120/L/PC group

Check if a sub-consolidated: (6) ☐ 1120 group (7) ☐ 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed		34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations	612,397,274.		-612,397,274.	
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities		-33,798.		-33,798.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	9,922,963.	-1,366,405.		8,556,558.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities		235,773.		235,773.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-4,979.		-4,979.
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	622,320,237.	-831,917.	-612,397,274.	9,091,046.
27 **Total expense/deduction items** (from Part III, line 38)	-28,096,287.	6,603,298.	-53,237,447.	-74,730,436.
28 Other items with no differences	-136,909.			-136,909.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	594,087,041.	5,771,381.	-665,634,721.	-65,776,299.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	594,087,041.	5,771,381.	-665,634,721.	-65,776,299.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-21,613,000.		21,613,000.	
2 U.S. deferred income tax expense	-3,623,000.		3,623,000.	
3 State and local current income tax expense	-3,261,300.	3,261,300.		
4 State and local deferred income tax expense	-544,700.	544,700.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	54,743,724.	-3,597.		54,740,127.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	170,908.		-170,908.	
12 Fines and penalties	-350,900.		350,900.	
13 Judgments, damages, awards, and similar costs		44,555.		44,555.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	481,120.	-1,983,346.		-1,502,226.
17 Other post-retirement benefits	-49,835.	-2,846,314.		-2,896,149.
18 Deferred compensation	4,528,916.	-4,528,916.		
19 Charitable contribution of cash and tangible property		145.		145.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums	-662,284.		662,284.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	-1,723,362.	-1,091,825.	27,159,171.	24,343,984.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	28,096,287.	-6,603,298.	53,237,447.	74,730,436.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA SERVICES INC
Employer identification number: 57-1092169

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	730,796.			730,796.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(74,318,188.)			(74,318,188.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-696,096.		-696,096.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	-73,587,392.	-696,096.		-74,283,488.
27 **Total expense/deduction items** (from Part III, line 38)	-228,778,968.	11,381,801.		-217,397,167.
28 Other items with no differences	302,366,360.			302,366,360.
29a Mixed groups, see instructions. All others, combine lines 26 through 28		10,685,705.		10,685,705.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c		10,685,705.		10,685,705.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA SERVICES INC

Employer identification number: 57-1092169

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	5,064,100.		-5,064,100.	
2 U.S. deferred income tax expense	-5,064,100.		5,064,100.	
3 State and local current income tax expense	848,600.	-838,600.		10,000.
4 State and local deferred income tax expense	-848,600.	848,600.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	9,119,174.			9,119,174.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	5,113,014.	-522,071.		4,590,943.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	364,871.			364,871.
17 Other post-retirement benefits	29,670,928.			29,670,928.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	3,396,707.	-1,257,589.		2,139,118.
29 Reserved				
30 Depletion				
31 Depreciation	12,610,493.	3,229,767.		15,840,260.
32 Bad debt expense	57,907.			57,907.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		882,125.		882,125.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	168,445,874.	-13,724,033.		154,721,841.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	228,778,968.	-11,381,801.		217,397,167.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA ELECTRIC and GAS COMPANY

Employer identification number: 57-0248695

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	-3,486,238.	-1,347,040.		-4,833,278.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	32,004,614.	203,397,097.		235,401,711.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(1,104,945,601.)	16,634,798.		(1,088,310,803.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	621,436.	-621,436.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-38,024,208.		-38,024,208.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	2,974,321,805.	24,317,336.	60,389.	2,998,699,530.
26 **Total income (loss) items.** Combine lines 1 through 25	1,898,516,016.	204,356,547.	60,389.	2,102,932,952.
27 **Total expense/deduction items** (from Part III, line 38)	-1,155,512,001.	-959,826,350.	212,981,318.	-1,902,357,033.
28 Other items with no differences	-230,312,531.			-230,312,531.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	512,691,484.	-755,469,803.	213,041,707.	-29,736,612.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	512,691,484.	-755,469,803.	213,041,707.	-29,736,612.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA ELECTRIC and GAS COMPANY

Employer identification number: 57-0248695

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	45,571,465.		-45,571,465.	
2 U.S. deferred income tax expense	163,658,014.		-163,658,014.	
3 State and local current income tax expense	11,734,524.	-11,734,524.		
4 State and local deferred income tax expense	19,251,854.	-19,251,854.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	254,693,671.	42,604,735.		297,298,406.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	2,002,874.		-1,001,437.	1,001,437.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	7,729,228.	-1,922,201.		5,807,027.
14 Parachute payments				
15 Compensation with section 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.
16 Pension and profit-sharing	20,973,512.	-19,604,703.		1,368,809.
17 Other post-retirement benefits	44,703,978.	-1,089,215.		43,614,763.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	2,255,999.	478,374.	2,177.	2,736,550.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs		8,116,771.		8,116,771.
29 Reserved				
30 Depletion				
31 Depreciation	268,849,610.	163,071,582.		431,921,192.
32 Bad debt expense	6,625,659.	-275,701.		6,349,958.
33 Corporate owned life insurance premiums	28,544.		-28,544.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		721,608,322.		721,608,322.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	289,782,954.	77,824,764.	-218,753.	367,388,965.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,155,512,001.	959,826,350.	-212,981,318.	1,902,357,033.

Schedule M-3 (Form 1120) 2016 Page **2**

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) ☐ Consolidated group (2) ☐ Parent corp (3) ☐ Consolidated eliminations (4) ☒ Subsidiary corp (5) ☐ Mixed 1120/L/PC group

Check if a sub-consolidated: (6) ☐ 1120 group (7) ☐ 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SOUTH CAROLINA FUEL CO INC	57-0691209

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(235,135,917.)	55,780,868.		(179,355,049.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	-235,135,917.	55,780,868.		-179,355,049.
27 **Total expense/deduction items** (from Part III, line 38)	-1,846,341.	-46,060,920.		-47,907,261.
28 Other items with no differences	236,982,258.			236,982,258.
29a Mixed groups, see instructions. All others, combine lines 26 through 28		9,719,948.		9,719,948.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c		9,719,948.		9,719,948.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): **(1)** ☐ Consolidated group **(2)** ☐ Parent corp **(3)** ☐ Consolidated eliminations **(4)** ☒ Subsidiary corp **(5)** ☐ Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** ☐ 1120 group **(7)** ☐ 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA FUEL CO INC

Employer identification number: 57-0691209

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	**(a)** Expense per Income Statement	**(b)** Temporary Difference	**(c)** Permanent Difference	**(d)** Deduction per Tax Return
1 U.S. current income tax expense	3,232,500.		-3,232,500.	
2 U.S. deferred income tax expense	-3,232,500.		3,232,500.	
3 State and local current income tax expense	486,100.	-486,100.		
4 State and local deferred income tax expense	-486,100.	486,100.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	1,845,292.			1,845,292.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	11.			11.
17 Other post-retirement benefits	1,038.			1,038.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation		46,060,920.		46,060,920.
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,846,341.	46,060,920.		47,907,261.

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Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SC GENERATING COMPANY INC	57-0784498

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	54,046.	-31,785.		22,261.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(113,725,200.)			(113,725,200.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-3,530,135.		-3,530,135.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	-113,671,154.	-3,561,920.		-117,233,074.
27 **Total expense/deduction items** (from Part III, line 38)	-55,762,783.	-6,888,802.	6,916,462.	-55,735,123.
28 Other items with no differences	182,523,825.			182,523,825.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	13,089,888.	-10,450,722.	6,916,462.	9,555,628.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	13,089,888.	-10,450,722.	6,916,462.	9,555,628.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SC GENERATING COMPANY INC

Employer identification number: 57-0784498

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	1,526,840.		-1,526,840.	
2 U.S. deferred income tax expense	5,390,460.		-5,390,460.	
3 State and local current income tax expense	344,200.	-344,200.		
4 State and local deferred income tax expense	803,400.	-803,400.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	15,345,851.	-482,617.		14,863,234.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	744.		-372.	372.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	177,603.	20,908.		198,511.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	19,491.			19,491.
17 Other post-retirement benefits	1,568,904.			1,568,904.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	10,012.		2,405.	12,417.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	139,749.	-37,956.		101,793.
29 Reserved				
30 Depletion				
31 Depreciation	18,359,883.	1,230,464.		19,590,347.
32 Bad debt expense				
33 Corporate owned life insurance premiums	1,195.		-1,195.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	12,074,451.	7,305,603.		19,380,054.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	55,762,783.	6,888,802.	-6,916,462.	55,735,123.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA COMMUNICATIONS HOLDINGS INC

Employer identification number: 51-0394908

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	1,186,550.			1,186,550.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	6,321.			6,321.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	1,192,871.			1,192,871.
27 **Total expense/deduction items** (from Part III, line 38)	-410,284.		410,284.	
28 Other items with no differences	-20,631.			-20,631.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	761,956.		410,284.	1,172,240.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	761,956.		410,284.	1,172,240.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	410,284.		-410,284.	
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	410,284.		-410,284.	

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Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SCANA ENERGY MARKETING INC	57-0850977

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	374,179.			374,179.
14 Total accrual to cash adjustment				
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(812,053,946.)	-77,007.		(812,130,953.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	1,646.	-1,646.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		1,646.		1,646.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	938,014,128.	263,302.		938,277,430.
26 **Total income (loss) items.** Combine lines 1 through 25	104,965,723.	-64,826.		104,900,897.
27 **Total expense/deduction items** (from Part III, line 38)	-49,810,799.	2,042,244.	16,396,483.	-31,372,072.
28 Other items with no differences	-25,341,670.			-25,341,670.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	29,813,254.	1,977,418.	16,396,483.	48,187,155.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	29,813,254.	1,977,418.	16,396,483.	48,187,155.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA ENERGY MARKETING INC

Employer identification number: 57-0850977

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	15,814,300.		-15,814,300.	
2 U.S. deferred income tax expense	382,600.		-382,600.	
3 State and local current income tax expense	2,385,200.	-1,128,598.		1,256,602.
4 State and local deferred income tax expense	32,200.	-32,200.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	1,070,855.			1,070,855.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	384,040.		-192,020.	192,020.
12 Fines and penalties	4,306.		-4,306.	
13 Judgments, damages, awards, and similar costs	77,812.	3,175.		80,987.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	1,007,820.	-954,780.		53,040.
17 Other post-retirement benefits	4,442,895.	-121,580.		4,321,315.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	446,898.	6,536.		453,434.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	854,559.	244,088.		1,098,647.
29 Reserved				
30 Depletion				
31 Depreciation	237,169.	718,134.		955,303.
32 Bad debt expense	3,837,358.	-408,199.		3,429,159.
33 Corporate owned life insurance premiums	3,257.		-3,257.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		131,938.		131,938.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	18,829,530.	-500,758.		18,328,772.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	49,810,799.	-2,042,244.	-16,396,483.	31,372,072.

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SERVICECARE INC	57-1007394

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	**(a)** Income (Loss) per Income Statement	**(b)** Temporary Difference	**(c)** Permanent Difference	**(d)** Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	5,863.			5,863.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	5,863.			5,863.
27 **Total expense/deduction items** (from Part III, line 38)	10,393.	-1,168,109.	-8,400.	-1,166,116.
28 Other items with no differences	-31,927.			-31,927.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-15,671.	-1,168,109.	-8,400.	-1,192,180.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	-15,671.	-1,168,109.	-8,400.	-1,192,180.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SERVICECARE INC	57-1007394

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-401,900.		401,900.	
2 U.S. deferred income tax expense	393,500.		-393,500.	
3 State and local current income tax expense	-60,400.	60,400.		
4 State and local deferred income tax expense	59,000.	-59,000.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs		3,709.		3,709.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing		849,150.		849,150.
17 Other post-retirement benefits		313,850.		313,850.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense	-593.			-593.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-10,393.	1,168,109.	8,400.	1,166,116.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORTATED

Employer identification number: 56-2128483

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	6,572,645.	-1,013,022.		5,559,623.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(205,178,315.)	102,080.		(205,076,235.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	-56,193.	56,193.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-9,523,124.		-9,523,124.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	435,820,834.		162,305.	435,983,139.
26 **Total income (loss) items.** Combine lines 1 through 25	237,158,971.	-10,377,873.	162,305.	226,943,403.
27 **Total expense/deduction items** (from Part III, line 38)	-147,379,356.	-119,881,825.	28,136,365.	-239,124,816.
28 Other items with no differences	-35,495,924.			-35,495,924.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	54,283,691.	-130,259,698.	28,298,670.	-47,677,337.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	54,283,691.	-130,259,698.	28,298,670.	-47,677,337.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): **(1)** ☐ Consolidated group **(2)** ☐ Parent corp **(3)** ☐ Consolidated eliminations **(4)** ☒ Subsidiary corp **(5)** ☐ Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** ☐ 1120 group **(7)** ☐ 1120 eliminations

Name of subsidiary (if consolidated return): PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORTATED

Employer identification number: 56-2128483

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	**(a)** Expense per Income Statement	**(b)** Temporary Difference	**(c)** Permanent Difference	**(d)** Deduction per Tax Return
1 U.S. current income tax expense	-15,947,900.		15,947,900.	
2 U.S. deferred income tax expense	43,915,900.		-43,915,900.	
3 State and local current income tax expense	328,400.	-29,985.		298,415.
4 State and local deferred income tax expense	3,002,200.	-3,002,200.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	25,177,074.	789,732.		25,966,806.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	274,491.		-137,246.	137,245.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	1,358,840.	-6,834.		1,352,006.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	2,017,770.	-2,111,088.		-93,318.
17 Other post-retirement benefits	10,402,702.	-523,615.		9,879,087.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	370,653.	12,540.		383,193.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs		147,348.		147,348.
29 Reserved				
30 Depletion				
31 Depreciation	52,059,925.	108,478,577.		160,538,502.
32 Bad debt expense	468,708.	100,003.		568,711.
33 Corporate owned life insurance premiums	4,389.		-4,389.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	23,946,204.	16,027,347.	-26,730.	39,946,821.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	147,379,356.	119,881,825.	-28,136,365.	239,124,816.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): CLEAN ENERGY ENTERPRISES INC

Employer identification number: 56-1078443

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 38)	400.		-400.	
28 Other items with no differences	-1,703.			-1,703.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-1,303.		-400.	-1,703.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	-1,303.		-400.	-1,703.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): CLEAN ENERGY ENTERPRISES INC

Employer identification number: 56-1078443

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-400.		400.	
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-400.		400.	

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PSNC BLUE RIDGE CORPORATION

Employer identification number: 56-1791764

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	1,138,536.	476,903.		1,615,439.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)		3,557.		3,557.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	1,138,536.	480,460.		1,618,996.
27 **Total expense/deduction items** (from Part III, line 38)	-361,751.	-89,746.	411,026.	-40,471.
28 Other items with no differences	-10,900.			-10,900.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	765,885.	390,714.	411,026.	1,567,625.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	765,885.	390,714.	411,026.	1,567,625.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PSNC BLUE RIDGE CORPORATION

Employer identification number: 56-1791764

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	**(a)** Expense per Income Statement	**(b)** Temporary Difference	**(c)** Permanent Difference	**(d)** Deduction per Tax Return
1 U.S. current income tax expense	507,200.		-507,200.	
2 U.S. deferred income tax expense	-96,174.		96,174.	
3 State and local current income tax expense	68,200.	-27,729.		40,471.
4 State and local deferred income tax expense	-117,475.	117,475.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	361,751.	89,746.	-411,026.	40,471.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PSNC CARDINAL PIPELINE COMPANY

Employer identification number: 56-1955423

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	2,613,187.	477,126.		3,090,313.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)		12,148.		12,148.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	2,613,187.	489,274.		3,102,461.
27 **Total expense/deduction items** (from Part III, line 38)	-807,987.	-212,418.	962,807.	-57,598.
28 Other items with no differences	-34,600.			-34,600.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	1,770,600.	276,856.	962,807.	3,010,263.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	1,770,600.	276,856.	962,807.	3,010,263.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PSNC CARDINAL PIPELINE COMPANY

Employer identification number: 56-1955423

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	1,156,100.		-1,156,100.	
2 U.S. deferred income tax expense	-193,293.		193,293.	
3 State and local current income tax expense	88,100.	-30,502.		57,598.
4 State and local deferred income tax expense	-242,920.	242,920.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	807,987.	212,418.	-962,807.	57,598.

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SCANA CORPORATE SECURITY SERVICES INC	20-0989017

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 38)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28				
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c				

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SCANA CORPORATE SECURITY SERVICES INC	20-0989017

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive				

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Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [X] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
ELIMINATIONS SCANA CORPORATIO	

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations	-612,397,274.		612,397,274.	
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	-9,434,559.			-9,434,559.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(-376,357,089.)			(-376,357,089.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	-245,474,744.		612,397,274.	366,922,530.
27 **Total expense/deduction items** (from Part III, line 38)	54,932,991.			54,932,991.
28 Other items with no differences	-421,855,521.			-421,855,521.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-612,397,274.		612,397,274.	
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	-612,397,274.		612,397,274.	

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [X] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): ELIMINATIONS SCANA CORPORATIO

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	-19,726,271.			-19,726,271.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	-5,113,014.			-5,113,014.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	-364,871.			-364,871.
17 Other post-retirement benefits	-29,670,928.			-29,670,928.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense	-57,907.			-57,907.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-54,932,991.			-54,932,991.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) Consolidated group (2) Parent corp (3) Consolidated eliminations (4) Subsidiary corp (5) Mixed 1120/L/PC group

Check if a sub-consolidated: (6) 1120 group (7) 1120 eliminations

Name of subsidiary (if consolidated return): Adjustments

Employer identification number

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 38)			3,585,739.	3,585,739.
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28			3,585,739.	3,585,739.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c			3,585,739.	3,585,739.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

JSA
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Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) ☐ Consolidated group (2) ☐ Parent corp (3) ☐ Consolidated eliminations (4) ☐ Subsidiary corp (5) ☐ Mixed 1120/L/PC group

Check if a sub-consolidated: (6) ☐ 1120 group (7) ☐ 1120 eliminations

Name of subsidiary (if consolidated return): Adjustments

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive			-3,585,739.	-3,585,739.

SCHEDULE UTP (Form 1120)

Department of the Treasury
Internal Revenue Service

Uncertain Tax Position Statement

▶ **File with Form 1120, 1120-F, 1120-L, or 1120-PC.**

▶ **Information about Schedule UTP (Form 1120) and its separate instructions is at *www.irs.gov/scheduleutp*.**

OMB No. 1545-0123

2016

Name of entity as shown on page 1 of tax return: SCANA CORPORATION

EIN of entity: 57-0784499

This Part I, Schedule UTP (Form 1120) is page 1 of 1 Part I pages.

Part I **Uncertain Tax Positions for the Current Tax Year.** See instructions for how to complete columns (a) through (g). Enter, in Part III, a description for each uncertain tax position (UTP).

Check this box if the corporation was unable to obtain information from related parties sufficient to determine whether a tax position is a UTP. See instructions. ▶ ☐

(a) UTP No.	(b) Primary IRC Sections (for example, "61", "108", "263A") / Primary IRC Subsections (for example, (f)(2)(A)(ii))			(c) Timing Codes (check if Permanent, Temporary, or both)		(d) Pass-Through Entity EIN	(e) Major Tax Position	(f) Ranking of Tax Position	(g) Reserved for Future Use
C1	41(a)			P ☒	T ☐		☒	G2	
C2	174			P ☐	T ☒		☒	G1	
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		

Name of entity as shown on page 1 of tax return	EIN of entity
SCANA CORPORATION	57-0784499

This Part II, Schedule UTP (Form 1120) is page 1 of 1 Part II pages.

Part II **Uncertain Tax Positions for Prior Tax Years.**
See instructions for how to complete columns (a) through (h). Enter, in Part III, a description for each uncertain tax position (UTP).

Check this box if the corporation was unable to obtain information from related parties sufficient to determine whether a tax position is a UTP. See instructions. ▶ ☐

(a) UTP No.	(b) Primary IRC Sections (for example, "61", "108", "263A") / Primary IRC Subsections (for example, (f)(2)(A)(ii))			(c) Timing Codes (check if Permanent, Temporary, or both)		(d) Pass-Through Entity EIN	(e) Major Tax Position	(f) Ranking of Tax Position	(g) Reserved for Future Use	(h) Year of Tax Position
P 3	41(a)			P X	T		X	G4		2015-12
P 4	41(a)			P X	T		X	G4		2014-12
P 5	41(a)			P X	T		X	G4		2013-12
P 6	41(a)			P X	T		X	G4		2012-12
P 7	41(a)			P X	T		X	G4		2011-12
P 8	41(a)			P X	T		X	G4		2010-12
P 9	41(a)			P X	T		X	G4		2009-12
P 10	41(a)			P X	T		X	G4		2008-12
P 11	174			P	T X		X	G3		2015-12
P 12	174			P	T X		X	G3		2014-12
P 13	174			P	T X		X	G3		2013-12
P 14	174			P	T X		X	G3		2012-12
P 15	174			P	T X		X	G3		2011-12
P 16	174			P	T X		X	G3		2010-12
P 17	174			P	T X		X	G3		2009-12
P 18	174			P	T X		X	G3		2008-12
P				P	T					
P				P	T					
P				P	T					
P				P	T					
P				P	T					

Name of entity as shown on page 1 of tax return: SCANA CORPORATION
EIN of entity: 57-0784499

This Part III, Schedule UTP (Form 1120) is page 1 of 3 Part III pages.

Part III **Concise Descriptions of UTPs.** Indicate the corresponding UTP number from Part I, column (a) (for example, C1) or Part II column (a) (for example, P2). Use as many Part III pages as necessary. See instructions.

UTP No.	Concise Description of Uncertain Tax Position
C1	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
C2	The taxpayer claimed deductions for research expenses related to its nuclear facility. The issues are whether adequate documentation has been retained to substantiate the deductions claimed and whether the expenses constitute research expenses. This position is based on the final regulations as issued under Treasury Regulation Sec 1.174-2.
P3	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
P4	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
P5	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
P6	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation

Name of entity as shown on page 1 of tax return	EIN of entity
SCANA CORPORATION	57-0784499

This Part III, Schedule UTP (Form 1120) is page 2 of 3 Part III pages.

Part III **Concise Descriptions of UTPs.** Indicate the corresponding UTP number from Part I, column (a) (for example, C1) or Part II column (a) (for example, P2). Use as many Part III pages as necessary. See instructions.

UTP No.	Concise Description of Uncertain Tax Position
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P7	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P8	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P9	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P10	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P11	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P12	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under

Name of entity as shown on page 1 of tax return: SCANA CORPORATION

EIN of entity: 57-0784499

This Part III, Schedule UTP (Form 1120) is page 3 of 3 Part III pages.

Part III **Concise Descriptions of UTPs.** Indicate the corresponding UTP number from Part I, column (a) (for example, C1) or Part II column (a) (for example, P2). Use as many Part III pages as necessary. See instructions.

UTP No.	Concise Description of Uncertain Tax Position
	Treasury Regulation Sec 1.174-2.
P13	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P14	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P15	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P16	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P17	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P18	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.

Form **966** (Rev. October 2016)
Department of the Treasury
Internal Revenue Service

Corporate Dissolution or Liquidation

(Required under section 6043(a) of the Internal Revenue Code)
▶ Information about Form 966 and its instructions is at *www.irs.gov/form966.*

OMB No. 1545-0123

Please type or print

Name of corporation: SERVICECARE INC	**Employer identification number**: 57-1007394
Number, street, and room or suite no. (If a P.O. box number, see instructions.): 220 OPERATION WAY	Check type of return: [X] 1120 [ ] 1120-L [ ] 1120-IC-DISC [ ] 1120S [ ] Other ▶
City or town, state, and ZIP code: CAYCE SC 29033-3701	

1 Date incorporated: 09/20/1994	**2** Place incorporated: SOUTH CAROLINA	**3** Type of liquidation: [X] Complete [ ] Partial	**4** Date resolution or plan of complete or partial liquidation was adopted: 12/20/2016
5 Service Center where corporation filed its immediately preceding tax return: efile	**6** Last month, day, and year of immediately preceding tax year: 12/31/2015	**7a** Last month, day, and year of final tax year: 12/31/2016	**7b** Was corporation's final tax return filed as part of a consolidated income tax return? If "Yes," complete 7c, 7d, and 7e. [X] Yes [ ] No
7c Name of common parent: SCANA CORPORATION		**7d** Employer identification number of common parent: 57-0784499	**7e** Service Center where consolidated return was filed: efile

	Common	Preferred
8 Total number of shares outstanding at time of adoption of plan of liquidation	1,000.	
9 Date(s) of any amendments to plan of dissolution		
10 Section of the Code under which the corporation is to be dissolved or liquidated	332	
11 If this form concerns an amendment or supplement to a resolution or plan, enter the date the previous Form 966 was filed		

Attach a certified copy of the resolution or plan and all amendments or supplements not previously filed.

Under penalties of perjury, I declare that I have examined this form, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete.

Signature of officer	Title	Date
▶	CONTROLLER	

Instructions

Section references are to the Internal Revenue Code unless otherwise noted.

Who Must File

A corporation (or a farmer's cooperative) must file Form 966 if it adopts a resolution or plan to dissolve the corporation or liquidate any of its stock.

Exempt organizations and qualified subchapter S subsidiaries should not file Form 966. Exempt organizations should see the instructions for Form 990, Return of Organization Exempt From Income Tax, or Form 990-PF, Return of Private Foundation or Section 4947(a)(1) Trust Treated as Private Foundation. Subchapter S subsidiaries should see Form 8869, Qualified Subchapter S Subsidiary Election.

! CAUTION *Do not file Form 966 for a deemed liquidation (such as a section 338 election or an election to be treated as a disregarded entity under Regulations section 301.7701-3).*

When To File

File Form 966 within 30 days after the resolution or plan is adopted to dissolve the corporation or liquidate any of its stock. If the resolution or plan is amended or supplemented after Form 966 is filed, file another Form 966 within 30 days after the amendment or supplement is adopted. The additional form will be sufficient if the date the earlier form was filed is entered on line 11 and a certified copy of the amendment or supplement is attached. Include all information required by Form 966 that was not given in the earlier form.

Where To File

File Form 966 with the Internal Revenue Service Center at the address where the corporation (or cooperative) files its income tax return.

Distribution of Property

A corporation must recognize gain or loss on the distribution of its assets in the complete liquidation of its stock. For purposes of determining gain or loss, the

Form **1125-A**
(Rev. October 2016)
Department of the Treasury
Internal Revenue Service

Cost of Goods Sold

▶ **Attach to Form 1120, 1120-C, 1120-F, 1120S, 1065, or 1065-B.**
▶ **Information about Form 1125-A and its instructions is at *www.irs.gov/form1125a.***

OMB No. 1545-0123

Name: SCANA CORPORATION

Employer identification number: 57-0784499

1	Inventory at beginning of year	1	311,778,910.
2	Purchases	2	730,665,983.
3	Cost of labor	3	-429,280.
4	Additional section 263A costs (attach schedule)	4	
5	Other costs (attach schedule) See Statement 67	5	1,366,645,976.
6	**Total.** Add lines 1 through 5	6	2,408,661,589.
7	Inventory at end of year	7	290,480,845.
8	**Cost of goods sold.** Subtract line 7 from line 6. Enter here and on Form 1120, page 1, line 2 or the appropriate line of your tax return. See instructions	8	2,118,180,744.

9a Check all methods used for valuing closing inventory:

(i) ☐ Cost

(ii) ☐ Lower of cost or market

(iii) ☒ Other (Specify method used and attach explanation.) ▶ WEIGHTED AVERAGE

b Check if there was a writedown of subnormal goods ▶ ☐

c Check if the LIFO inventory method was adopted this tax year for any goods (if checked, attach Form 970) ▶ ☐

d If the LIFO inventory method was used for this tax year, enter amount of closing inventory computed under LIFO **9d**

e If property is produced or acquired for resale, do the rules of section 263A apply to the entity? See instructions ☒ Yes ☐ No

f Was there any change in determining quantities, cost, or valuations between opening and closing inventory? If "Yes," attach explanation ☐ Yes ☒ No

Section references are to the Internal Revenue Code unless otherwise noted.

General Instructions

Purpose of Form

Use Form 1125-A to calculate and deduct cost of goods sold for certain entities.

Who Must File

Filers of Form 1120, 1120-C, 1120-F, 1120S, 1065, or 1065-B, must complete and attach Form 1125-A if the applicable entity reports a deduction for cost of goods sold.

Inventories

Generally, inventories are required at the beginning and end of each tax year if the production, purchase, or sale of merchandise is an income-producing factor. See Regulations section 1.471-1. If inventories are required, you generally must use an accrual method of accounting for sales and purchases of inventory items.

Exception for certain taxpayers. If you are a qualifying taxpayer or a qualifying small business taxpayer (defined below), you can adopt or change your accounting method to account for inventoriable items in the same manner as materials and supplies that are not incidental.

Under this accounting method, inventory costs for raw materials purchased for use in producing finished goods and merchandise purchased for resale are deductible in the year the finished goods or merchandise are sold (but not before the year you paid for the raw materials or merchandise, if you are also using the cash method).

If you account for inventoriable items in the same manner as materials and supplies that are not incidental, you can currently deduct expenditures for direct labor and all indirect costs that would otherwise be included in inventory costs. See the instructions for lines 2 and 7.

For additional guidance on this method of accounting, see Pub. 538, Accounting Periods and Methods. For guidance on adopting or changing to this method of accounting, see Form 3115, Application for Change in Accounting Method, and its instructions.

Qualifying taxpayer. A qualifying taxpayer is a taxpayer that, (a) for each prior tax year ending after December 16, 1998, has average annual gross receipts of $1 million or less for the 3 prior tax years, and (b) its business is not a tax shelter (as defined in section 448(d)(3)). See Rev. Proc. 2001-10, 2001-2 I.R.B. 272.

Qualifying small business taxpayer. A qualifying small business taxpayer is a taxpayer that, (a) for each prior tax year ending on or after December 31, 2000, has average annual gross receipts of $10 million or less for the 3 prior tax years, (b) whose principal business activity is not an ineligible activity, and (c) whose business is not a tax shelter (as defined in section 448 (d)(3)). See Rev. Proc. 2002-28, 2002-18 I.R.B. 815.

Uniform capitalization rules. The uniform capitalization rules of section 263A generally require you to capitalize, or include in inventory, certain costs incurred in connection with the following.

- The production of real property and tangible personal property held in inventory or held for sale in the ordinary course of business.
- Real property or personal property (tangible and intangible) acquired for resale.
- The production of real property and tangible personal property by a corporation for use in its trade or business or in an activity engaged in for profit.

See the discussion on section 263A uniform capitalization rules in the instructions for your tax return before completing Form 1125-A. Also see Regulations sections 1.263A-1 through 1.263A-3. See Regulations section 1.263A-4 for rules for property produced in a farming business.

Form **1125-E**
(Rev. October 2016)
Department of the Treasury
Internal Revenue Service

Compensation of Officers

▶ Attach to Form 1120, 1120-C, 1120-F, 1120-REIT, 1120-RIC, or 1120S.
▶ Information about Form 1125-E and its separate instructions is at *www.irs.gov/form1125e*.

OMB No. 1545-0123

Name: SCANA CORPORATION

Employer identification number: 57-0784499

Note: Complete Form 1125-E only if total receipts are $500,000 or more. See instructions for definition of total receipts.

	(a) Name of officer	(b) Social security number (see instructions)	(c) Percent of time devoted to business	Percent of stock owned (d) Common	Percent of stock owned (e) Preferred	(f) Amount of compensation
1			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	
			%	%	%	

2	Total compensation of officers	2	15,144,833.
3	Compensation of officers claimed on Form 1125-A or elsewhere on return	3	
4	Subtract line 3 from line 2. Enter the result here and on Form 1120, page 1, line 12 or the appropriate line of your tax return . . . See Statement 69	4	15,144,833.

For Paperwork Reduction Act Notice, see separate instructions.

JSA
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Form **3800**

Department of the Treasury
Internal Revenue Service (99)

General Business Credit

▶ Information about Form 3800 and its separate instructions is at *www.irs.gov/form3800*.
▶ You must attach all pages of Form 3800, pages 1, 2, and 3, to your tax return.

OMB No. 1545-0895
2016
Attachment Sequence No. 22

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Part I Current Year Credit for Credits Not Allowed Against Tentative Minimum Tax (TMT)
(See instructions and complete Part(s) III before Parts I and II)

1	General business credit from line 2 of all Parts III with box A checked	1	28,148,334.
2	Passive activity credits from line 2 of all Parts III with box B checked — 2		
3	Enter the applicable passive activity credits allowed for 2016 (see instructions)	3	
4	Carryforward of general business credit to 2016. Enter the amount from line 2 of Part III with box C checked. See instructions for statement to attach	4	
5	Carryback of general business credit from 2017. Enter the amount from line 2 of Part III with box D checked (see instructions)	5	
6	Add lines 1, 3, 4, and 5	6	28,148,334.

Part II Allowable Credit

7	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46, or the sum of the amounts from Form 1040NR, lines 42 and 44 • Corporations. Enter the amount from Form 1120, Schedule J, Part I, line 2; or the applicable line of your return • Estates and trusts. Enter the sum of the amounts from Form 1041, Schedule G, lines 1a and 1b; or the amount from the applicable line of your return	7	
8	Alternative minimum tax: • Individuals. Enter the amount from Form 6251, line 35 • Corporations. Enter the amount from Form 4626, line 14 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 56	8	
9	Add lines 7 and 8	9	
10a	Foreign tax credit — 10a		
b	Certain allowable credits (see instructions) — 10b		
c	Add lines 10a and 10b	10c	
11	**Net income tax.** Subtract line 10c from line 9. If zero, skip lines 12 through 15 and enter -0- on line 16	11	
12	**Net regular tax.** Subtract line 10c from line 7. If zero or less, enter -0- — 12		
13	Enter 25% (.25) of the excess, if any, of line 12 over $25,000 (see instructions) — 13		
14	Tentative minimum tax: • Individuals. Enter the amount from Form 6251, line 33 • Corporations. Enter the amount from Form 4626, line 12 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 54 — 14		
15	Enter the greater of line 13 or line 14	15	
16	Subtract line 15 from line 11. If zero or less, enter -0-	16	
17	Enter the **smaller** of line 6 or line 16 **C corporations:** See the line 17 instructions if there has been an ownership change, acquisition, or reorganization.	17	

Part II **Allowable Credit** *(Continued)*

Note: If you are not required to report any amounts on lines 22 or 24 below, skip lines 18 through 25 and enter -0- on line 26.

18	Multiply line 14 by 75% (.75) (see instructions)	18	
19	Enter the greater of line 13 or line 18	19	
20	Subtract line 19 from line 11. If zero or less, enter -0-	20	
21	Subtract line 17 from line 20. If zero or less, enter -0-	21	
22	Combine the amounts from line 3 of all Parts III with box A, C, or D checked	22	
23	Passive activity credit from line 3 of all Parts III with box B checked — 23		
24	Enter the applicable passive activity credit allowed for 2016 (see instructions)	24	
25	Add lines 22 and 24	25	
26	Empowerment zone and renewal community employment credit allowed. Enter the smaller of line 21 or line 25	26	
27	Subtract line 13 from line 11. If zero or less, enter -0-	27	
28	Add lines 17 and 26	28	
29	Subtract line 28 from line 27. If zero or less, enter -0-	29	
30	Enter the general business credit from line 5 of all Parts III with box A checked	30	8,254,946.
31	Reserved	31	
32	Passive activity credits from line 5 of all Parts III with box B checked — 32		
33	Enter the applicable passive activity credits allowed for 2016 (see instructions)	33	
34	Carryforward of business credit to 2016. Enter the amount from line 5 of Part III with box C checked and line 6 of Part III with box G checked. See instructions for statement to attach	34	
35	Carryback of business credit from 2017. Enter the amount from line 5 of Part III with box D checked (see instructions)	35	
36	Add lines 30, 33, 34, and 35	36	8,254,946.
37	Enter the **smaller** of line 29 or line 36	37	
38	**Credit allowed for the current year.** Add lines 28 and 37. Report the amount from line 38 (if smaller than the sum of Part I, line 6, and Part II, lines 25 and 36, see instructions) as indicated below or on the applicable line of your return: • Individuals. Form 1040, line 54, or Form 1040NR, line 51 • Corporations. Form 1120, Schedule J, Part I, line 5c • Estates and trusts. Form 1041, Schedule G, line 2b	38	

Form 3800 (2016) Page **3**

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part III **General Business Credits or Eligible Small Business Credits** (see instructions)

Complete a separate Part III for each box checked below (see instructions).

A	X	General Business Credit From a Non-Passive Activity	E		Reserved
B		General Business Credit From a Passive Activity	F		Reserved
C		General Business Credit Carryforwards	G		Eligible Small Business Credit Carryforwards
D		General Business Credit Carrybacks	H		Reserved

I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III ▶ ☐

	(a) Description of credit **Note:** On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		28,145,407.
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel (carryforward only)	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance (carryforward only)	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		2,927.
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other. Enhanced oil recovery (Form 8830) and certain other credits	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		28,148,334.
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		8,254,946.
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Increasing research activities (Form 6765)	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		8,254,946.
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		36,403,280.

Form **4562** | Department of the Treasury Internal Revenue Service (99)

Depreciation and Amortization

(Including Information on Listed Property)

▶ Attach to your tax return.

▶ Information about Form 4562 and its separate instructions is at *www.irs.gov/form4562*.

OMB No. 1545-0172

2016

Attachment Sequence No. 179

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Business or activity to which this form relates: General Depreciation & Amortization

Part I Election To Expense Certain Property Under Section 179

Note: If you have any listed property, complete Part V before you complete Part I.

1	Maximum amount (see instructions)	1	
2	Total cost of section 179 property placed in service (see instructions)	2	
3	Threshold cost of section 179 property before reduction in limitation (see instructions)	3	
4	Reduction in limitation. Subtract line 3 from line 2. If zero or less, enter -0-	4	
5	Dollar limitation for tax year. Subtract line 4 from line 1. If zero or less, enter -0-. If married filing separately, see instructions	5	

6	(a) Description of property	(b) Cost (business use only)	(c) Elected cost

7	Listed property. Enter the amount from line 29	7	
8	Total elected cost of section 179 property. Add amounts in column (c), lines 6 and 7	8	
9	Tentative deduction. Enter the **smaller** of line 5 or line 8	9	
10	Carryover of disallowed deduction from line 13 of your 2015 Form 4562	10	
11	Business income limitation. Enter the smaller of business income (not less than zero) or line 5 (see instructions)	11	
12	Section 179 expense deduction. Add lines 9 and 10, but don't enter more than line 11	12	
13	Carryover of disallowed deduction to 2017. Add lines 9 and 10, less line 12 ▶	13	

Note: Don't use Part II or Part III below for listed property. Instead, use Part V.

Part II Special Depreciation Allowance and Other Depreciation (Don't include listed property.) (See instructions.)

14	Special depreciation allowance for qualified property (other than listed property) placed in service during the tax year (see instructions)	14	309,573,587.
15	Property subject to section 168(f)(1) election	15	
16	Other depreciation (including ACRS)	16	2,616,055.

Part III MACRS Depreciation (Don't include listed property.) (See instructions.)

Section A

17	MACRS deductions for assets placed in service in tax years beginning before 2016	17	347,024,206.
18	If you are electing to group any assets placed in service during the tax year into one or more general asset accounts, check here ▶ ☐		

Section B - Assets Placed in Service During 2016 Tax Year Using the General Depreciation System

(a) Classification of property	(b) Month and year placed in service	(c) Basis for depreciation (business/investment use only - see instructions)	(d) Recovery period	(e) Convention	(f) Method	(g) Depreciation deduction
19a 3-year property						
b 5-year property		9,822,207.	5.000	HY	200 DB	1,964,443.
c 7-year property		13,156,047.	7.000	HY	200 DB	1,879,486.
d 10-year property						
e 15-year property		126,315,695.	15.000	HY	150 DB	6,315,785.
f 20-year property		147,377,601.	20.000	HY	150 DB	5,527,192.
g 25-year property			25 yrs.		S/L	
h Residential rental property			27.5 yrs.	MM	S/L	
			27.5 yrs.	MM	S/L	
i Nonresidential real property		450,159.	39 yrs.	MM	S/L	5,770.
				MM	S/L	

Section C - Assets Placed in Service During 2016 Tax Year Using the Alternative Depreciation System

20a Class life					S/L	
b 12-year			12 yrs.		S/L	
c 40-year			40 yrs.	MM	S/L	

Part IV Summary (See instructions.)

21	Listed property. Enter amount from line 28	21	
22	**Total.** Add amounts from line 12, lines 14 through 17, lines 19 and 20 in column (g), and line 21. Enter here and on the appropriate lines of your return. Partnerships and S corporations - see instructions	22	674,906,524.
23	For assets shown above and placed in service during the current year, enter the portion of the basis attributable to section 263A costs	23	

Part V **Listed Property** (Include automobiles, certain other vehicles, certain aircraft, certain computers, and property used for entertainment, recreation, or amusement.)

Note: For any vehicle for which you are using the standard mileage rate or deducting lease expense, complete **only** 24a, 24b, columns (a) through (c) of Section A, all of Section B, and Section C if applicable.

Section A - Depreciation and Other Information (Caution: See the instructions for limits for passenger automobiles.**)**

24a Do you have evidence to support the business/investment use claimed? ☐ Yes ☐ No **24b** If "Yes," is the evidence written? ☐ Yes ☐ No

(a) Type of property (list vehicles first)	(b) Date placed in service	(c) Business/ investment use percentage	(d) Cost or other basis	(e) Basis for depreciation (business/investment use only)	(f) Recovery period	(g) Method/ Convention	(h) Depreciation deduction	(i) Elected section 179 cost
25 Special depreciation allowance for qualified listed property placed in service during the tax year and used more than 50% in a qualified business use (see instructions)						25		
26 Property used more than 50% in a qualified business use:								
		%						
		%						
		%						
27 Property used 50% or less in a qualified business use:								
		%				S/L -		
		%				S/L -		
		%				S/L -		
28 Add amounts in column (h), lines 25 through 27. Enter here and on line 21, page 1						28		
29 Add amounts in column (i), line 26. Enter here and on line 7, page 1							29	

Section B - Information on Use of Vehicles

Complete this section for vehicles used by a sole proprietor, partner, or other "more than 5% owner," or related person. If you provided vehicles to your employees, first answer the questions in Section C to see if you meet an exception to completing this section for those vehicles.

	(a) Vehicle 1		(b) Vehicle 2		(c) Vehicle 3		(d) Vehicle 4		(e) Vehicle 5		(f) Vehicle 6	
30 Total business/investment miles driven during the year (**don't** include commuting miles)												
31 Total commuting miles driven during the year												
32 Total other personal (noncommuting) miles driven												
33 Total miles driven during the year. Add lines 30 through 32												
	Yes	**No**	**Yes**	**No**	**Yes**	**No**	**Yes**	**No**	**Yes**	**No**	**Yes**	**No**
34 Was the vehicle available for personal use during off-duty hours?												
35 Was the vehicle used primarily by a more than 5% owner or related person?												
36 Is another vehicle available for personal use?												

Section C - Questions for Employers Who Provide Vehicles for Use by Their Employees

Answer these questions to determine if you meet an exception to completing Section B for vehicles used by employees who **aren't** more than 5% owners or related persons (see instructions).

	Yes	**No**
37 Do you maintain a written policy statement that prohibits all personal use of vehicles, including commuting, by your employees?		
38 Do you maintain a written policy statement that prohibits personal use of vehicles, except commuting, by your employees? See the instructions for vehicles used by corporate officers, directors, or 1% or more owners		
39 Do you treat all use of vehicles by employees as personal use?		
40 Do you provide more than five vehicles to your employees, obtain information from your employees about the use of the vehicles, and retain the information received?		
41 Do you meet the requirements concerning qualified automobile demonstration use? (See instructions.)		

Note: If your answer to 37, 38, 39, 40, or 41 is "Yes," don't complete Section B for the covered vehicles.

Part VI **Amortization**

(a) Description of costs	(b) Date amortization begins	(c) Amortizable amount	(d) Code section	(e) Amortization period or percentage	(f) Amortization for this year
42 Amortization of costs that begins during your 2016 tax year (see instructions):					
				Total	2,067,441.
43 Amortization of costs that began before your 2016 tax year				43	9,536,236.
44 **Total.** Add amounts in column (f). See the instructions for where to report				44	11,603,677.

Form **4797**

Department of the Treasury
Internal Revenue Service

Sales of Business Property

(Also Involuntary Conversions and Recapture Amounts Under Sections 179 and 280F(b)(2))

► **Attach to your tax return.**

► **Information about Form 4797 and its separate instructions is at *www.irs.gov/form4797*.**

OMB No. 1545-0184

2016

Attachment Sequence No. **27**

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

1	Enter the gross proceeds from sales or exchanges reported to you for 2016 on Form(s) 1099-B or 1099-S (or substitute statement) that you are including on line 2, 10, or 20. See instructions	1	

Part I **Sales or Exchanges of Property Used in a Trade or Business and Involuntary Conversions From Other Than Casualty or Theft - Most Property Held More Than 1 Year** (see instructions)

2 (a) Description of property	(b) Date acquired (mo., day, yr.)	(c) Date sold (mo., day, yr.)	(d) Gross sales price	(e) Depreciation allowed or allowable since acquisition	(f) Cost or other basis, plus improvements and expense of sale	(g) Gain or (loss) Subtract (f) from the sum of (d) and (e)
Stmt 76						-53,778,949.

3	Gain, if any, from Form 4684, line 39	3	
4	Section 1231 gain from installment sales from Form 6252, line 26 or 37	4	
5	Section 1231 gain or (loss) from like-kind exchanges from Form 8824	5	
6	Gain, if any, from line 32, from other than casualty or theft	6	
7	Combine lines 2 through 6. Enter the gain or (loss) here and on the appropriate line as follows:	7	-53,778,949.
	Partnerships (except electing large partnerships) and S corporations. Report the gain or (loss) following the instructions for Form 1065, Schedule K, line 10, or Form 1120S, Schedule K, line 9. Skip lines 8, 9, 11, and 12 below.		
	Individuals, partners, S corporation shareholders, and all others. If line 7 is zero or a loss, enter the amount from line 7 on line 11 below and skip lines 8 and 9. If line 7 is a gain and you didn't have any prior year section 1231 losses, or they were recaptured in an earlier year, enter the gain from line 7 as a long-term capital gain on the Schedule D filed with your return and skip lines 8, 9, 11, and 12 below.		
8	Nonrecaptured net section 1231 losses from prior years. See instructions	8	
9	Subtract line 8 from line 7. If zero or less, enter -0-. If line 9 is zero, enter the gain from line 7 on line 12 below. If line 9 is more than zero, enter the amount from line 8 on line 12 below and enter the gain from line 9 as a long-term capital gain on the Schedule D filed with your return. See instructions	9	

Part II **Ordinary Gains and Losses** (see instructions)

10 Ordinary gains and losses not included on lines 11 through 16 (include property held 1 year or less):

Stmt 81						-1,782,435.

11	Loss, if any, from line 7	11	(53,778,949.)
12	Gain, if any, from line 7 or amount from line 8, if applicable	12	
13	Gain, if any, from line 31	13	3,789,467.
14	Net gain or (loss) from Form 4684, lines 31 and 38a	14	
15	Ordinary gain from installment sales from Form 6252, line 25 or 36	15	
16	Ordinary gain or (loss) from like-kind exchanges from Form 8824	16	
17	Combine lines 10 through 16	17	-51,771,917.
18	For all except individual returns, enter the amount from line 17 on the appropriate line of your return and skip lines a and b below. For individual returns, complete lines a and b below:		
a	If the loss on line 11 includes a loss from Form 4684, line 35, column (b)(ii), enter that part of the loss here. Enter the part of the loss from income-producing property on Schedule A (Form 1040), line 28, and the part of the loss from property used as an employee on Schedule A (Form 1040), line 23. Identify as from "Form 4797, line 18a." See instructions	18a	
b	Redetermine the gain or (loss) on line 17 excluding the loss, if any, on line 18a. Enter here and on Form 1040, line 14	18b	

Part III Gain From Disposition of Property Under Sections 1245, 1250, 1252, 1254, and 1255 (see instructions)

19 (a) Description of section 1245, 1250, 1252, 1254, or 1255 property:	(b) Date acquired (mo., day, yr.)	(c) Date sold (mo., day, yr.)
A VARIOUS		
B Various	VARIOUS	VARIOUS
C		
D		

These columns relate to the properties on lines 19A through 19D. ▶		Property A	Property B	Property C	Property D
20 Gross sales price (**Note:** *See line 1 before completing.*)	20	3,145,850.	819,826.		
21 Cost or other basis plus expense of sale	21	9,970,544.	1,713,829.		
22 Depreciation (or depletion) allowed or allowable	22	9,807,650.	1,700,514.		
23 Adjusted basis. Subtract line 22 from line 21	23	162,894.	13,315.		
24 Total gain. Subtract line 23 from line 20	24	2,982,956.	806,511.		
25 **If section 1245 property:**					
a Depreciation allowed or allowable from line 22	25a	9,807,650.	1,700,514.		
b Enter the **smaller** of line 24 or 25a	25b	2,982,956.	806,511.		
26 **If section 1250 property:** If straight line depreciation was used, enter -0- on line 26g, except for a corporation subject to section 291.					
a Additional depreciation after 1975. See instructions	26a				
b Applicable percentage multiplied by the **smaller** of line 24 or line 26a. See instructions	26b				
c Subtract line 26a from line 24. If residential rental property **or** line 24 isn't more than line 26a, skip lines 26d and 26e	26c				
d Additional depreciation after 1969 and before 1976	26d				
e Enter the **smaller** of line 26c or 26d	26e				
f Section 291 amount (corporations only)	26f				
g Add lines 26b, 26e, and 26f	26g				
27 **If section 1252 property:** Skip this section if you didn't dispose of farmland or if this form is being completed for a partnership (other than an electing large partnership).					
a Soil, water, and land clearing expenses	27a				
b Line 27a multiplied by applicable percentage. See instructions	27b				
c Enter the **smaller** of line 24 or 27b	27c				
28 **If section 1254 property:**					
a Intangible drilling and development costs, expenditures for development of mines and other natural deposits, mining exploration costs, and depletion. See instructions	28a				
b Enter the **smaller** of line 24 or 28a	28b				
29 **If section 1255 property:**					
a Applicable percentage of payments excluded from income under section 126. See instructions	29a				
b Enter the **smaller** of line 24 or 29a. See instructions	29b				

Summary of Part III Gains. Complete property columns A through D through line 29b before going to line 30.

30 Total gains for all properties. Add property columns A through D, line 24	30	3,789,467.
31 Add property columns A through D, lines 25b, 26g, 27c, 28b, and 29b. Enter here and on line 13	31	3,789,467.
32 Subtract line 31 from line 30. Enter the portion from casualty or theft on Form 4684, line 33. Enter the portion from other than casualty or theft on Form 4797, line 6	32	

Part IV Recapture Amounts Under Sections 179 and 280F(b)(2) When Business Use Drops to 50% or Less (see instructions)

		(a) Section 179	(b) Section 280F(b)(2)
33 Section 179 expense deduction or depreciation allowable in prior years	33		
34 Recomputed depreciation. See instructions	34		
35 Recapture amount. Subtract line 34 from line 33. See the instructions for where to report	35		

Form **6765**

Department of the Treasury
Internal Revenue Service

Credit for Increasing Research Activities

▶ Attach to your tax return.

▶ Information about Form 6765 and its separate instructions is at *www.irs.gov/form6765*.

OMB No. 1545-0619

2016

Attachment Sequence No. 81

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Section A - Regular Credit. Skip this section and go to Section B if you are electing or previously elected (and are not revoking) the alternative simplified credit.

Line	Description	Box	Amount	Box	Amount
1	Certain amounts paid or incurred to energy consortia (see instructions)			1	1,723,298.
2	Basic research payments to qualified organizations (see instructions)	2			
3	Qualified organization base period amount	3			
4	Subtract line 3 from line 2. If zero or less, enter -0-			4	
5	Wages for qualified services (do not include wages used in figuring the work opportunity credit)	5	2,585,567.		
6	Cost of supplies	6	9,839,450.		
7	Rental or lease costs of computers (see instructions)	7			
8	Enter the applicable percentage of contract research expenses (see instructions)	8	417,134,646.		
9	Total qualified research expenses. Add lines 5 through 8	9	429,559,663.		
10	Enter fixed-base percentage, but not more than 16% (0.16) (see instructions)	10	0.030 %		
11	Enter average annual gross receipts (see instructions)	11	5,039,022,108.		
12	Multiply line 11 by the percentage on line 10	12	1,511,707.		
13	Subtract line 12 from line 9. If zero or less, enter -0-	13	428,047,956.		
14	Multiply line 9 by 50% (0.50)	14	214,779,832.		
15	Enter the **smaller** of line 13 or line 14			15	214,779,832.
16	Add lines 1, 4, and 15			16	216,503,130.
17	Are you electing the reduced credit under section 280C? ▶ Yes [X] No [ ] If "Yes," multiply line 16 by 13% (0.13). If "No," multiply line 16 by 20% (0.20) and see the instructions for the statement that must be attached. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached Stmt 84			17	28,145,407.

Section B - Alternative Simplified Credit. Skip this section if you are completing Section A.

Line	Description	Box	Amount	Box	Amount
18	Certain amounts paid or incurred to energy consortia (see the line 1 instructions)			18	
19	Basic research payments to qualified organizations (see the line 2 instructions)	19			
20	Qualified organization base period amount (see the line 3 instructions)	20			
21	Subtract line 20 from line 19. If zero or less, enter -0-			21	
22	Add lines 18 and 21			22	
23	Multiply line 22 by 20% (0.20)			23	
24	Wages for qualified services (do not include wages used in figuring the work opportunity credit)	24			
25	Cost of supplies	25			
26	Rental or lease costs of computers (see the line 7 instructions)	26			
27	Enter the applicable percentage of contract research expenses (see the line 8 instructions)	27			
28	Total qualified research expenses. Add lines 24 through 27	28			
29	Enter your total qualified research expenses for the prior 3 tax years. If you had no qualified research expenses in any one of those years, skip lines 30 and 31	29			
30	Divide line 29 by 6.0	30			
31	Subtract line 30 from line 28. If zero or less, enter -0-	31			
32	Multiply line 31 by 14% (0.14). If you skipped lines 30 and 31, multiply line 28 by 6% (0.06)			32	

For Paperwork Reduction Act Notice, see separate instructions.

Section B - Alternative Simplified Credit *(continued)*

33	Add lines 23 and 32	33	
34	Are you electing the reduced credit under section 280C? ▶ Yes ☐ No ☐ If "Yes," multiply line 33 by 65% (0.65). If "No," enter the amount from line 33 and see the line 17 instructions for the statement that must be attached. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached	34	

Section C - Current Year Credit

35	Enter the portion of the credit from Form 8932, line 2, that is attributable to wages that were also used to figure the credit on line 17 or line 34 (whichever applies)	35	
36	Subtract line 35 from line 17 or line 34 (whichever applies). If zero or less, enter -0-	36	28,145,407.
37	Credit for increasing research activities from partnerships, S corporations, estates, and trusts	37	
38	Add lines 36 and 37	38	28,145,407.
	• Estates and trusts, go to line 39. • Partnerships and S corporations not electing the payroll tax credit, stop here and report this amount on Schedule K. • Partnerships and S corporations electing the payroll tax credit, complete Section D and report on Schedule K the amount on this line reduced by the amount on line 44. • Eligible small businesses, stop here and report the credit on Form 3800, Part III, line 4i. See instructions for the definition of eligible small business. • Filers other than eligible small businesses, stop here and report the credit on Form 3800, Part III, line 1c. **Note:** Qualified small business filers, other than partnerships and S corporations, electing the payroll tax credit must complete Form 3800 before completing Section D.		
39	Amount allocated to beneficiaries of the estate or trust (see instructions)	39	
40	Estates and trusts, subtract line 39 from line 38. For eligible small businesses, report the credit on Form 3800, Part III, line 4i. See instructions. For filers other than eligible small businesses, report the credit on Form 3800, Part III, line 1c	40	

Section D - Qualified Small Business Payroll Tax Election and Payroll Tax Credit. Skip this section if the payroll tax election does not apply. See instructions.

41	Check this box if you are a qualified small business electing the payroll tax credit. See instructions ☐		
42	Enter the portion of line 36 elected as a payroll tax credit (do not enter more than $250,000). See instructions	42	
43	General business credit carryforward from the current year (see instructions). Partnerships and S corporations skip this line and go to line 44	43	
44	Partnerships and S corporations, enter the smaller of line 36 or line 42. All others, enter the smallest of line 36, line 42, or line 43. Enter here and on Form 8974, line 5. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached	44	

Form **7004**
(Rev. December 2016)
Department of the Treasury
Internal Revenue Service

Application for Automatic Extension of Time To File Certain Business Income Tax, Information, and Other Returns

▶ File a separate application for each return.
▶ Information about Form 7004 and its separate instructions is at *www.irs.gov/form7004.*

OMB No. 1545-0233

Print or Type

Name: SCANA CORPORATION
Identifying number: 57-0784499
Number, street, and room or suite no. (If P.O. box, see instructions.): 220 OPERATION WAY
City, town, state, and ZIP code (If a foreign address, enter city, province or state, and country (follow the country's practice for entering postal code)).: CAYCE, SC 29033-3701

Note: File request for extension by the due date of the return for which the extension is granted. See instructions before completing this form.

Part I Automatic Extension for C Corporations With Tax Years Ending December 31. See instructions.

1a Enter the form code for the return listed below that this application is for 1 2

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part II Automatic Extension for Certain Estates and Trusts. See instructions.

b Enter the form code for the return listed below that this application is for . . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1041 (estate other than a bankruptcy estate)	04	Form 1041 (trust)	05

Part III Automatic Extension for Entities Not Using Part I, II, or IV. See instructions.

c Enter the form code for the return listed below that this application is for . . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 706-GS(D)	01	Form 1120-ND (section 4951 taxes)	20
Form 706-GS(T)	02	Form 1120-PC	21
Form 1041 (bankruptcy estate only)	03	Form 1120-POL	22
Form 1041-N	06	Form 1120-REIT	23
Form 1041-QFT	07	Form 1120-RIC	24
Form 1042	08	Form 1120S	25
Form 1065	09	Form 1120-SF	26
Form 1065-B	10	Form 3520-A	27
Form 1066	11	Form 8612	28
Form 1120	12	Form 8613	29
Form 1120-C	34	Form 8725	30
Form 1120-F	15	Form 8804	31
Form 1120-FSC	16	Form 8831	32
Form 1120-H	17	Form 8876	33
Form 1120-L	18	Form 8924	35
Form 1120-ND	19	Form 8928	36

Part IV Automatic Extension for C Corporations With Tax Years Ending June 30. See instructions.

d Enter the form code for the return listed below that this application is for . . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

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Part V **All Filers Must Complete This Part**

2 If the organization is a foreign corporation that does not have an office or place of business in the United States, check here . . . ▶ ☐

3 If the organization is a corporation and is the common parent of a group that intends to file a consolidated return, check here . . . ▶ ☒
If checked, attach a statement listing the name, address, and Employer Identification Number (EIN) for each member covered by this application.

4 If the organization is a corporation or partnership that qualifies under Regulations section 1.6081-5, check here . . ▶ ☐

5a The application is for calendar year 20 16 , or tax year beginning ____________ , 20 ___ , and ending ______________ , 20 ___

b **Short tax year.** If this tax year is less than 12 months, check the reason: ☐ Initial return ☐ Final return
☐ Change in accounting period ☐ Consolidated return to be filed ☐ Other (see instructions - attach explanation)

6	Tentative total tax . . .	6	6,000,000.
7	**Total** payments and credits (see instructions) . . .	7	6,000,000.
8	**Balance due.** Subtract line 7 from line 6 (see instructions) . . .	8	

Form **8082**

(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: **(a)** [X] Notice of inconsistent treatment **(b)** [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership **(b)** [ ] S corporation **(c)** [ ] Estate **(d)** [ ] Trust **(e)** [ ] REMIC

3 Employer identification number of pass-through entity
27-1302931

4 Name, address, and ZIP code of pass-through entity
CANADYS REFINED COAL LLC
TWO PIERCE PLACE
ITASCA,IL 60143

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS			-2,143,846.	-2,143,846.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082**

(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: **(a)** [X] Notice of inconsistent treatment **(b)** [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership **(b)** [ ] S corporation **(c)** [ ] Estate **(d)** [ ] Trust **(e)** [ ] REMIC

3 Employer identification number of pass-through entity
26-0468152

4 Name, address, and ZIP code of pass-through entity
APOG LLC
42 INVERNESS CENTER PARKWAY
BIRMINGHAM,AL 35242

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	**(b)** Inconsistency is in, or AAR is to correct (check boxes that apply)		**(c)** Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	**(d)** Amount you are reporting	**(e)** Difference between (c) and (d)
		Amount of item	Treatment of item			
8	ORDINARY BUSINESS INCOME/LOSS	X				
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

For Paperwork Reduction Act Notice, see separate instructions. Form **8082** (Rev. 12-2011)

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Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 45-3989987

4 Name, address, and ZIP code of pass-through entity:
BRANDON SHORES COALTECH LLC
TWO PIERCE PLACE
ITASCA,IL 60143

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	(b) Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS	X		-1,351,550.	-1,351,550.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

For Paperwork Reduction Act Notice, see separate instructions.

Form **8082** (Rev. 12-2011)

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Form **8082**

(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: **(a)** [X] Notice of inconsistent treatment **(b)** [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership **(b)** [ ] S corporation **(c)** [ ] Estate **(d)** [ ] Trust **(e)** [ ] REMIC

3 Employer identification number of pass-through entity
45-3444400

4 Name, address, and ZIP code of pass-through entity
LOUISA REFINED COAL LLC
6901 DODGE ST SUITE 201
OMAHA,NE 68132

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS			-1,371,983.	-1,371,983.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 90-1010358

4 Name, address, and ZIP code of pass-through entity:
MPH ENERGY MIDCO LP
99 RIVER ROAD
COS COB,CT 06807

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS	X		-69.	-69.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: **(a)** [X] Notice of inconsistent treatment **(b)** [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership **(b)** [ ] S corporation **(c)** [ ] Estate **(d)** [ ] Trust **(e)** [ ] REMIC

3 Employer identification number of pass-through entity
46-2244841

4 Name, address, and ZIP code of pass-through entity
REPOWER SOUTH LLC
314 SOUTH PINE STREET SUITE 200
SPARTANBURG,SC 29302

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	(b) Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS	X		-45,015.	-45,015.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 47-5603086

4 Name, address, and ZIP code of pass-through entity:
BRUNNER ISLAND REFINED COAL LLC
2850 GOLF ROAD
ROLLING MEADOWS,IL 60008

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	(b) Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS	X		-906,042.	-906,042.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082**

(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: PSNC BLUE RIDGE CORPORATION

Identifying number: 56-1791764

Part I General Information

1 Check boxes that apply: **(a)** [X] Notice of inconsistent treatment **(b)** [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership **(b)** [ ] S corporation **(c)** [ ] Estate **(d)** [ ] Trust **(e)** [ ] REMIC

3 Employer identification number of pass-through entity
76-0479579

4 Name, address, and ZIP code of pass-through entity
PINE NEEDLE LNG COMPANY LLC
ONE WILLIAMS CENTER PO BOX 2400
TULSA,OK 74102

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	**(b)** Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	**(c)** Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	**(d)** Amount you are reporting	**(e)** Difference between (c) and (d)
8	SEE ATTACHED	X		1,618,996.	1,618,996.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

PRELIMINARY K-1 RECEIVED AT TIME OF FILING

Form **8082**

(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. **84**

Name(s) shown on return: PSNC CARDINAL PIPELINE COMPANY

Identifying number: 56-1955423

Part I General Information

1 Check boxes that apply: **(a)** [X] Notice of inconsistent treatment **(b)** [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership **(b)** [ ] S corporation **(c)** [ ] Estate **(d)** [ ] Trust **(e)** [ ] REMIC

3 Employer identification number of pass-through entity
76-0489410

4 Name, address, and ZIP code of pass-through entity
CARDINAL PIPELINE COMPANY LLC
ONE WILLIAMS CENTER PO BOX 2400
TULSA,OK 74102

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	(b) Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	SEE ATTACHED	X		3,102,461.	3,102,461.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

PRELIMINARY K-1 RECEIVED AT TIME OF FILING

For Paperwork Reduction Act Notice, see separate instructions.

Form **8082** (Rev. 12-2011)

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Form **8283**
(Rev. December 2014)
Department of the Treasury
Internal Revenue Service

Noncash Charitable Contributions

▶ **Attach to your tax return if you claimed a total deduction of over $500 for all contributed property.**
▶ **Information about Form 8283 and its separate instructions is at *www.irs.gov/form8283.***

OMB No. 1545-0908
Attachment Sequence No. **155**

Name(s) shown on your income tax return	Identifying number
SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695

Note. Figure the amount of your contribution deduction before completing this form. See your tax return instructions.

Section A. Donated Property of $5,000 or Less and Publicly Traded Securities - List in this section **only** items (or groups of similar items) for which you claimed a deduction of $5,000 or less. Also, list publicly traded securities even if the deduction is more than $5,000 (see instructions).

Part I **Information on Donated Property -** If you need more space, attach a statement.

1	**(a)** Name and address of the donee organization	**(b)** If donated property is a vehicle (see instructions), check the box. Also enter the vehicle identification number (unless Form 1098-C is attached).	**(c)** Description of donated property (For a vehicle, enter the year, make, model, and mileage. For securities, enter the company name and the number of shares.)
A	[redacted]		2009 CHEVROLET
B			
C			
D			
E			

Note. If the amount you claimed as a deduction for an item is $500 or less, you do not have to complete columns (e), (f), and (g).

	(d) Date of the contribution	**(e)** Date acquired by donor (mo., yr.)	**(f)** How acquired by donor	**(g)** Donor's cost or adjusted basis	**(h)** Fair market value (see instructions)	**(i)** Method used to determine the fair market value
A	05/04/2016	2009-06	PURCHASE	3,680.	5,857.	
B						
C						
D						
E						

Part II **Partial Interests and Restricted Use Property -** Complete lines 2a through 2e if you gave less than an entire interest in a property listed in Part I. Complete lines 3a through 3c if conditions were placed on a contribution listed in Part I; also attach the required statement (see instructions).

2a Enter the letter from Part I that identifies the property for which you gave less than an entire interest ▶ ______
If Part II applies to more than one property, attach a separate statement.

b Total amount claimed as a deduction for the property listed in Part I: **(1)** For this tax year ▶ ______
(2) For any prior tax years ▶ ______

c Name and address of each organization to which any such contribution was made in a prior year (complete only if different from the donee organization above):
Name of charitable organization (donee)
Address (number, street, and room or suite no.)
City or town, state, and ZIP code

d For tangible property, enter the place where the property is located or kept ▶ ______
e Name of any person, other than the donee organization, having actual possession of the property ▶ ______

		Yes	No
3a	Is there a restriction, either temporary or permanent, on the donee's right to use or dispose of the donated property?		
b	Did you give to anyone (other than the donee organization or another organization participating with the donee organization in cooperative fundraising) the right to the income from the donated property or to the possession of the property, including the right to vote donated securities, to acquire the property by purchase or otherwise, or to designate the person having such income, possession, or right to acquire?		
c	Is there a restriction limiting the donated property for a particular use?		

Form 8283 (Rev. 12-2014) Page **2**

Name(s) shown on your income tax return	Identifying number
CALHOUN COUNTY RURAL FIRE DISTRICT SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695

Section B. Donated Property Over $5,000 (Except Publicly Traded Securities) - Complete this section for one item (or one group of similar items) for which you claimed a deduction of more than $5,000 per item or group (except contributions of publicly traded securities reported in Section A). Provide a separate form for each property donated unless it is part of a group of similar items. An appraisal is generally required for property listed in Section B. See instructions.

Part I Information on Donated Property - To be completed by the taxpayer and/or the appraiser.

4 Check the box that describes the type of property donated:

a ☐ Art* (contribution of $20,000 or more)
b ☐ Qualified Conservation Contribution
c ☐ Equipment
d ☐ Art* (contribution of less than $20,000)
e ☐ Other Real Estate
f ☐ Securities
g ☐ Collectibles**
h ☐ Intellectual Property
i ☐ Vehicles
j ☐ Other

*Art includes paintings, sculptures, watercolors, prints, drawings, ceramics, antiques, decorative arts, textiles, carpets, silver, rare manuscripts, historical memorabilia, and other similar objects.

**Collectibles include coins, stamps, books, gems, jewelry, sports memorabilia, dolls, etc., but not art as defined above.

Note. In certain cases, you must attach a qualified appraisal of the property. See instructions.

5	(a) Description of donated property (if you need more space, attach a separate statement)	(b) If tangible property was donated, give a brief summary of the overall physical condition of the property at the time of the gift	(c) Appraised fair market value
A			
B			
C			
D			

	(d) Date acquired by donor (mo., yr.)	(e) How acquired by donor	(f) Donor's cost or adjusted basis	(g) For bargain sales, enter amount received	See instructions (h) Amount claimed as a deduction	(i) Date of contribution
A						
B						
C						
D						

Part II Taxpayer (Donor) Statement - List each item included in Part I above that the appraisal identifies as having a value of $500 or less. See instructions.

I declare that the following item(s) included in Part I above has to the best of my knowledge and belief an appraised value of not more than $500 (per item). Enter identifying letter from Part I and describe the specific item. See instructions. ▶

Signature of taxpayer (donor) ▶ Date ▶

Part III Declaration of Appraiser

I declare that I am not the donor, the donee, a party to the transaction in which the donor acquired the property, employed by, or related to any of the foregoing persons, or married to any person who is related to any of the foregoing persons. And, if regularly used by the donor, donee, or party to the transaction, I performed the majority of my appraisals during my tax year for other persons.

Also, I declare that I perform appraisals on a regular basis; and that because of my qualifications as described in the appraisal, I am qualified to make appraisals of the type of property being valued. I certify that the appraisal fees were not based on a percentage of the appraised property value. Furthermore, I understand that a false or fraudulent overstatement of the property value as described in the qualified appraisal or this Form 8283 may subject me to the penalty under section 6701(a) (aiding and abetting the understatement of tax liability). In addition, I understand that I may be subject to a penalty under section 6695A if I know, or reasonably should know, that my appraisal is to be used in connection with a return or claim for refund and a substantial or gross valuation misstatement results from my appraisal. I affirm that I have not been barred from presenting evidence or testimony by the Office of Professional Responsibility.

Sign Here Signature ▶ Title ▶ Date ▶

Business address (including room or suite no.) | **Identifying number**

[redacted]

Part IV Donee Acknowledgment - To be completed by the charitable organization.

This charitable organization acknowledges that it is a qualified organization under section 170(c) and that it received the donated property as described in Section B, Part I, above on the following date ▶

Furthermore, this organization affirms that in the event it sells, exchanges, or otherwise disposes of the property described in Section B, Part I (or any portion thereof) within 3 years after the date of receipt, it will file **Form 8282,** Donee Information Return, with the IRS and give the donor a copy of that form. This acknowledgment does not represent agreement with the claimed fair market value.

Does the organization intend to use the property for an unrelated use? . . . . ▶ ☐ Yes ☐ No

Name of charitable organization (donee)	**Employer identification number**	
Address (number, street, and room or suite no.)	City or town, state, and ZIP code	
Authorized signature	Title	Date

Form **8835**

Department of the Treasury
Internal Revenue Service

Renewable Electricity, Refined Coal, and Indian Coal Production Credit

▶ Attach to your tax return.

▶ Information about Form 8835 and its separate instructions is at *www.irs.gov/form8835*.

OMB No. 1545-1362

2016

Attachment Sequence No. **95**

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Electricity and Refined Coal Produced at Qualified Facilities Placed in Service After October 22, 2004 (After October 2, 2008, for Electricity Produced From Marine and Hydrokinetic Renewables), and Indian Coal Produced at Facilities Placed in Service After August 8, 2005

			(a) Kilowatt-hours produced and sold (see instructions)	(b) Rate	(c) Column (a) x Column (b)
1	Electricity produced at qualified facilities using:				
a	Wind	1a		0.023	
b	Closed-loop biomass	1b		0.023	
c	Geothermal	1c		0.023	
d	Solar	1d		0.023	

e Add column (c) of lines 1a through 1d and enter here (see instructions) . . . **1e**

			(a) Kilowatt-hours produced and sold (see instructions)	(b) Rate	(c) Column (a) x Column (b)
2	Electricity produced at qualified facilities using:				
a	Open-loop biomass	2a		0.012	
b	Small irrigation power	2b		0.012	
c	Landfill gas	2c		0.012	
d	Trash	2d		0.012	
e	Hydropower	2e		0.012	
f	Marine and hydrokinetic renewables	2f		0.012	

Line	Description			Line	Amount
g	Add column (c) of lines 2a through 2f and enter here (see instructions)			2g	
3	Add lines 1e and 2g			3	
4	Phaseout adjustment (see instructions)	$	x	4	
5	Subtract line 4 from line 3			5	
	Refined coal produced at a qualified refined coal production facility				
6	Tons produced and sold (see instructions)	1212180	x $6.810	6	8,254,946.
7	Phaseout adjustment (see instructions)	$	x	7	
8	Subtract line 7 from line 6			8	8,254,946.
9	Reserved			9	
	Indian coal produced at a qualified Indian coal production facility				
10	Tons produced and sold (see instructions)		x $2.387	10	
11	Credit before reduction. Add lines 5, 8, and 10			11	8,254,946.
	Reduction for government grants, subsidized financing, and other credits:				
12	Total of government grants, proceeds of tax-exempt government obligations, subsidized energy financing, and any federal tax credits allowed for the project for this and all prior tax years (see instructions)			12	
13	Total of additions to the capital account for the project for this and all prior tax years			13	
14	Divide line 12 by line 13. Show as a decimal carried to at least 4 places			14	
15	Multiply line 11 by the smaller of 1/2 or line 14			15	
16	Subtract line 15 from line 11			16	8,254,946.
17a	Enter the amount from line 16 applicable to wind facilities the construction of which began during 2017			17a	
b	Multiply line 17a by 20% (0.20)			17b	
18	Subtract line 17b from line 16			18	8,254,946.
19	Renewable electricity, refined coal, and Indian coal production credit from partnerships, S corporations, cooperatives, estates, and trusts (see instructions)			19	
20	Add lines 18 and 19. Cooperatives, estates, and trusts, go to line 21. Partnerships and S corporations, stop here and report this amount on Schedule K. All others: For electricity or refined coal produced during the 4-year period beginning on the date the facility was placed in service or Indian coal produced, stop here and report the applicable part of this amount on Form 3800, Part III, line 4e. For all other production of electricity or refined coal, stop here and report the applicable part of this amount on Form 3800, Part III, line 1f (see instructions)			20	8,254,946.
21	Amount allocated to patrons of the cooperative or beneficiaries of the estate or trust (see instructions)			21	
22	Cooperatives, estates, and trusts, subtract line 21 from line 20. For electricity or refined coal produced during the 4-year period beginning on the date the facility was placed in service or Indian coal produced, report the applicable part of this amount on Form 3800, Part III, line 4e. For all other production of electricity or refined coal, report the applicable part of this amount on Form 3800, Part III, line 1f			22	

Form **8903** (Rev. December 2010) Department of the Treasury Internal Revenue Service

Domestic Production Activities Deduction

▶ Attach to your tax return. ▶ See separate instructions.

OMB No. 1545-1984
Attachment Sequence No. **143**

Name(s) as shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Note. Do not complete column (a), unless you have oil-related production activities. Enter amounts for all activities in column (b), including oil-related production activities.

Line	Description		(a) Oil-related production activities	(b) All activities
1	Domestic production gross receipts (DPGR)	1		4,497,365,433.
2	Allocable cost of goods sold. If you are using the small business simplified overall method, skip lines 2 and 3	2		4,338,581,720.
3	Enter deductions and losses allocable to DPGR (see instructions)	3		374,307,595.
4	If you are using the small business simplified overall method, enter the amount of cost of goods sold and other deductions or losses you ratably apportion to DPGR. All others, skip line 4	4		
5	Add lines 2 through 4	5		4,712,889,315.
6	Subtract line 5 from line 1	6		-215,523,882.
7	Qualified production activities income from estates, trusts, and certain partnerships and S corporations (see instructions)	7		
8	Add lines 6 and 7. Estates and trusts, go to line 9, all others, skip line 9 and go to line 10	8		
9	Amount allocated to beneficiaries of the estate or trust (see instructions)	9		
10a	**Oil-related qualified production activities income.** Estates and trusts, subtract line 9, column (a), from line 8, column (a), all others, enter amount from line 8, column (a). If zero or less, enter -0- here	10a		
b	**Qualified production activities income.** Estates and trusts, subtract line 9, column (b), from line 8, column (b), all others, enter amount from line 8, column (b). If zero or less, enter -0- here, skip lines 11 through 21, and enter -0- on line 22	10b		

Line	Description		
11	Income limitation (see instructions): • Individuals, estates, and trusts. Enter your adjusted gross income figured without the domestic production activities deduction • All others. Enter your taxable income figured without the domestic production activities deduction (tax-exempt organizations, see instructions)	11	
12	Enter the smaller of line 10b or line 11. If zero or less, enter -0- here, skip lines 13 through 21, and enter -0- on line 22	12	
13	Enter 9% of line 12	13	
14a	Enter the smaller of line 10a or line 12 — 14a		
b	Reduction for oil-related qualified production activities income. Multiply line 14a by 3%	14b	
15	Subtract line 14b from line 13	15	
16	Form W-2 wages (see instructions)	16	
17	Form W-2 wages from estates, trusts, and certain partnerships and S corporations (see instructions)	17	
18	Add lines 16 and 17. Estates and trusts, go to line 19, all others, skip line 19 and go to line 20	18	
19	Amount allocated to beneficiaries of the estate or trust (see instructions)	19	
20	Estates and trusts, subtract line 19 from line 18, all others, enter amount from line 18	20	
21	Form W-2 wage limitation. Enter 50% of line 20	21	
22	Enter the smaller of line 15 or line 21	22	
23	Domestic production activities deduction from cooperatives. Enter deduction from Form 1099-PATR, box 6	23	
24	Expanded affiliated group allocation (see instructions)	24	
25	**Domestic production activities deduction.** Combine lines 22 through 24 and enter the result here and on Form 1040, line 35; Form 1120, line 25; or the applicable line of your return	25	

Form **8911**

Department of the Treasury
Internal Revenue Service

Alternative Fuel Vehicle Refueling Property Credit

▶ Attach to your tax return.

▶ Information about Form 8911 and its instructions is at *www.irs.gov/form8911.*

OMB No. 1545-1981

2016

Attachment Sequence No. **151**

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part I Total Cost of Refueling Property

1	Total cost of qualified alternative fuel vehicle refueling property placed in service during the tax year (see **What's New** in the instructions)	1	9,755.

Part II Credit for Business/Investment Use Part of Refueling Property

2	Business/investment use part (see instructions)	2	9,755.
3	Section 179 expense deduction (see instructions)	3	
4	Subtract line 3 from line 2	4	9,755.
5	Multiply line 4 by 30% (0.30)	5	2,927.
6	Maximum business/investment use part of credit (see instructions)	6	2,927.
7	Enter the **smaller** of line 5 or line 6	7	2,927.
8	Alternative fuel vehicle refueling property credit from partnerships and S corporations (see instructions)	8	
9	**Business/investment use part of credit.** Add lines 7 and 8. Partnerships and S corporations, stop here and report this amount on Schedule K. All others, report this amount on Form 3800, Part III, line 1s	9	2,927.

Part III Credit for Personal Use Part of Refueling Property

10	Subtract line 2 from line 1. If zero, stop here; **do not** file this form unless you are claiming a credit on line 9	10	
11	Multiply line 10 by 30% (0.30)	11	
12	Maximum personal use part of credit (see instructions)	12	
13	Enter the **smaller** of line 11 or line 12	13	
14	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46; or the sum of the amounts from Form 1040NR, lines 42 and 44. • Other filers. Enter the regular tax before credits from your return.	14	
15	Credits that reduce regular tax before the alternative fuel vehicle refueling property credit:		
a	Foreign tax credit — 15a		
b	Certain allowable credits (see instructions) — 15b		
c	Add lines 15a and 15b	15c	
16	Net regular tax. Subtract line 15c from line 14. If zero or less, enter -0- and stop here; **do not** file this form unless you are claiming a credit on line 9	16	
17	Tentative minimum tax (see instructions): • Individuals. Enter the amount from Form 6251, line 33. • Other filers. Enter the tentative minimum tax from your alternative minimum tax form or schedule.	17	
18	Subtract line 17 from line 16. If zero or less, stop here; **do not** file this form unless you are claiming a credit on line 9	18	
19	**Personal use part of credit.** Enter the **smaller** of line 13 or line 18 here and on Form 1040, line 54; Form 1040NR, line 51; or the appropriate line of your return. If line 18 is smaller than line 13, see instructions	19	

For Paperwork Reduction Act Notice, see instructions.

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Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent
SCANA CORPORATION

Employer identification number
57-0784499

Name of subsidiary

Employer identification number

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs		361,986.		361,986.
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)	235,499,349.	Stmt 91 -72,802,725.		162,696,624.
7	Other items with no differences	1,933,500,729.	Stmt 92		1,933,500,729.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	2,169,000,078.	-72,440,739.		2,096,559,339.

For Paperwork Reduction Act Notice, see instructions.

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SCANA CORPORATION 57-0784499

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income		31,525.		
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	63,471.			63,471.
5	Other interest income Stmt 94	40,173,397.	200,970,065.		241,143,462.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	40,236,868.	201,001,590.		241,238,458.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,317,328.			1,317,328.
4	Other interest expense Stmt 97	340,952,042.	42,908,253.		383,860,295.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	342,269,370.	42,908,253.		385,177,623.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent	Employer identification number
SCANA CORPORATION	57-0784499
Name of subsidiary	Employer identification number
SCANA CORPORATION	57-0784499

Part I **Cost of Goods Sold**

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences				
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions				

For Paperwork Reduction Act Notice, see instructions.

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SCANA CORPORATION 57-0784499

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income		15,820.		
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	8,327,745.			8,327,745.
5	Other interest income	1,595,218.	-1,382,225.		212,993.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	9,922,963.	-1,366,405.		8,556,558.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group				
4	Other interest expense	54,743,724.	-3,597.		54,740,127.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	54,743,724.	-3,597.		54,740,127.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent	Employer identification number
SCANA CORPORATION	57-0784499
Name of subsidiary	**Employer identification number**
SCANA SERVICES INC	57-1092169

Part I **Cost of Goods Sold**

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences	74,318,188.			74,318,188.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	74,318,188.			74,318,188.

For Paperwork Reduction Act Notice, see instructions. Form **8916-A** (2016)

SCANA SERVICES INC 57-1092169

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	716,842.			716,842.
5	Other interest income	13,954.			13,954.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	730,796.			730,796.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	9,118,712.			9,118,712.
4	Other interest expense	462.			462.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	9,119,174.			9,119,174.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent
SCANA CORPORATION

Employer identification number
57-0784499

Name of subsidiary
SOUTH CAROLINA ELECTRIC and GAS COMPANY

Employer identification number
57-0248695

Part I **Cost of Goods Sold**

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs		222,266.		222,266.
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)		-16,857,064.		-16,857,064.
7	Other items with no differences	1,104,945,601.			1,104,945,601.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	1,104,945,601.	-16,634,798.		1,088,310,803.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	59,543.			59,543.
5	Other interest income	31,945,071.	203,397,097.		235,342,168.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	32,004,614.	203,397,097.		235,401,711.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	6,644,766.			6,644,766.
4	Other interest expense	248,048,905.	42,604,735.		290,653,640.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	254,693,671.	42,604,735.		297,298,406.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent	Employer identification number
SCANA CORPORATION	57-0784499
Name of subsidiary	Employer identification number
SOUTH CAROLINA FUEL CO INC	57-0691209

Part I **Cost of Goods Sold**

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs				
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)	235,135,917.	-55,780,868.		179,355,049.
7 Other items with no differences				
8 **Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	235,135,917.	-55,780,868.		179,355,049.

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SOUTH CAROLINA FUEL CO INC 57-0691209

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group				
5	Other interest income				
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.				

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	58,045.			58,045.
4	Other interest expense	1,787,247.			1,787,247.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	1,845,292.			1,845,292.

Form **8916-A** Department of the Treasury Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123
2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: SC GENERATING COMPANY INC
Employer identification number: 57-0784498

Part I **Cost of Goods Sold**

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences	113,725,200.			113,725,200.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	113,725,200.			113,725,200.

SC GENERATING COMPANY INC 57-0784498

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	29.			29.
5	Other interest income	54,017.	-31,785.		22,232.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	54,046.	-31,785.		22,261.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,212,200.			1,212,200.
4	Other interest expense	14,133,651.	-482,617.		13,651,034.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	15,345,851.	-482,617.		14,863,234.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent	Employer identification number
SCANA CORPORATION	57-0784499
Name of subsidiary	Employer identification number
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908

Part I **Cost of Goods Sold**

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs				
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)				
7 Other items with no differences				
8 **Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions				

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SCANA COMMUNICATIONS HOLDINGS INC 31-0394908

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group				
5	Other interest income	6,321.			6,321.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	6,321.			6,321.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group				
4	Other interest expense				
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.				

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent	Employer identification number
SCANA CORPORATION	57-0784499
Name of subsidiary	Employer identification number
SCANA ENERGY MARKETING INC	57-0850977

Part I **Cost of Goods Sold**

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs		77,007.		77,007.
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences	812,053,946.			812,053,946.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	812,053,946.	77,007.		812,130,953.

SCANA ENERGY MARKETING INC 57-0850977

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	373,958.			373,958.
5	Other interest income	221.			221.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	374,179.			374,179.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,083,289.			1,083,289.
4	Other interest expense	-12,434.			-12,434.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	1,070,855.			1,070,855.

Form **8916-A**
Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123
2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: SERVICECARE INC
Employer identification number: 57-1007394

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences				
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions				

SERVICECARE INC 57-1007394

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	5,863.			5,863.
5	Other interest income				
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	5,863.			5,863.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group				
4	Other interest expense				
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.				

Form **8916-A** Department of the Treasury Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORTATED
Employer identification number: 56-2128483

Part I Cost of Goods Sold

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs		62,713.		62,713.
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)	363,432.	-164,793.		198,639.
7 Other items with no differences	204,814,883.			204,814,883.
8 **Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	205,178,315.	-102,080.		205,076,235.

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PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	96.			96.
5	Other interest income	6,572,549.	-1,013,022.		5,559,527.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	6,572,645.	-1,013,022.		5,559,623.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,022,792.			1,022,792.
4	Other interest expense	24,154,282.	789,732.		24,944,014.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	25,177,074.	789,732.		25,966,806.

Form **8916-A**
Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
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OMB No. 1545-0123
2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: PSNC BLUE RIDGE CORPORATION
Employer identification number: 56-1791764

Part I **Cost of Goods Sold**

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences				
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions				

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PSNC BLUE RIDGE CORPORATION 56-1291764

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income		3,557.		
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group				
5	Other interest income				
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.		3,557.		3,557.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group				
4	Other interest expense				
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.				

Form **8916-A**
Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
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OMB No. 1545-0123
2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: PSNC CARDINAL PIPELINE COMPANY
Employer identification number: 56-1955423

Part I **Cost of Goods Sold**

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs				
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)				
7 Other items with no differences				
8 **Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions				

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PSNC CARDINAL PIPELINE COMPANY 56-1955423

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income		12,148.		
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group				
5	Other interest income				
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.		12,148.		12,148.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group				
4	Other interest expense				
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.				

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION

Employer identification number: 57-0784499

Name of subsidiary: ELIMINATIONS SCANA CORPORATIO

Employer identification number:

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences	-376,357,089.			-376,357,089.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	-376,357,089.			-376,357,089.

For Paperwork Reduction Act Notice, see instructions. Form **8916-A** (2016)

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ELIMINATIONS SCANA CORPORATIO

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	-9,420,605.			-9,420,605.
5	Other interest income	-13,954.			-13,954.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	-9,434,559.			-9,434,559.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	-17,822,476.			-17,822,476.
4	Other interest expense	-1,903,795.			-1,903,795.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	-19,726,271.			-19,726,271.

Form **8925**

(Rev. January 2010)

Department of the Treasury
Internal Revenue Service (99)

Report of Employer-Owned Life Insurance Contracts

▶ **Attach to the policyholder's tax return - See instructions.**

OMB No. 1545-2089

Attachment Sequence No. **160**

Name(s) as shown on return	Identifying number
SCANA CORPORATION	57-0784499
Name of policyholder, if different from above	Identifying number, if different from above

Type of business

HOLDING COMPANY UTILITY

1	Enter the number of employees the policyholder had at the end of the tax year	1	5,775.
2	Enter the number of employees included on line 1 who were insured at the end of the tax year under the policyholder's employer-owned life insurance contract(s) issued after August 17, 2006. See *Section 1035 exchanges* on page 2 for an exception	2	3.
3	Enter the total amount of employer-owned life insurance in force at the end of the tax year for employees who were insured under the contract(s) specified on line 2	3	1,160,000.
4a	Does the policyholder have a valid consent (see instructions) for each employee included on line 2? [X] **Yes** [ ] **No**		
b	If "No," enter the number of employees included on line 2 for whom the policyholder does not have a valid consent	4b	

General Instructions

Section references are to the Internal revenue Code unless otherwise noted.

Purpose of Form

Use Form 8925 to report the number of employees covered by employer-owned life insurance contracts issued after August 17, 2006, and the total amount of employer-owned life insurance in force on those employees at the end of the tax year. Policyholders must also indicate whether a valid consent has been received from each covered employee, and the number of covered employees for which a valid consent has not been received.

See sections 101(j) and 6039I, and Notice 2009-48, 2009-24 I.R.B. 1085, for more information.

Definitions

Employer-owned life insurance contract. For purposes of Form 8925, an insurance contract is an employer-owned life insurance contract if it is owned by a policyholder as defined below, and covers the life of the policyholder's employee(s) on the date the life insurance contract is issued. If you have master contracts, see section 101(j)(3) for additional information.

Policyholder. For purposes of Form 8925 and these instructions, a policyholder is an "applicable policyholder" as defined in section 101(j)(3)(B). Generally, a policyholder is the person who owns the employer-owned life insurance contract, and who is (a) engaged in a trade or business that employs the person insured under the employer-owned life insurance contract and (b) the direct or indirect beneficiary of the employer-owned life insurance contract.

Related person. A related person is considered a policyholder if that person is (a) related to the policyholder (defined earlier) under sections 267(b) or 707(b)(1), or (b) engaged in a trade or business under common control with the policyholder. See sections 52(a) and (b).

Employee. Employee includes an officer, director, or highly compensated employee under section 414(q).

Insured. An individual must be a U.S. citizen or resident to be considered insured under an employer-owned life insurance contract. Both individuals covered by a contract covering the joint lives of two individuals are considered insured.

Notice and consent requirements. To qualify as an employer-owned life insurance contract, the policyholder must meet the notice and consent requirements listed below before the issuance of the contract.

1. Provide written notification to the employee stating the policyholder intends to insure the employee's life and the maximum face amount for which the employee could be insured at the time the contract was issued.

The written notification must include a disclosure of the face amount of life insurance, either in dollars or as a multiple of salary, that the policyholder reasonably expects to purchase with regard to the employee during the course of the employee's tenure. Additional notice and consent are required if the aggregate face amount of the employer-owned life insurance contracts with regard to an employee exceeds the amount of which the employee was given notice and to which the employee consented. See Q&A-9 and Q&A-12 in Notice 2009-48.

2. Provide written notification to the employee that the policyholder will be a beneficiary of any proceeds payable upon the death of the employee.

3. Received written consent from the employee. See *Valid consent* under the instructions for line 4a.

Electronic notification and consent. The written notification and consent requirement can be met electronically only if the system for electronic notification and consent meets requirements 1 through 3, above. See Q&A-11 in Notice 2009-48 for more information.

Issue date of contract. Generally, the issue date of a life insurance contract is the date on the policy assigned by the insurance company on or after the date of application. For purposes of meeting the notice and consent requirements, the issue date of the employer-owned life insurance contract is the later of (1) the date of application of coverage, (2) the effective date of coverage, or (3) the formal issuance of the contract. See Q&A-4 in Notice 2009-48 for more information.

Regulation Section 1.263(a)-1(f) - De Minimis Safe Harbor Election

Taxpayer Name: SCANA CORPORATION

Taxpayer Address: 220 OPERATION WAY CAYCE SC 29033-3701

Taxpayer ID Number: 57-0784499

Year-End: 12/31/2016

Under IRC Regulation Section 1.263(a)-1(f), the taxpayer hereby elects to apply the de minimis safe harbor election.

Election To Deduct Start-Up Expenditures
IRC Section 195

Taxpayer Name: SCANA SERVICES INC
Taxpayer ID Number: 57-1092169
Year-end: 12/31/2016

Section 195 Election

In accordance with IRC Sec. 195, taxpayer hereby elects to deduct start-up expenditures up to $5,000 in the tax year in which the business begins. The remainder of the startup expenditures are deductible ratably over 180 months, beginning with 07/14/2005, the month that the corporation's active trade or business began (or was acquired).

The trade or business of the taxpayer to which this election relates is SCANA Pharmacy.

The start-up expense incurred are:

Description of Start-Up Expense	Date Incurred	Amount
SALARIES AND MISCELLANEOUS	06/01/2005	165,233.
	Total	165,233.

Consolidated Schedules
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		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1a	Gross receipts or sales	5,217,353,893.	-719,988,460.		4,497,365,433.
1b	Returns and allowances				
1c	Balance	5,217,353,893.	-719,988,460.		4,497,365,433.
2	Cost of goods sold	2,494,537,833.	-376,357,089.		2,118,180,744.
3	Gross profit	2,722,816,060.	-343,631,371.		2,379,184,689.
4	Dividends	337,492.			337,492.
5	Interest	250,673,017.	-9,434,559.		241,238,458.
6	Gross rents	22,485,964.	-6,676,572.		15,809,392.
7	Gross royalties				
8	Capital gain net income	232,440.		-1,646.	230,794.
9	Net gain or (loss) from Form 4797	-51,773,563.		1,646.	-51,771,917.
10	Other income	28,218,759.	-722,418.		27,496,341.
11	Total income	2,972,990,169.	-360,464,920.		2,612,525,249.
12	Compensation of officers	15,144,833.			15,144,833.
13	Salaries and wages	196,779,280.	-116,276,230.		80,503,050.
14	Repairs and maintenance	304,310,651.	-55,589,061.		248,721,590.
15	Bad debts	10,405,142.	-57,907.		10,347,235.
16	Rents	19,818,345.	-15,121,806.		4,696,539.
17	Taxes and licenses	273,148,980.	-16,528,705.		256,620,275.
18	Interest	404,903,894.	-19,726,271.		385,177,623.
19	Charitable contributions	3,585,739.	NONE	-3,585,739.	NONE
20	Depreciation	674,906,524.			674,906,524.
21	Depletion				
22	Advertising	13,299,533.	-814,120.		12,485,413.
23	Pension, profit-sharing etc., plans	1,059,828.	-364,871.		694,957.
24	Employee benefit programs	86,473,736.	-29,670,928.		56,802,808.
25	Domestic production activities deduction				
26	Other deductions	1,029,639,251.	-106,315,021.		923,324,230.
27	Total deductions	3,033,475,736.	-360,464,920.	-3,585,739.	2,669,425,077.
28	Taxable income before NOL & Spec. Deductions	-60,485,567.	NONE	3,585,739.	-56,899,828.
29	NOL,Spec. deductions	212,200.			212,200.
30	Taxable income	-60,697,767.	NONE	3,585,739.	-57,112,028.

Consolidated Schedules
1120 Page 1

		SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
		57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
1a	Gross receipts or sales		413,279,684.	2,998,699,530.	237,225,342.	193,888,768.		938,277,430.	
1b	Returns and allowances								
1c	Balance		413,279,684.	2,998,699,530.	237,225,342.	193,888,768.		938,277,430.	
2	Cost of goods sold		74,318,188.	1,088,310,803.	179,355,049.	113,725,200.		833,752,358.	
3	Gross profit		338,961,496.	1,910,388,727.	57,870,293.	80,163,568.		104,525,072.	
4	Dividends	337,492.							
5	Interest	8,556,558.	730,796.	235,401,711.		22,261.	6,321.	374,179.	5,863.
6	Gross rents		735,204.	20,964,105.		10,903.			
7	Gross royalties								
8	Capital gain net income	230,794.	NONE	NONE				1,646.	
9	Net gain or (loss) from Form 4797		-696,096.	-38,024,208.		-3,530,135.			
10	Other income	-33,798.	722,418.	10,233,647.		-585,541.	1,186,550.	10,217.	
11	Total income	9,091,046.	340,453,818.	2,138,963,982.	57,870,293.	76,081,056.	1,192,871.	104,911,114.	5,863.
12	Compensation of officers			15,144,833.					
13	Salaries and wages	371,386.	102,987,502.	55,188,382.	3,529.	1,541,100.	2,400.	16,135,231.	2,541.
14	Repairs and maintenance		51,734,339.	215,401,652.		18,725,651.		574,178.	356.
15	Bad debts		57,907.	6,349,958.				3,429,159.	-593.
16	Rents		9,357,222.	6,587,833.		78,729.	2,400.	1,974,447.	
17	Taxes and licenses	287,115.	16,538,705.	230,655,590.	2,978.	7,397,963.	1,230.	3,270,779.	359.
18	Interest	54,740,127.	9,119,174.	297,298,406.	1,845,292.	14,863,234.		1,070,855.	
19	Charitable contributions	145.	NONE	2,736,550.		12,417.		453,434.	
20	Depreciation		15,840,260.	431,921,192.	46,060,920.	19,590,347.		955,303.	
21	Depletion								
22	Advertising		814,120.	371,874.				11,082,729.	
23	Pension, profit-sharing etc., plans	-1,502,226.	364,871.	1,368,809.	11.	19,491.		53,040.	849,150.
24	Employee benefit programs	-2,896,149.	29,670,928.	43,614,763.	1,038.	1,568,904.		4,321,315.	313,850.
25	Domestic production activities deduction								
26	Other deductions	23,866,947.	93,283,085.	862,060,752.	236,577.	2,727,592.	14,601.	13,403,489.	32,380.
27	Total deductions	74,867,345.	329,768,113.	2,168,700,594.	48,150,345.	66,525,428.	20,631.	56,723,959.	1,198,043.
28	Taxable income before NOL & Spec. Deductions	-65,776,299.	10,685,705.	-29,736,612.	9,719,948.	9,555,628.	1,172,240.	48,187,155.	-1,192,180.
29	NOL,Spec. deductions	212,200.							
30	Taxable income	-65,988,499.	10,685,705.	-29,736,612.	9,719,948.	9,555,628.	1,172,240.	48,187,155.	-1,192,180.

Consolidated Schedules 1120 Page 1	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483	CLEAN ENERGY ENTERPRISES INC 56-1078443	PSNC BLUE RIDGE CORPORATION 56-1791764	PSNC CARDINAL PIPELINE COMPANY 56-1955423	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
1a Gross receipts or sales	435,983,139.				
1b Returns and allowances					
1c Balance	435,983,139.				
2 Cost of goods sold	205,076,235.				
3 Gross profit	230,906,904.				
4 Dividends					
5 Interest	5,559,623.		3,557.	12,148.	
6 Gross rents	775,752.				
7 Gross royalties					
8 Capital gain net income					
9 Net gain or (loss) from Form 4797	-9,523,124.				
10 Other income	11,979,514.		1,615,439.	3,090,313.	
11 Total income	239,698,669.		1,618,996.	3,102,461.	
12 Compensation of officers					
13 Salaries and wages	20,547,209.				
14 Repairs and maintenance	17,874,475.				
15 Bad debts	568,711.				
16 Rents	1,817,714.				
17 Taxes and licenses	14,849,692.	1,000.	51,371.	92,198.	
18 Interest	25,966,806.				
19 Charitable contributions	383,193.				
20 Depreciation	160,538,502.				
21 Depletion					
22 Advertising	1,030,810.				
23 Pension, profit-sharing etc., plans	-93,318.				
24 Employee benefit programs	9,879,087.				
25 Domestic production activities deduction					
26 Other deductions	34,013,125.	703.			
27 Total deductions	287,376,006.	1,703.	51,371.	92,198.	
28 Taxable income before NOL & Spec. Deductions	-47,677,337.	-1,703.	1,567,625.	3,010,263.	NONE
29 NOL,Spec. deductions					
30 Taxable income	-47,677,337.	-1,703.	1,567,625.	3,010,263.	NONE

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Line 10 - Other Income

SCANA CORPORATION

INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	-33,798.
Subtotal	-33,798.

SCANA SERVICES INC

GAIN ON LAND SALES	269,581.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	452,837.
Subtotal	722,418.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

GAIN ON LAND SALES	
INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	-4,833,278.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	15,066,925.
Subtotal	10,233,647.

SC GENERATING COMPANY INC

MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-585,541.
Subtotal	-585,541.

SCANA COMMUNICATIONS HOLDINGS INC

INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	1,186,550.
Subtotal	1,186,550.

SCANA ENERGY MARKETING INC

MISCELLANEOUS INCOME WITHOUT DIFFERENCES	10,217.
Subtotal	10,217.

Continued on next page

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Line 10 - Other Income (Cont'd)

PUBLIC SERVICE COMPANY OF NORTH CAROLINA	
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	11,979,514.
Subtotal	11,979,514.
PSNC BLUE RIDGE CORPORATION	
PARTNERSHIP INCOME	1,615,439.
Subtotal	1,615,439.
PSNC CARDINAL PIPELINE COMPANY	
PARTNERSHIP INCOME	3,090,313.
Subtotal	3,090,313.
ELIMINATIONS SCANA CORPORATIO	
GAIN ON LAND SALES	-269,581.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-452,837.
Subtotal	-722,418.
Total Line 10 - Other Income	27,496,341.

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Line 19 - Contributions deduction

1.	Taxable income (excluding contributions and domestic production activities deduction)	-56,899,828.
2.	Less: NOL carryover	
3.	Plus: Capital Loss carryback	
4.	Taxable income without regard to contributions, special deductions, domestic production activities deduction, NOL carrybacks, and capital loss carrybacks	-56,899,828.
5.	Contribution deduction limitation (Taxable income x 10%)	NONE
6.	Amount of deductible contributions	3,585,739.
7.	Contribution deduction (Lesser of line 5 or line 6)	NONE

Line 19 - 5 Year contribution carryover

Year ending	Amount Available	Amount Utilized	Converted to NOL Carryover	Carryover to Next Year
12/31/2016	3,585,739.	NONE		3,585,739.
Total	3,585,739.	NONE		3,585,739.

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Line 26 - Other Deductions

SCANA CORPORATION

INJURIES AND DAMAGES	44,555.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	-3,186,573.
OFFICE SUPPLIES AND EXPENSES	1,926.
OUTSIDE SERVICES	2,030.
SELLING EXPENSES	-154,162.
ESOP DIVIDENDS	27,159,171.
Subtotal	23,866,947.

SCANA SERVICES INC

Amortization	2,139,118.
INJURIES AND DAMAGES	4,590,943.
INSURANCE	139,629.
MERCHANDISING EXPENSES	1,301,752.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	21,072,152.
OFFICE SUPPLIES AND EXPENSES	35,981,453.
OUTSIDE SERVICES	27,195,321.
SELLING EXPENSES	-19,408.
RESEARCH AND DEVELOPMENT	882,125.
Subtotal	93,283,085.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

Amortization	8,116,771.
Travel, Meals and Entertainment	1,001,437.
POLLUTION CONTROL	10,705,348.
INJURIES AND DAMAGES	5,807,027.
INSURANCE	7,158,823.
MERCHANDISING EXPENSES	1,031,448.
MISCELLANEOUS DEDUCTIONS	39,340,430.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	51,659,518.
OFFICE SUPPLIES AND EXPENSES	20,537,993.
OUTSIDE SERVICES	16,406,895.
PIPELINE INTEGRITY	-17,084,713.
481A ADJUSTMENT	-4,228,547.
RESEARCH AND DEVELOPMENT	721,608,322.
Subtotal	862,060,752.

Continued on next page

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Line 26 - Other Deductions (Cont'd)

SOUTH CAROLINA FUEL CO INC

OFFICE SUPPLIES AND EXPENSES	65.
OUTSIDE SERVICES	236,512.
Subtotal	236,577.

SC GENERATING COMPANY INC

Amortization	101,793.
Travel, Meals and Entertainment	372.
INJURIES AND DAMAGES	198,511.
INSURANCE	654,403.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	713,109.
OFFICE SUPPLIES AND EXPENSES	538,492.
OUTSIDE SERVICES	520,912.
Subtotal	2,727,592.

SCANA COMMUNICATIONS HOLDINGS INC

MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	434.
OFFICE SUPPLIES AND EXPENSES	2,907.
OUTSIDE SERVICES	11,260.
Subtotal	14,601.

SCANA ENERGY MARKETING INC

Amortization	1,098,647.
Travel, Meals and Entertainment	192,020.
DIRECTORS ENDOWMENT	
INJURIES AND DAMAGES	80,987.
INSURANCE	264,821.
LIFE INSURANCE	
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	2,193,541.
OFFICE SUPPLIES AND EXPENSES	7,529,342.
OUTSIDE SERVICES	1,912,193.
PENALTIES AND FINES	
RESEARCH AND DEVELOPMENT	131,938.
Subtotal	13,403,489.

Continued on next page

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Line 26 - Other Deductions (Cont'd)

SERVICECARE INC

INJURIES AND DAMAGES	3,709.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	24,640.
OFFICE SUPPLIES AND EXPENSES	4,031.
Subtotal	32,380.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

Amortization	147,348.
Travel, Meals and Entertainment	137,245.
INJURIES AND DAMAGES	1,352,006.
INSURANCE	592,872.
MERCHANDISING EXPENSES	2,130,960.
MISCELLANEOUS DEDUCTIONS	1,803,559.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	17,596,053.
OFFICE SUPPLIES AND EXPENSES	7,790,943.
OUTSIDE SERVICES	2,462,139.
Subtotal	34,013,125.

CLEAN ENERGY ENTERPRISES INC

OFFICE SUPPLIES AND EXPENSES	703.
Subtotal	703.

ELIMINATIONS SCANA CORPORATIO

INJURIES AND DAMAGES	-5,113,014.
INSURANCE	-139,629.
MERCHANDISING EXPENSES	-1,478,536.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	-35,176,019.
OFFICE SUPPLIES AND EXPENSES	-37,231,910.
OUTSIDE SERVICES	-27,195,321.
SELLING EXPENSES	19,408.
Subtotal	-106,315,021.

Total Line 26 - Other Deductions	923,324,230.

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Non-SRLY NOL Carryover Schedule

SCANA CORPORATION

Year Ending	Original NOL	Amount Available	Amount Used in Current Year	Converted Contributions	Carryover to Next Year
12/31/1997					
12/31/1998					
12/31/1999					
12/31/2000					
12/31/2001					
12/31/2002					
12/31/2003					
12/31/2004					
12/31/2005					
12/31/2006					
12/31/2007					
12/31/2008					
12/31/2009					
12/31/2010					
12/31/2011					
12/31/2012					
12/31/2013					
12/31/2014					
12/31/2015					
12/31/2016	57,112,028.	57,112,028.			57,112,028.
Total	57,112,028.	57,112,028.			57,112,028.

Consolidated Schedules

Sch. C Summary

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
	Dividends				
1	Domestic Corps-subj. to 70% ded	303,143.			303,143.
2	Domestic Corps-subj.to 80% ded				
3	Debt-Financed stock - Dom & Fgn				
4	Pref Stk < 20% owned Pub Util				
5	Pref Stk >= 20% owned Pub Util				
6	<20% Fgn Corps & FSC's-70%				
7	>=20% Fgn Corps & FSC's-80%				
8	Wholly-owned fgn subs-100%				
10	Domestic corps-Small Bus Inv				
11	From affiliated group member				
12	From certain FSCs				
13	Foreign corps not incl. above	34,349.			34,349.
14	Controlled fgn groups under Subpart F				
15	Foreign Dividend Gross-up				
16	IC-DISC and former DISC Div not included above				
17	Other dividends				
19	TOTAL DIVIDENDS	337,492.			337,492.
	Special Deductions				
1	Domestic Corp-subj. to 70% ded	212,200.			212,200.
2	Domestic Corp-subj. to 80% ded				
3	Debt-Financed stock-Dom & Fgn				
4	Pref Stk < 20% owned Pub Util				
5	Pref Stk >= 20% owned Pub Util				
6	<20% Fgn Corps & FSC's-70%				
7	>=20% Fgn Corps & FSC's-80%				
8	Wholly-owned fgn subs-100%				
9	Total Lines 1-8	212,200.			212,200.
10	Domestic corps-Small Bus Inv				
11	From affiliated group member				
12	From certain FSCs				
18	Deduction for Div Paid on Pref Stock of Public Utilities				
20	TOTAL SPECIAL DEDUCTIONS	212,200.			212,200.

Consolidated Schedules

Sch. C Summary

		SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
		57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
	Dividends								
1	Domestic Corps-subj. to 70% ded	303,143.							
2	Domestic Corps-subj.to 80% ded								
3	Debt-Financed stock - Dom & Fgn								
4	Pref Stk < 20% owned Pub Util								
5	Pref Stk > = 20% owned Pub Util								
6	<20% Fgn Corps & FSC's-70%								
7	>= 20% Fgn Corps & FSC's-80%								
8	Wholly-owned fgn subs-100%								
10	Domestic corps-Small Bus Inv								
11	From affiliated group member								
12	From certain FSCs								
13	Foreign corps not incl. above	34,349.							
14	Controlled fgn groups under Subpart F								
15	Foreign Dividend Gross-up								
16	IC-DISC and former DISC Div not included above								
17	Other dividends								
19	TOTAL DIVIDENDS	337,492.							
	Special Deductions								
1	Domestic Corp-subj. to 70% ded	212,200.							
2	Domestic Corp-subj. to 80% ded								
3	Debt-Financed stock-Dom & Fgn								
4	Pref Stk < 20% owned Pub Util								
5	Pref Stk > = 20% owned Pub Util								
6	<20% Fgn Corps & FSC's-70%								
7	>= 20% Fgn Corps & FSC's-80%								
8	Wholly-owned fgn subs-100%								
9	Total Lines 1-8	212,200.							
10	Domestic corps-Small Bus Inv								
11	From affiliated group member								
12	From certain FSCs								
18	Deduction for Div Paid on Pref Stock of Public Utilities								
20	TOTAL SPECIAL DEDUCTIONS	212,200.							

Consolidated Schedules Sch. C Summary	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483	CLEAN ENERGY ENTERPRISES INC 56-1078443	PSNC BLUE RIDGE CORPORATION 56-1791764	PSNC CARDINAL PIPELINE COMPANY 56-1955423	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
Dividends					
1 Domestic Corps-subj. to 70% ded					
2 Domestic Corps-subj.to 80% ded					
3 Debt-Financed stock - Dom & Fgn					
4 Pref Stk < 20% owned Pub Util					
5 Pref Stk > = 20% owned Pub Util					
6 <20% Fgn Corps & FSC's-70%					
7 >= 20% Fgn Corps & FSC's-80%					
8 Wholly-owned fgn subs-100%					
10 Domestic corps-Small Bus Inv					
11 From affiliated group member					
12 From certain FSCs					
13 Foreign corps not incl. above					
14 Controlled fgn groups under Subpart F					
15 Foreign Dividend Gross-up					
16 IC-DISC and former DISC Div not included above					
17 Other dividends					
19 TOTAL DIVIDENDS					
Special Deductions					
1 Domestic Corp-subj. to 70% ded					
2 Domestic Corp-subj. to 80% ded					
3 Debt-Financed stock-Dom & Fgn					
4 Pref Stk < 20% owned Pub Util					
5 Pref Stk >= 20% owned Pub Util					
6 <20% Fgn Corps & FSC's-70%					
7 >= 20% Fgn Corps & FSC's-80%					
8 Wholly-owned fgn subs-100%					
9 Total Lines 1-8					
10 Domestic corps-Small Bus Inv					
11 From affiliated group member					
12 From certain FSCs					
18 Deduction for Div Paid on Pref Stock of Public Utilities					
20 TOTAL SPECIAL DEDUCTIONS					

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Schedule K, Line 5b

Name of Entity	EIN	Country of Incorporation	Max Percentage Owned in Profit, Loss, or Capital
SCANA CORPORATION			
CANADYS REFINED COAL LLC	27-1302931	US	40.000
APOG LLC	26-0468152	US	25.000
CARDINAL PIPELINE COMPANY LLC	76-0489410	US	33.200
MAGNOLIA HOLDING COMPANY LLC	73-1665109	US	22.601

Consolidated Schedules

Sch. L - Beginning

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
	Assets				
1	Cash	236,349,831.			236,349,831.
2 a	Trade Notes and A/R	682,391,843.			682,391,843.
b	Less allowance for Bad Debts	5,269,711.			5,269,711.
3	Inventories	311,778,910.			311,778,910.
4	US Government Obligations				
5	Tax-exempt Securities				
6	Other Current Assets	434,193,743.	-282,411,660.		151,782,083.
7	Loans to Stockholders				
8	Mtge and Real Estate Loans				
9	Other Investments	6,367,451,758.	-6,127,305,346.		240,146,412.
10 a	Buildings and Other Depreciable Assets	18,667,897,661.			18,667,897,661.
b	Less Accum. Depreciation	5,975,136,607.			5,975,136,607.
11 a	Depletable Assets				
b	Less Accum. Depletion				
12	Land (net of any Amortization)				
13 a	Intangible Assets				
b	Less Accum. Amortization				
14	Other Assets	2,787,917,474.	-308,438,712.		2,479,478,762.
15	Total Assets	23,507,574,902.	-6,718,155,718.		16,789,419,184.
	Liabilities and Stockholders' Equity				
16	Accounts Payable	576,643,248.			576,643,248.
17	Mtges, Notes, Bond Payable in less than 1 year	647,291,449.			647,291,449.
18	Other Current Liabilities	936,333,856.	-282,411,661.		653,922,195.
19	Loans from Stockholders				
20	Mtges, Notes, Bonds Payable in 1 year or more	5,904,834,401.			5,904,834,401.
21	Other Liabilities	4,004,549,720.	-442,218,711.		3,562,331,009.
22 a	Capital stock-Preferred	100,000.	-100,000.		
b	Capital stock-Common	3,014,006,622.	-596,411,122.		2,417,595,500.
23	Additional Paid-in Capital	2,907,719,067.	-2,922,001,429.		-14,282,362.
24	Retained earnings-Appropriated				
25	Retained earnings-Unappropriated	5,608,554,333.	-2,490,250,595.		3,118,303,738.
26	Adjustments to shareholders' equity	-80,665,285.	15,237,800.		-65,427,485.
27	Less cost of Treasury Stock	11,792,509.			11,792,509.
28	Total Liabilities and Stockholders' Equity	23,507,574,902.	-6,718,155,718.		16,789,419,184.

Consolidated Schedules

Sch. L - Beginning

		SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
		57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
	Assets								
1	Cash	75,472,099.	42,487,869.	110,056,888.	-16,249,285.	11,512,507.	3,091,977.	7,619,603.	1,155,256.
2 a	Trade Notes and A/R		2,183,365.	521,796,470.		343,264.		94,110,229.	
b	Less allowance for Bad Debts			2,964,230.				1,673,736.	
3	Inventories		287,791.	171,415,921.	38,266,358.	24,000,296.		25,425,070.	
4	US Government Obligations								
5	Tax-exempt Securities								
6	Other Current Assets	136,985,242.	97,066,455.	106,231,635.	4,610,220.	34,172,067.		50,185,730.	1,000,147.
7	Loans to Stockholders								
8	Mtge and Real Estate Loans								
9	Other Investments	6,168,405,052.		171,160,735.				2,618.	
10 a	Buildings and Other Depreciable Assets		307,577,019.	14,615,659,537.	995,863,172.	702,081,252.		26,452,408.	
b	Less Accum. Depreciation		100,412,477.	4,150,427,302.	786,794,669.	238,603,058.		22,440,948.	
11 a	Depletable Assets								
b	Less Accum. Depletion								
12	Land (net of any Amortization)								
13 a	Intangible Assets								
b	Less Accum. Amortization								
14	Other Assets	371,434,886.	19,937,330.	2,183,067,690.	836,823.	47,670,033.		20,746,682.	454,900.
15	Total Assets	6,752,297,279.	369,127,352.	13,725,997,344.	236,532,619.	581,176,361.	3,091,977.	200,427,656.	2,610,303.
	Liabilities and Stockholders' Equity								
16	Accounts Payable	112,256.	67,629,087.	392,595,365.	20,640,493.	14,756,884.	623.	57,712,087.	
17	Mtges, Notes, Bond Payable in less than 1 year	41,760,000.	465,154.	303,880,566.	220,125,000.	6,666,667.			
18	Other Current Liabilities	-20,892,898.	123,856,804.	714,065,721.	-6,929,100.	58,729,004.	769,098.	35,585,033.	-10,684.
19	Loans from Stockholders								
20	Mtges, Notes, Bonds Payable in 1 year or more	879,200,000.	1.	4,429,036,067.		246,598,333.			
21	Other Liabilities	409,986,459.	170,325,390.	2,863,381,719.		128,417,123.		26,014,334.	1,376,485.
22 a	Capital stock-Preferred			100,000.					
b	Capital stock-Common	2,417,575,500.	1,000.	576,405,122.	1,000.	20,000,000.	20,000.	1,000.	1,000.
23	Additional Paid-in Capital	-9,030,772.	6,849,916.	2,183,832,337.	2,695,226.	32,307,572.	903,316.	45,455,110.	10,025,666.
24	Retained earnings-Appropriated								
25	Retained earnings-Unappropriated	3,111,012,466.		2,265,470,450.		73,707,400.	1,398,940.	46,380,846.	-8,580,838.
26	Adjustments to shareholders' equity	-65,633,223.		-2,770,003.		-6,622.		-10,720,754.	-201,326.
27	Less cost of Treasury Stock	11,792,509.							
28	Total Liabilities and Stockholders' Equity	6,752,297,279.	369,127,352.	13,725,997,344.	236,532,619.	581,176,361.	3,091,977.	200,427,656.	2,610,303.

Consolidated Schedules
Sch. L - Beginning

		PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483	CLEAN ENERGY ENTERPRISES INC 56-1078443	PSNC BLUE RIDGE CORPORATION 56-1791764	PSNC CARDINAL PIPELINE COMPANY 56-1955423	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
	Assets					
1	Cash	1,182,034.	20,883.			
2 a	Trade Notes and A/R	63,958,515.				
b	Less allowance for Bad Debts	631,745.				
3	Inventories	52,383,474.				
4	US Government Obligations					
5	Tax-exempt Securities					
6	Other Current Assets	3,941,247.				1,000.
7	Loans to Stockholders					
8	Mtge and Real Estate Loans					
9	Other Investments	-1,676,627.		6,849,868.	22,710,112.	
10 a	Buildings and Other Depreciable Assets	2,020,264,273.				
b	Less Accum. Depreciation	676,458,153.				
11 a	Depletable Assets					
b	Less Accum. Depletion					
12	Land (net of any Amortization)					
13 a	Intangible Assets					
b	Less Accum. Amortization					
14	Other Assets	143,762,018.		2,768.	4,344.	
15	Total Assets	1,606,725,036.	20,883.	6,852,636.	22,714,456.	1,000.
	Liabilities and Stockholders' Equity					
16	Accounts Payable	23,196,453.				
17	Mtges, Notes, Bond Payable in less than 1 year	74,394,062.				
18	Other Current Liabilities	28,648,006.	-28.	772,600.	1,740,300.	
19	Loans from Stockholders					
20	Mtges, Notes, Bonds Payable in 1 year or more	350,000,000.				
21	Other Liabilities	391,892,411.	3,177.	3,555,802.	9,596,820.	
22 a	Capital stock-Preferred					
b	Capital stock-Common	-3,000.	2,000.	1,000.	1,000.	1,000.
23	Additional Paid-in Capital	633,359,516.	438.	473,954.	846,788.	
24	Retained earnings-Appropriated					
25	Retained earnings-Unappropriated	106,559,263.	15,296.	2,053,827.	10,536,683.	
26	Adjustments to shareholders' equity	-1,321,675.		-4,547.	-7,135.	
27	Less cost of Treasury Stock					
28	Total Liabilities and Stockholders' Equity	1,606,725,036.	20,883.	6,852,636.	22,714,456.	1,000.

Consolidated Schedules

Sch. L - Ending

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
	Assets				
1	Cash	253,063,243.	-45,182,686.		207,880,557.
2 a	Trade Notes and A/R	828,058,874.	-94,874,493.		733,184,381.
b	Less allowance for Bad Debts	5,853,608.			5,853,608.
3	Inventories	290,480,845.			290,480,845.
4	US Government Obligations				
5	Tax-exempt Securities				
6	Other Current Assets	386,111,560.	-105,742,210.		280,369,350.
7	Loans to Stockholders				
8	Mtge and Real Estate Loans				
9	Other Investments	6,720,550,898.	-6,521,839,642.		198,711,256.
10 a	Buildings and Other Depreciable Assets	20,053,878,140.	1,079,817.		20,054,957,957.
b	Less Accum. Depreciation	6,207,830,938.	-753,558,215.		5,454,272,723.
11 a	Depletable Assets				
b	Less Accum. Depletion				
12	Land (net of any Amortization)				
13 a	Intangible Assets				
b	Less Accum. Amortization				
14	Other Assets	3,237,377,104.	-835,956,050.		2,401,421,054.
15	Total Assets	25,555,836,118.	-6,848,957,049.		18,706,879,069.
	Liabilities and Stockholders' Equity				
16	Accounts Payable	388,632,329.	-577.		388,631,752.
17	Mtges, Notes, Bond Payable in less than 1 year	957,426,831.			957,426,831.
18	Other Current Liabilities	1,153,020,799.	-433,993,990.		719,026,809.
19	Loans from Stockholders				
20	Mtges, Notes, Bonds Payable in 1 year or more	6,493,747,509.	-20,819,448.		6,472,928,061.
21	Other Liabilities	4,495,697,234.	-51,862,966.		4,443,834,268.
22 a	Capital stock-Preferred	100,000.	-100,000.		
b	Capital stock-Common	3,014,005,622.	-596,410,122.		2,417,595,500.
23	Additional Paid-in Capital	2,991,800,509.	-3,006,082,871.		-14,282,362.
24	Retained earnings-Appropriated				
25	Retained earnings-Unappropriated	6,127,906,624.	-2,744,662,271.		3,383,244,353.
26	Adjustments to Shareholders' Equity	-54,025,806.	4,975,196.		-49,050,610.
27	Less cost of Treasury Stock	12,475,533.			12,475,533.
28	Total Liabilities and Stockholders' Equity	25,555,836,118.	-6,848,957,049.		18,706,879,069.

SCANA CORPORATION 57-0784499

Consolidated Schedules

Sch. L - Ending

		SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA COMMUNICATIONS HOLDINGS INC 51-0394908	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394
	Assets								
1	Cash	67,880,818.	51,056,258.	112,818,510.	-5,463,007.	10,748,110.	1,883,815.	5,526,693.	
2 a	Trade Notes and A/R	89,024,551.	2,096,127.	514,133,020.		55,149.		122,704,581.	
b	Less allowance for Bad Debts			3,239,931.				2,081,935.	
3	Inventories		349,994.	172,900,770.	27,381,245.	25,835,508.		24,739,139.	
4	US Government Obligations								
5	Tax-exempt Securities								
6	Other Current Assets	120,478,566.	75,843,476.	91,205,043.	749,859.	32,306,162.		61,452,576.	
7	Loans to Stockholders								
8	Mtge and Real Estate Loans								
9	Other Investments	6,512,206,010.		180,487,957.				3,119.	
10 a	Buildings and Other Depreciable Assets		315,790,274.	15,686,426,272.	1,114,511,261.	707,077,289.		27,985,070.	
b	Less Accum. Depreciation		113,944,461.	4,272,332,560.	843,261,889.	249,525,438.		23,472,017.	
11 a	Depletable Assets								
b	Less Accum. Depletion								
12	Land (net of any Amortization)								
13 a	Intangible Assets								
b	Less Accum. Amortization								
14	Other Assets	440,317,704.	28,308,920.	2,536,656,672.	4,007,795.	48,206,224.		13,458,430.	
15	Total Assets	7,229,907,649.	359,500,588.	15,019,055,753.	297,925,264.	574,703,004.	1,883,815.	230,315,656.	
	Liabilities and Stockholders' Equity								
16	Accounts Payable	110,781.	51,824,886.	198,630,173.	10,140,208.	10,808,069.	577.	77,159,475.	
17	Mtges, Notes, Bond Payable in less than 1 year	68,800,000.	478,061.	525,461,103.	284,221,000.	6,666,667.			
18	Other Current Liabilities	91,482,330.	134,166,166.	796,820,781.	867,830.	51,317,156.	-974.	35,303,081.	
19	Loans from Stockholders								
20	Mtges, Notes, Bonds Payable in 1 year or more	874,800,000.		4,929,015,843.		239,931,666.			
21	Other Liabilities	471,027,096.	166,180,559.	3,230,551,722.		134,456,396.		32,087,426.	
22 a	Capital stock-Preferred			100,000.					
b	Capital stock-Common	2,417,575,500.	1,000.	576,405,122.	1,000.	20,000,000.	20,000.	1,000.	
23	Additional Paid-in Capital	-14,923,664.	6,849,916.	2,283,832,337.	2,695,226.	32,307,572.	903,316.	45,455,110.	
24	Retained earnings-Appropriated								
25	Retained earnings-Unappropriated	3,382,283,456.		2,481,211,937.		79,222,288.	960,896.	41,094,100.	
26	Adjustments to Shareholders' Equity	-48,772,317.		-2,973,265.		-6,810.		-784,536.	
27	Less cost of Treasury Stock	12,475,533.							
28	Total Liabilities and Stockholders' Equity	7,229,907,649.	359,500,588.	15,019,055,753.	297,925,264.	574,703,004.	1,883,815.	230,315,656.	

Consolidated Schedules
Sch. L - Ending

		PUBLIC SERVICE COMPANY OF NORTH CAROLINA	CLEAN ENERGY ENTERPRISES INC	PSNC BLUE RIDGE CORPORATION	PSNC CARDINAL PIPELINE COMPANY	SCANA CORPORATE SECURITY SERVICES INC
		56-2128483	56-1078443	56-1791764	56-1955423	20-0989017
	Assets					
1	Cash	8,591,163.	20,883.			
2 a	Trade Notes and A/R	100,045,446.				
b	Less allowance for Bad Debts	531,742.				
3	Inventories	39,274,189.				
4	US Government Obligations					
5	Tax-exempt Securities					
6	Other Current Assets	4,074,878.				1,000.
7	Loans to Stockholders					
8	Mtge and Real Estate Loans					
9	Other Investments	6,875.		6,356,521.	21,490,416.	
10 a	Buildings and Other Depreciable Assets	2,202,087,974.				
b	Less Accum. Depreciation	705,294,573.				
11 a	Depletable Assets					
b	Less Accum. Depletion					
12	Land (net of any Amortization)					
13 a	Intangible Assets					
b	Less Accum. Amortization					
14	Other Assets	166,423,214.		-2,119.	264.	
15	Total Assets	1,814,677,424.	20,883.	6,354,402.	21,490,680.	1,000.
	Liabilities and Stockholders' Equity					
16	Accounts Payable	39,958,160.				
17	Mtges, Notes, Bond Payable in less than 1 year	71,800,000.				
18	Other Current Liabilities	40,565,474.	20,455.	737,800.	1,740,700.	
19	Loans from Stockholders					
20	Mtges, Notes, Bonds Payable in 1 year or more	450,000,000.				
21	Other Liabilities	448,304,284.	4,880.	3,606,417.	9,478,454.	
22 a	Capital stock-Preferred					
b	Capital stock-Common	-3,000.	2,000.	1,000.	1,000.	1,000.
23	Additional Paid-in Capital	633,359,516.	438.	473,954.	846,788.	
24	Retained earnings-Appropriated					
25	Retained earnings-Unappropriated	132,184,843.	-6,890.	1,531,712.	9,424,282.	
26	Adjustments to Shareholders' Equity	-1,491,853.		3,519.	-544.	
27	Less cost of Treasury Stock					
28	Total Liabilities and Stockholders' Equity	1,814,677,424.	20,883.	6,354,402.	21,490,680.	1,000.

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Line 6 - Other Current Assets

	Beginning	Ending
SCANA CORPORATION		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	136,320,822.	120,009,610.
INTEREST AND DIVIDENDS RECEIVABLE	175,271.	1,449.
PREPAYMENTS	489,149.	467,507.
Subtotal	136,985,242.	120,478,566.
SCANA SERVICES INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	87,390,001.	65,319,345.
PREPAYMENTS	9,676,454.	10,524,131.
Subtotal	97,066,455.	75,843,476.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	13,994,351.	4,731,796.
INTEREST AND DIVIDENDS RECEIVABLE		121,727.
OTHER CURRENT ASSETS	10,356,905.	
PREPAYMENTS	81,880,379.	86,351,520.
Subtotal	106,231,635.	91,205,043.
SOUTH CAROLINA FUEL CO INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	4,013,064.	72,277.
PREPAYMENTS	597,156.	677,582.
Subtotal	4,610,220.	749,859.
SC GENERATING COMPANY INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	33,277,567.	31,405,850.
PREPAYMENTS	894,500.	900,312.
Subtotal	34,172,067.	32,306,162.

Continued on next page

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	Beginning	Ending
Line 6 - Other Current Assets (Cont'd)		
SCANA ENERGY MARKETING INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	23,765,369.	54,155,067.
OTHER CURRENT ASSETS	24,306,527.	2,663,111.
PREPAYMENTS	2,113,834.	4,634,398.
Subtotal	50,185,730.	61,452,576.
SERVICECARE INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	1,000,147.	
Subtotal	1,000,147.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	1,683,501.	
OTHER CURRENT ASSETS	698,330.	2,633,110.
PREPAYMENTS	1,559,416.	1,441,768.
Subtotal	3,941,247.	4,074,878.
SCANA CORPORATE SECURITY SERVICES INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	1,000.	1,000.
Subtotal	1,000.	1,000.
ELIMINATIONS SCANA CORPORATIO		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	-282,411,660.	-259,717,380.
OTHER CURRENT ASSETS		153,975,170.
Subtotal	-282,411,660.	-105,742,210.
Total Line 6 - Other Current Assets	151,782,083.	280,369,350.

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	Beginning	Ending
Line 9 - Other Investments		
SCANA CORPORATION		
INVEST IN ASSOC COMPANIES	6,127,511,084.	6,469,026,775.
INVESTMENT IN PARTNERSHIPS	708.	
OTHER INVESTMENTS	40,004,701.	43,490,676.
INVESTMENT IN SUBSIDIARIES	888,559.	-311,441.
Subtotal	6,168,405,052.	6,512,206,010.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
INVEST IN ASSOC COMPANIES		2,856,381.
OTHER INVESTMENTS	171,160,735.	177,631,576.
Subtotal	171,160,735.	180,487,957.
SCANA ENERGY MARKETING INC		
INVESTMENTS IN STOCK	2,618.	3,119.
Subtotal	2,618.	3,119.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
INVEST IN ASSOC COMPANIES	-4,082,101.	
OTHER INVESTMENTS	2,405,474.	6,875.
Subtotal	-1,676,627.	6,875.
PSNC BLUE RIDGE CORPORATION		
INVESTMENT IN PARTNERSHIPS	6,849,868.	6,356,521.
Subtotal	6,849,868.	6,356,521.
PSNC CARDINAL PIPELINE COMPANY		
INVESTMENT IN PARTNERSHIPS	22,710,112.	21,490,416.
Subtotal	22,710,112.	21,490,416.

Continued on next page

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	Beginning	Ending
Line 9 - Other Investments (Cont'd)		
ELIMINATIONS SCANA CORPORATIO		
INVEST IN ASSOC COMPANIES	-6,127,305,346.	-6,469,305,068.
OTHER INVESTMENTS		-52,534,574.
Subtotal	-6,127,305,346.	-6,521,839,642.
Total Line 9 - Other Investments	240,146,412.	198,711,256.
Line 14 - Other Assets		
SCANA CORPORATION		
ACC DEFERRED INCOME TAXES	58,734,712.	75,817,124.
DUE FROM AFFIL DIRECTORS ENDOWMENT	3,754,099.	3,908,222.
DUE FROM AFFILIATES	304,013,275.	356,540,764.
MISC DEFERRED DEBITS	1,174,677.	932,212.
UNAMORTIZED DEBT EXPENSE	3,758,123.	3,119,382.
Subtotal	371,434,886.	440,317,704.
SCANA SERVICES INC		
ACC DEFERRED INCOME TAXES	13,669,800.	19,221,300.
CLEARING ACCOUNTS	48,485.	217,289.
MISC DEFERRED DEBITS	6,219,045.	8,870,331.
Subtotal	19,937,330.	28,308,920.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACC DEFERRED INCOME TAXES	277,332,298.	354,286,724.
CLEARING ACCOUNTS	4,232.	418,919.
DUE FROM AFFIL DIRECTORS ENDOWMENT	382,447.	379,524.
MISC DEFERRED DEBITS	82,102,622.	163,564,671.
PRELIM SURVEY AND INVEST CHGS	198,470.	322,402.
REGULATORY ASSET - FASB 109	1,775,528,967.	1,967,097,185.
UNAMORTIZED DEBT EXPENSE	31,259,888.	35,470,866.

Continued on next page

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	Beginning	Ending
Line 14 - Other Assets (Cont'd)		
UNAMORTIZED LOSS ON REACQ DEBT	16,258,766.	15,116,381.
Subtotal	2,183,067,690.	2,536,656,672.
SOUTH CAROLINA FUEL CO INC		
ACC DEFERRED INCOME TAXES	-1,307,100.	2,411,500.
MISC DEFERRED DEBITS	2,143,923.	1,596,295.
Subtotal	836,823.	4,007,795.
SC GENERATING COMPANY INC		
ACC DEFERRED INCOME TAXES	6,005,900.	6,312,000.
CLEARING ACCOUNTS		1.
MISC DEFERRED DEBITS	1,718,750.	3,106,389.
REGULATORY ASSET - FASB 109	39,429,748.	38,334,875.
UNAMORTIZED DEBT EXPENSE	515,635.	452,959.
Subtotal	47,670,033.	48,206,224.
SCANA ENERGY MARKETING INC		
ACC DEFERRED INCOME TAXES	14,748,800.	11,617,800.
CLEARING ACCOUNTS	-290.	20.
MISC DEFERRED DEBITS	5,998,172.	1,840,610.
Subtotal	20,746,682.	13,458,430.
SERVICECARE INC		
ACC DEFERRED INCOME TAXES	454,900.	
Subtotal	454,900.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACC DEFERRED INCOME TAXES	28,922,800.	31,970,300.
CLEARING ACCOUNTS	-1.	
DUE FROM AFFIL DIRECTORS ENDOWMENT	59,371.	58,950.
MISC DEFERRED DEBITS	1,480,223.	539,079.

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	Beginning	Ending
Line 14 - Other Assets (Cont'd)		
REGULATORY ASSET - FASB 109	112,676,197.	132,879,041.
UNAMORTIZED DEBT EXPENSE	623,428.	975,844.
Subtotal	143,762,018.	166,423,214.
PSNC BLUE RIDGE CORPORATION		
ACC DEFERRED INCOME TAXES	2,768.	-2,119.
Subtotal	2,768.	-2,119.
PSNC CARDINAL PIPELINE COMPANY		
ACC DEFERRED INCOME TAXES	4,344.	264.
Subtotal	4,344.	264.
ELIMINATIONS SCANA CORPORATIO		
DUE FROM AFFIL DIRECTORS ENDOWMENT	-4,195,917.	-4,346,696.
DUE FROM AFFILIATES	-304,011,966.	-356,539,453.
MISC DEFERRED DEBITS	-230,829.	-475,069,901.
Subtotal	-308,438,712.	-835,956,050.
Total Line 14 - Other Assets	2,479,478,762.	2,401,421,054.

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	Beginning	Ending
Line 18 - Other Current Liabilities		
SCANA CORPORATION		
ACCRUED INTEREST PAYABLE	10,408,385.	10,391,508.
ACCRUED TAXES PAY - FEDERAL INCOME	-92,586,368.	-9,316,753.
ACCRUED TAXES PAY - STATE INCOME	-23,670,685.	1,946,908.
ACCTS PAYABLE - ASSOC COS	1,000.	1,000.
DIVIDENDS DECLARED	77,889,720.	82,177,227.
MISC CURRENT AND ACCRUED LIABILITIE	7,064,895.	6,282,440.
TAXES PAYABLE - SALES AND USE	155.	
Subtotal	-20,892,898.	91,482,330.
SCANA SERVICES INC		
ACCRUED INTEREST PAYABLE	1,997,877.	1,901,664.
ACCRUED TAXES PAY - FEDERAL INCOME	5,305,200.	3,657,500.
ACCRUED TAXES PAY - STATE INCOME	541,000.	848,600.
ACCRUED TAXES PAYABLE - OTHER	3,225,485.	3,786,070.
ACCTS PAYABLE - ASSOC COS	75,857,946.	74,347,946.
MISC CURRENT AND ACCRUED LIABILITIE	35,904,727.	48,633,766.
TAXES PAYABLE - OTHER	935,516.	936,716.
TAXES PAYABLE - SALES AND USE	89,053.	53,904.
Subtotal	123,856,804.	134,166,166.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACCRUED INTEREST PAYABLE	64,981,071.	66,073,421.
ACCRUED TAXES PAY - FEDERAL INCOME	139,536,235.	176,366,709.
ACCRUED TAXES PAY - STATE INCOME	31,166,055.	76,470,800.
ACCRUED TAXES PAYABLE - OTHER	173,595,618.	190,023,235.
ACCTS PAYABLE - ASSOC COS	71,894,901.	61,294,130.
CUSTOMER DEPOSITS	57,087,060.	60,283,425.
DIVIDENDS DECLARED	72,300,000.	77,500,000.
MISC CURRENT AND ACCRUED LIABILITIE	94,969,814.	80,313,106.
TAXES PAYABLE - OTHER	1,882,026.	1,970,592.
TAXES PAYABLE - SALES AND USE	6,652,941.	6,525,363.
Subtotal	714,065,721.	796,820,781.

Continued on next page

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Line 18 - Other Current Liabilities (Cont'd)

	Beginning	Ending
SOUTH CAROLINA FUEL CO INC		
ACCRUED INTEREST PAYABLE		2,431.
ACCRUED TAXES PAY - FEDERAL INCOME	-6,023,400.	538,099.
ACCRUED TAXES PAY - STATE INCOME	-905,700.	327,300.
Subtotal	-6,929,100.	867,830.
SC GENERATING COMPANY INC		
ACCRUED INTEREST PAYABLE	1,480,680.	1,414,749.
ACCRUED TAXES PAY - FEDERAL INCOME	860,180.	-850,210.
ACCRUED TAXES PAY - STATE INCOME	65,800.	161,000.
ACCRUED TAXES PAYABLE - OTHER	4,176,081.	4,985,039.
ACCTS PAYABLE - ASSOC COS	48,717,513.	43,021,488.
DIVIDENDS DECLARED	2,235,000.	1,560,000.
MISC CURRENT AND ACCRUED LIABILITIE	1,189,649.	1,026,395.
TAXES PAYABLE - SALES AND USE	4,101.	-1,305.
Subtotal	58,729,004.	51,317,156.
SCANA COMMUNICATIONS HOLDINGS INC		
ACCRUED TAXES PAY - FEDERAL INCOME	769,098.	-974.
Subtotal	769,098.	-974.
SCANA ENERGY MARKETING INC		
ACCRUED INTEREST PAYABLE	11,712.	33,415.
ACCRUED TAXES PAY - FEDERAL INCOME	-3,892,700.	4,634,200.
ACCRUED TAXES PAY - STATE INCOME	-2,475,357.	-1,128,633.
ACCRUED TAXES PAYABLE - OTHER	94,486.	83,856.
ACCTS PAYABLE - ASSOC COS	4,482,040.	439,780.
CUSTOMER DEPOSITS	10,857,077.	10,531,966.
DIVIDENDS DECLARED	3,250,000.	3,550,000.
MISC CURRENT AND ACCRUED LIABILITIE	20,389,595.	13,972,016.
TAXES PAYABLE - OTHER	49,753.	142,988.
TAXES PAYABLE - SALES AND USE	2,818,427.	3,043,493.
Subtotal	35,585,033.	35,303,081.

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	Beginning	Ending
Line 18 - Other Current Liabilities (Cont'd)		
SERVICECARE INC		
ACCRUED TAXES PAY - FEDERAL INCOME	-9,200.	
ACCRUED TAXES PAY - STATE INCOME	-1,600.	
ACCTS PAYABLE - ASSOC COS	116.	
Subtotal	-10,684.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACCRUED INTEREST PAYABLE	6,203,120.	6,395,626.
ACCRUED TAXES PAY - FEDERAL INCOME	-15,101,798.	-235,147.
ACCRUED TAXES PAY - STATE INCOME	-113,005.	-1,543,756.
ACCRUED TAXES PAYABLE - OTHER	278,766.	2,463,321.
ACCTS PAYABLE - ASSOC COS	5,804,421.	5,629,799.
CUSTOMER DEPOSITS	8,282,424.	7,553,872.
DIVIDENDS DECLARED	7,400,000.	5,188,117.
MISC CURRENT AND ACCRUED LIABILITIE	15,409,894.	14,674,459.
TAXES PAYABLE - OTHER	412,839.	398,186.
TAXES PAYABLE - SALES AND USE	71,345.	40,997.
Subtotal	28,648,006.	40,565,474.
CLEAN ENERGY ENTERPRISES INC		
ACCRUED TAXES PAY - FEDERAL INCOME		-400.
ACCRUED TAXES PAY - STATE INCOME	-18.	-18.
ACCRUED TAXES PAYABLE - OTHER	-10.	-10.
DIVIDENDS DECLARED		20,883.
Subtotal	-28.	20,455.
PSNC BLUE RIDGE CORPORATION		
ACCRUED TAXES PAY - FEDERAL INCOME	353,500.	382,600.
ACCRUED TAXES PAY - STATE INCOME	5,100.	-55,800.
DIVIDENDS DECLARED	414,000.	411,000.
Subtotal	772,600.	737,800.

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	Beginning	Ending
Line 18 - Other Current Liabilities (Cont'd)		
PSNC CARDINAL PIPELINE COMPANY		
ACCRUED TAXES PAY - FEDERAL INCOME	821,300.	878,000.
ACCRUED TAXES PAY - STATE INCOME	-10,000.	-67,300.
DIVIDENDS DECLARED	929,000.	930,000.
Subtotal	1,740,300.	1,740,700.
ELIMINATIONS SCANA CORPORATIO		
ACCRUED INTEREST PAYABLE	-1,997,877.	-1,901,664.
ACCTS PAYABLE - ASSOC COS	-195,228,784.	-168,655,716.
DIVIDENDS DECLARED	-85,185,000.	-89,160,000.
MISC CURRENT AND ACCRUED LIABILITIE		-174,276,610.
Subtotal	-282,411,661.	-433,993,990.
Total Line 18 - Other Current Liabilities	653,922,195.	719,026,809.
Line 21 - Other Liabilities		
SCANA CORPORATION		
ACC DEF FED INCOME TAX	-2,558,900.	-2,195,600.
ACC DEF STATE INCOME TAX	-384,700.	-330,100.
DEFERRED CREDITS - OTHER	76,554,360.	77,243,718.
DUE TO AFFILIATES	441,818.	438,474.
INJURIES AND DAMAGES RESERVE	10,702,473.	12,215,735.
POST RETIREMENT BENEFITS	327,334,566.	385,414,130.
UNAMORT DISCT - LT DEBT	-2,103,158.	-1,759,261.
Subtotal	409,986,459.	471,027,096.
SCANA SERVICES INC		
ACC DEF FED INCOME TAX	16,467,400.	16,229,000.
ACC DEF STATE INCOME TAX	2,112,000.	1,989,200.
DEFERRED CREDITS - OTHER	17,232,482.	20,159,841.
DUE TO AFFILIATES	133,780,000.	127,025,000.
INJURIES AND DAMAGES RESERVE	255,447.	777,518.

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	Beginning	Ending
Line 21 - Other Liabilities (Cont'd)		
OBLIGATIONS UNDER CAP LEASE	478,061.	
Subtotal	170,325,390.	166,180,559.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACC DEF FED INCOME TAX	1,692,572,092.	1,883,853,155.
ACC DEF STATE INCOME TAX	217,942,117.	241,044,075.
ACCUM DEF INVEST TAX CREDITS	23,580,500.	22,188,300.
DEFERRED CREDITS - OTHER	73,571,854.	49,074,144.
DUE TO AFFILIATES	212,184,657.	257,285,183.
FASB 109 REGULATORY LIABILITY	147,243,710.	238,854,458.
INJURIES AND DAMAGES RESERVE	5,355,089.	7,859,531.
OBLIGATIONS UNDER CAP LEASE	12,477,819.	20,678,011.
OTHER ASSET RETIREMENT OBLIGATIONS	476,223,696.	509,434,012.
UNAMORT DISCT - LT DEBT	2,230,185.	280,853.
Subtotal	2,863,381,719.	3,230,551,722.
SC GENERATING COMPANY INC		
ACC DEF FED INCOME TAX	89,978,500.	95,303,300.
ACC DEF STATE INCOME TAX	13,772,400.	14,517,600.
ACCUM DEF INVEST TAX CREDITS	1,970,709.	1,740,369.
DEFERRED CREDITS - OTHER	8,952,513.	8,099,452.
DUE TO AFFILIATES	653,122.	904,166.
FASB 109 REGULATORY LIABILITY	1,220,600.	1,078,000.
INJURIES AND DAMAGES RESERVE	132,848.	111,940.
OTHER ASSET RETIREMENT OBLIGATIONS	11,736,431.	12,701,569.
Subtotal	128,417,123.	134,456,396.
SCANA ENERGY MARKETING INC		
ACC DEF FED INCOME TAX	-536,400.	2,474,800.
ACC DEF STATE INCOME TAX	-91,500.	335,900.
DEFERRED CREDITS - OTHER	6,529,856.	6,876,324.
DUE TO AFFILIATES	20,112,378.	22,400,402.
Subtotal	26,014,334.	32,087,426.
SERVICECARE INC		
ACC DEF FED INCOME TAX	-106,200.	
ACC DEF STATE INCOME TAX	-16,000.	
DUE TO AFFILIATES	1,498,685.	

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	Beginning	Ending
Line 21 - Other Liabilities (Cont'd)		
Subtotal	1,376,485.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACC DEF FED INCOME TAX	238,639,500.	289,277,900.
ACC DEF STATE INCOME TAX	23,353,200.	20,235,600.
DEFERRED CREDITS - OTHER	5,067,901.	1,962,039.
DUE TO AFFILIATES	75,231,553.	81,203,455.
FASB 109 REGULATORY LIABILITY	17,073,625.	19,326,961.
INJURIES AND DAMAGES RESERVE	693,800.	691,270.
OTHER ASSET RETIREMENT OBLIGATIONS	31,832,832.	35,607,059.
Subtotal	391,892,411.	448,304,284.
CLEAN ENERGY ENTERPRISES INC		
DUE TO AFFILIATES	3,177.	4,880.
Subtotal	3,177.	4,880.
PSNC BLUE RIDGE CORPORATION		
ACC DEF FED INCOME TAX	3,750,000.	3,653,800.
ACC DEF STATE INCOME TAX	414,200.	296,800.
DUE TO AFFILIATES	-608,398.	-344,183.
Subtotal	3,555,802.	3,606,417.
PSNC CARDINAL PIPELINE COMPANY		
ACC DEF FED INCOME TAX	9,664,900.	9,471,600.
ACC DEF STATE INCOME TAX	1,010,200.	767,300.
DUE TO AFFILIATES	-1,078,280.	-760,446.
Subtotal	9,596,820.	9,478,454.
ELIMINATIONS SCANA CORPORATIO		
DEFERRED CREDITS - OTHER		436,293,964.
DUE TO AFFILIATES	-442,218,711.	-488,156,930.
Subtotal	-442,218,711.	-51,862,966.
Total Line 21 - Other Liabilities	3,562,331,009.	4,443,834,268.

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Consolidated Schedules				
Sch. M1 and M-2 Summary				
Schedule M-1				
1 Net income per books				
2 Federal Income Tax				
3 Excess Capital Losses				
4 Income Subject to Tax not on Books				
5 Expenses Recorded on Books not Deducted on Return				
a Depreciation				
b Charitable Contributions				
c Travel and Entertainment				
Other				
6 Total Lines 1-5				
7 Income Recorded on Books not Included on Return				
a Tax-exempt Interest				
Other				
8 Deductions on Return not on Books				
a Depreciation				
b Charitable Contributions				
Other				
9 Total Lines 7 and 8				
10 Income (Line 28, Page 1)				
Schedule M-2				
1 Balance at beginning of year	5,608,554,333.	-2,490,250,595.		3,118,303,738.
2 Net Income per Books	1,207,246,825.	-612,397,274.		594,849,551.
3 Other Increases	14,489,404.	-14,489,402.		2.
4 Total Line 1-3	6,830,290,562.	-3,117,137,271.		3,713,153,291.
5 Distributions				
a Cash	702,383,943.	-372,475,000.		329,908,943.
b Stock				
c Property				
6 Other Decreases	-5.			-5.
7 Total lines 5 and 6	702,383,938.	-372,475,000.		329,908,938.
8 Balance at end of year	6,127,906,624.	-2,744,662,271.		3,383,244,353.

SCANA CORPORATION 57-0784499

Consolidated Schedules
Sch. M1 and M-2 Summary

		SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
		57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
	Schedule M-1								
1	Net income per books								
2	Federal Income Tax								
3	Excess Capital Losses								
4	Income Subject to Tax not on Books								
5	Expenses Recorded on Books not Deducted on Return								
	a Depreciation								
	b Charitable Contributions								
	c Travel and Entertainment								
	Other								
6	Total Lines 1-5								
7	Income Recorded on Books not Included on Return								
	a Tax-exempt Interest								
	Other								
8	Deductions on Return not on Books								
	a Depreciation								
	b Charitable Contributions								
	Other								
9	Total Lines 7 and 8								
10	Income (Line 28, Page 1)								
	Schedule M-2								
1	Balance at beginning of year	3,111,012,466.		2,265,470,450.		73,707,400.	1,398,940.	46,380,846.	-8,580,838.
2	Net Income per Books	594,087,041.		512,691,484.		13,089,888.	761,956.	29,813,254.	-15,671.
3	Other Increases	5,892,892.		3.					8,596,509.
4	Total Line 1-3	3,710,992,399.		2,778,161,937.		86,797,288.	2,160,896.	76,194,100.	
5	Distributions								
	a Cash	328,708,943.		296,950,000.		7,575,000.	1,200,000.	35,100,000.	
	b Stock								
	c Property								
6	Other Decreases								
7	Total lines 5 and 6	328,708,943.		296,950,000.		7,575,000.	1,200,000.	35,100,000.	
8	Balance at end of year	3,382,283,456.	NONE	2,481,211,937.	NONE	79,222,288.	960,896.	41,094,100.	

Consolidated Schedules Sch. M1 and M-2 Summary	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483	CLEAN ENERGY ENTERPRISES INC 56-1078443	PSNC BLUE RIDGE CORPORATION 56-1791764	PSNC CARDINAL PIPELINE COMPANY 56-1955423	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
Schedule M-1					
1 Net income per books					
2 Federal Income Tax					
3 Excess Capital Losses					
4 Income Subject to Tax not on Books					
5 Expenses Recorded on Books not Deducted on Return					
a Depreciation					
b Charitable Contributions					
c Travel and Entertainment					
Other					
6 Total Lines 1-5					
7 Income Recorded on Books not Included on Return					
a Tax-exempt Interest					
Other					
8 Deductions on Return not on Books					
a Depreciation					
b Charitable Contributions					
Other					
9 Total Lines 7 and 8					
10 Income (Line 28, Page 1)					
Schedule M-2					
1 Balance at beginning of year	106,559,263.	15,296.	2,053,827.	10,536,683.	
2 Net Income per Books	54,283,691.	-1,303.	765,885.	1,770,600.	
3 Other Increases					
4 Total Line 1-3	160,842,954.	13,993.	2,819,712.	12,307,283.	
5 Distributions					
a Cash	28,658,117.	20,883.	1,288,000.	2,883,000.	
b Stock					
c Property					
6 Other Decreases	-6.			1.	
7 Total lines 5 and 6	28,658,111.	20,883.	1,288,000.	2,883,001.	
8 Balance at end of year	132,184,843.	-6,890.	1,531,712.	9,424,282.	

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Sch. M-2, Line 3 - Other Increases

SCANA CORPORATION	
Dissolution of Westex	5,892,892.
Subtotal	5,892,892.
SOUTH CAROLINA ELECTRIC and GAS COMPANY	
Other Increases	3.
Subtotal	3.
SERVICECARE INC	
Dissolution of ServiceCare	8,596,509.
Subtotal	8,596,509.
ELIMINATIONS SCANA CORPORATIO	
Rounding	-1.
Dissolution of ServiceCare	-8,596,509.
Dissolution of Westex	-5,892,892.
Subtotal	-14,489,402.
Total Sch. M-2, Line 3 - Other Increases	2.

Sch. M-2, Line 6 - Other Decreases

PUBLIC SERVICE COMPANY OF NORTH CAROLINA	
Other Decreases	-6.
Subtotal	-6.

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Sch. M-2, Line 6 - Other Decreases (Cont'd)

PSNC CARDINAL PIPELINE COMPANY

Other decreases	1.
Subtotal	1.
Total Sch. M-2, Line 6 - Other Decreases	-5.

Consolidated Schedules 4626-AMT	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1 Taxable income before NOL	-60,697,767.	NONE	3,585,739.	-57,112,028.
Adjustments and Preferences				
2 a Depr. of post 1986 property	-22,424,670.			-22,424,670.
b Amort of pollution control facilities				
c Amort of exploration and dev cost				
d Amort of circulation expenses				
e Adjusted gain or loss	1,703,217.			1,703,217.
f Long-term contracts				
g Merchant marine funds				
h Section 833(b) deduction				
i Tax shelter farm activities				
j Passive activities				
k Loss limitations				
l Depletion				
m Tax exempt interest				
n Intangible drilling costs				
o Other adjustments	NONE	NONE	NONE	NONE
3 Pre-adjustment AMTI	-81,419,220.	NONE	3,585,739.	-77,833,481.
Adjusted current earnings adj				
4 a ACE from line 10 of worksheet	-48,864,138.	NONE	3,585,739.	-45,278,399.
b Line 4a less line 3	32,555,082.	NONE		32,555,082.
c Line 4b multiplied by 75%	24,526,317.	NONE	-110,005.	24,416,312.
d Total increases over reductions				
e ACE adjustment	24,471,314.	NONE	-55,002.	24,416,312.
5 Sum of lines 3 and 4e	-56,947,906.	NONE	3,530,737.	-53,417,169.
6 AMT NOL deduction				
7 Alternative minimum taxable inc.	-56,947,906.	NONE	3,530,737.	-53,417,169.

SCANA CORPORATION

Consolidated Schedules 4626-AMT	SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA COMMUNICATIONS HOLDINGS INC 51-0394908	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394
1 Taxable income before NOL	-65,988,499.	10,685,705.	-29,736,612.	9,719,948.	9,555,628.	1,172,240.	48,187,155.	-1,192,180.
Adjustments and Preferences								
2 a Depr. of post 1986 property			-20,538,989.		-1,370,482.			
b Amort of pollution control facilities								
c Amort of exploration and dev cost								
d Amort of circulation expenses								
e Adjusted gain or loss		NONE	1,703,181.		36.			
f Long-term contracts								
g Merchant marine funds								
h Section 833(b) deduction								
i Tax shelter farm activities								
j Passive activities								
k Loss limitations								
l Depletion								
m Tax exempt interest								
n Intangible drilling costs								
o Other adjustments	NONE	NONE	NONE		NONE		NONE	
3 Pre-adjustment AMTI	-65,988,499.	10,685,705.	-48,572,420.	9,719,948.	8,185,182.	1,172,240.	48,187,155.	-1,192,180.
Adjusted current earnings adj								
4 a ACE from line 10 of worksheet	-38,617,128.	10,685,705.	-43,315,372.	9,719,948.	8,111,845.	1,172,240.	48,187,155.	-1,192,180.
b Line 4a less line 3	27,371,371.		5,257,048.		-73,337.			
c Line 4b multiplied by 75%	20,528,528.		3,942,786.		55,003.			
d Total increases over reductions								
e ACE adjustment	20,528,528.		3,942,786.					
5 Sum of lines 3 and 4e	-45,459,971.	10,685,705.	-44,629,634.	9,719,948.	8,185,182.	1,172,240.	48,187,155.	-1,192,180.
6 AMT NOL deduction								
7 Alternative minimum taxable inc.	-45,459,971.	10,685,705.	-44,629,634.	9,719,948.	8,185,182.	1,172,240.	48,187,155.	-1,192,180.

	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	CLEAN ENERGY ENTERPRISES INC	PSNC BLUE RIDGE CORPORATION	PSNC CARDINAL PIPELINE COMPANY	SCANA CORPORATE SECURITY SERVICES INC
Consolidated Schedules	56-2128483	56-1078443	56-1791764	56-1955423	20-0989017
4626-AMT					
1 Taxable income before NOL	-47,677,337.	-1,703.	1,567,625.	3,010,263.	NONE
Adjustments and Preferences					
2 a Depr. of post 1986 property	-179,100.		-418.	-335,681.	
b Amort of pollution control facilities					
c Amort of exploration and dev cost					
d Amort of circulation expenses					
e Adjusted gain or loss					
f Long-term contracts					
g Merchant marine funds					
h Section 833(b) deduction					
i Tax shelter farm activities					
j Passive activities					
k Loss limitations					
l Depletion					
m Tax exempt interest					
n Intangible drilling costs					
o Other adjustments	NONE				
3 Pre-adjustment AMTI	-47,856,437.	-1,703.	1,567,207.	2,674,582.	NONE
Adjusted current earnings adj					
4 a ACE from line 10 of worksheet	-47,856,437.	-1,703.	1,567,207.	2,674,582.	NONE
b Line 4a less line 3					NONE
c Line 4b multiplied by 75%					NONE
d Total increases over reductions					
e ACE adjustment					NONE
5 Sum of lines 3 and 4e	-47,856,437.	-1,703.	1,567,207.	2,674,582.	NONE
6 AMT NOL deduction					
7 Alternative minimum taxable inc.	-47,856,437.	-1,703.	1,567,207.	2,674,582.	NONE

Form 4626 Detail

Line 2o - Other Adjustments - Contributions Deduction

1.	AMTI (excluding contributions and domestic production activities deduction)	-53,417,169.
2.	Less: NOL carryover	
3.	Plus: Capital Loss carryback	
4.	AMTI without regard to contributions, special deductions, domestic production activities deduction, NOL carrybacks, and capital loss carrybacks	-53,417,169.
5.	Contribution deduction limitation (AMTI x 10%)	NONE
6.	Amount of deductible contributions	3,585,739.
7.	Contribution deduction (Lesser of line 5 or line 6)	NONE

5 Year Contributions carryover

Year ending	Amount Available	Amount Utilized	Carryover to Next Year
12/31/2016	3,585,739.	NONE	3,585,739.
Total	3,585,739.	NONE	3,585,739.

Line 2o - Contributions Adjustment

Regular Contributions	NONE
AMT Contributions	NONE
Contribution adjustment	NONE

Form 4626 Detail

Line 2o - Domestic production activities deduction (DPAD) Adjustment

1a. QPAI from oil-related activities	
b. QPAI from all activities	
2. AMTI limitation	-53,417,169.
3. Lesser of line 1b or line 2	
4. 9% of line 3	
5a. Lesser of line 1a or line 2	
b. Reduction for oil-related QPAI (Line 5a x 3%)	
6. Line 4 minus line 5b	
7. Wage limitation	
8. Lesser of line 6 or line 7	
9. DPAD from cooperatives	
10. Expanded affiliated group (EAG) allocation	
11. DPAD for AMT purposes (Sum of lines 8, 9, and 10)	
12. DPAD for regular tax	
13. AMT adjustment for DPAD	

Form 4626 Detail

Line 6 - Non-SRLY AMT NOL Deduction

Year ending	Original NOL	Amount Available	Amount Used	Carryover to Next year
12/31/2016	53,417,169.	53,417,169.		53,417,169.
Total	53,417,169.	53,417,169.		53,417,169.

Consolidated Schedules
4626 - ACE Worksheet

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1 Pre-adjustment AMTI	-81,419,220.	NONE	3,585,739.	-77,833,481.
ACE depreciation adjustment				
2 a AMT depreciation expense	697,331,191.			697,331,191.
b ACE depreciation expense:				
(1) Post-1994 property	244,943,932.			244,943,932.
(2) Post-1990 property				
(3) Pre-1991 MACRS				
(4) Pre-1991 ACRS				
(5) Sec. 168(f)(1)-(4)				
(6) Other property	451,921,072.			451,921,072.
(7) Total ACE depreciation exp.	696,865,004.			696,865,004.
c ACE depreciation adjustment	466,187.			466,187.
Items included in E&P				
3 a Tax exempt interest income				
b Death benefits from life insurance	-268,623.			-268,623.
c Other life insurance distributions				
d Inside buildup of undist. income	4,986,147.			4,986,147.
e Other items				
f Total increase due to E&P items	4,717,524.			4,717,524.
Items not deductible in E&P				
4 a Certain dividends received	212,200.			212,200.
b Public utility dividends				
c Dividends paid to an ESOP	27,159,171.			27,159,171.
d Nonpatronage dividends				
e Other items				
f Total due to disallowed E&P items	27,371,371.			27,371,371.
Other E&P adjustments				
5 a Intangible drilling costs				
b Circulation expenditures				
c Organizational expenditures				
d LIFO inventory adjustments				
e Installment sales				
f Total other E&P adjustments				
6 Loss disallowance on debts pools				
7 Acquisition expenses				
8 Depletion				
9 Basis adj. from sale of property	NONE			NONE
10 Adjusted current earnings	-48,864,138.	NONE	3,585,739.	-45,278,399.

Consolidated Schedules
4626 - ACE Worksheet

		SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA COMMUNICATIONS HOLDINGS INC 51-0394908	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394
1	Pre-adjustment AMTI	-65,988,499.	10,685,705.	-48,572,420.	9,719,948.	8,185,182.	1,172,240.	48,187,155.	-1,192,180.
	ACE depreciation adjustment								
2 a	AMT depreciation expense		15,840,260.	452,460,178.	46,060,920.	20,960,829.		955,303.	
b	ACE depreciation expense:								
	(1) Post-1994 property		15,840,260.		46,060,920.	21,034,166.		955,303.	
	(2) Post-1990 property								
	(3) Pre-1991 MACRS								
	(4) Pre-1991 ACRS								
	(5) Sec. 168(f)(1)-(4)								
	(6) Other property			451,920,654.					
	(7) Total ACE depreciation exp.		15,840,260.	451,920,654.	46,060,920.	21,034,166.		955,303.	
c	ACE depreciation adjustment			539,524.		-73,337.			
	Items included in E&P								
3 a	Tax exempt interest income								
b	Death benefits from life insurance			-268,623.					
c	Other life insurance distributions								
d	Inside buildup of undist. income			4,986,147.					
e	Other items								
f	Total increase due to E&P items			4,717,524.					
	Items not deductible in E&P								
4 a	Certain dividends received	212,200.							
b	Public utility dividends								
c	Dividends paid to an ESOP	27,159,171.							
d	Nonpatronage dividends								
e	Other items								
f	Total due to disallowed E&P items	27,371,371.							
	Other E&P adjustments								
5 a	Intangible drilling costs								
b	Circulation expenditures								
c	Organizational expenditures								
d	LIFO inventory adjustments								
e	Installment sales								
f	Total other E&P adjustments								
6	Loss disallowance on debts pools								
7	Acquisition expenses								
8	Depletion								
9	Basis adj. from sale of property		NONE						
10	Adjusted current earnings	-38,617,128.	10,685,705.	-43,315,372.	9,719,948.	8,111,845.	1,172,240.	48,187,155.	-1,192,180.

Consolidated Schedules
4626 - ACE Worksheet

		PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483	CLEAN ENERGY ENTERPRISES INC 56-1078443	PSNC BLUE RIDGE CORPORATION 56-1791764	PSNC CARDINAL PIPELINE COMPANY 56-1955423	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
1	Pre-adjustment AMTI	-47,856,437.	-1,703.	1,567,207.	2,674,582.	NONE
	ACE depreciation adjustment					
2 a	AMT depreciation expense	160,717,602.		418.	335,681.	
b	ACE depreciation expense:					
	(1) Post-1994 property	160,717,602.			335,681.	
	(2) Post-1990 property					
	(3) Pre-1991 MACRS					
	(4) Pre-1991 ACRS					
	(5) Sec. 168(f)(1)-(4)					
	(6) Other property			418.		
	(7) Total ACE depreciation exp.	160,717,602.		418.	335,681.	
c	ACE depreciation adjustment					
	Items included in E&P					
3 a	Tax exempt interest income					
b	Death benefits from life insurance					
c	Other life insurance distributions					
d	Inside buildup of undist. income					
e	Other items					
f	Total increase due to E&P items					
	Items not deductible in E&P					
4 a	Certain dividends received					
b	Public utility dividends					
c	Dividends paid to an ESOP					
d	Nonpatronage dividends					
e	Other items					
f	Total due to disallowed E&P items					
	Other E&P adjustments					
5 a	Intangible drilling costs					
b	Circulation expenditures					
c	Organizational expenditures					
d	LIFO inventory adjustments					
e	Installment sales					
f	Total other E&P adjustments					
6	Loss disallowance on debts pools					
7	Acquisition expenses					
8	Depletion					
9	Basis adj. from sale of property					
10	Adjusted current earnings	-47,856,437.	-1,703.	1,567,207.	2,674,582.	NONE

SCANA CORPORATION

Consolidated Schedules
Schedule D

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
	Short-Term Capital Gains and Losses				
1 a	Short-term not on Form 8949				
1 b	Form 8949, Part I, Box A				
2	Form 8949, Part I, Box B				
3	Form 8949, Part I, Box C	-4,979.			-4,979.
4	Gain from installment sales				
5	Gain or loss from Form 8824				
6	Unused capital loss carryover				
7	Net short-term gains and losses	-4,979.			-4,979.
	Long-Term Capital Gains and Losses				
8 a	Long-term not on Form 8949				
8 b	Form 8949, Part II, Box D				
9	Form 8949, Part II, Box E				
10	Form 8949, Part II, Box F	77,345.			77,345.
11	Form 4797 Part I gain	1,646.		-1,646.	
12	Gain from installment sales				
13	Gain or loss from Form 8824				
14	Capital gain distributions	158,428.			158,428.
15	Net long-term gains and losses	237,419.		-1,646.	235,773.
	Summary				
16	Short-term gain over long-term loss				
17	Long-term gain over short-term loss	232,440.		-1,646.	230,794.
18	Net capital gain	232,440.		-1,646.	230,794.

SCANA CORPORATION

Consolidated Schedules
Schedule D

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
Short-Term Capital Gains and Losses								
1 a Short-term not on Form 8949								
1 b Form 8949, Part I, Box A								
2 Form 8949, Part I, Box B								
3 Form 8949, Part I, Box C	-4,979.							
4 Gain from installment sales								
5 Gain or loss from Form 8824								
6 Unused capital loss carryover								
7 Net short-term gains and losses	-4,979.							
Long-Term Capital Gains and Losses								
8 a Long-term not on Form 8949								
8 b Form 8949, Part II, Box D								
9 Form 8949, Part II, Box E								
10 Form 8949, Part II, Box F	77,345.		NONE					
11 Form 4797 Part I gain		NONE					1,646.	
12 Gain from installment sales								
13 Gain or loss from Form 8824								
14 Capital gain distributions	158,428.							
15 Net long-term gains and losses	235,773.	NONE	NONE				1,646.	
Summary								
16 Short-term gain over long-term loss								
17 Long-term gain over short-term loss	230,794.	NONE	NONE				1,646.	
18 Net capital gain	230,794.	NONE	NONE				1,646.	

SCANA CORPORATION

Consolidated Schedules
Schedule D

	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	CLEAN ENERGY ENTERPRISES INC	PSNC BLUE RIDGE CORPORATION	PSNC CARDINAL PIPELINE COMPANY	SCANA CORPORATE SECURITY SERVICES INC
	56-2128483	56-1078443	56-1791764	56-1955423	20-0989017
Short-Term Capital Gains and Losses					
1 a Short-term not on Form 8949					
1 b Form 8949, Part I, Box A					
2 Form 8949, Part I, Box B					
3 Form 8949, Part I, Box C					
4 Gain from installment sales					
5 Gain or loss from Form 8824					
6 Unused capital loss carryover					
7 Net short-term gains and losses					
Long-Term Capital Gains and Losses					
8 a Long-term not on Form 8949					
8 b Form 8949, Part II, Box D					
9 Form 8949, Part II, Box E					
10 Form 8949, Part II, Box F					
11 Form 4797 Part I gain					
12 Gain from installment sales					
13 Gain or loss from Form 8824					
14 Capital gain distributions					
15 Net long-term gains and losses					
Summary					
16 Short-term gain over long-term loss					
17 Long-term gain over short-term loss					
18 Net capital gain					

Schedule D Detail - Capital Gain Distributions

SCANA CORPORATION

Line 14 - Capital Gains Distributions

Name of Payer	Amount
SCANA EXECUTIVE BENEFIT TRUST	158,428.
Total Capital Gains Distributions	158,428.

Consolidated Schedules / Schedule M-3, Part II	Combined Per Inc Stmt	Combined Temporary	Combined Permanent	Combined Per Tax Return	ELIMINATIONS SCANA CORPORATIO Per Inc Stmt	ELIMINATIONS SCANA CORPORATIO Temporary	ELIMINATIONS SCANA CORPORATIO Permanent	ELIMINATIONS SCANA CORPORATIO Per Tax Return
1 Income (loss) from equity method foreign corp.								
2 Gross foreign dividends not previously taxed		34,349.		34,349.				
3 Subpart F, QEF, and similar income inclusions								
4 Section 78 gross-up								
5 Gross foreign distrib. previously taxed								
6 Income (loss) from equity method U.S. corp.	612,397,274.		-612,397,274.		-612,397,274.		612,397,274.	
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.				
8 Minority interest for includible corp.								
9 Income (loss) from U.S. partnerships	3,751,723.	954,029.		4,705,752.				
10 Income (loss) from foreign partnerships								
11 Income (loss) from other pass-through entities	-2,299,688.	-1,380,838.		-3,680,526.				
12 Items relating to reportable transactions								
13 Interest income	49,671,427.	201,001,590.		250,673,017.	-9,434,559.			-9,434,559.
14 Total accrual to cash adjustment								
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.				
16 Mark-to-market income (loss)								
17 Cost of goods sold	2,545,357,167.	72,440,739.		2,472,916,428.	-376,357,089.			-376,357,089.
18 Sales versus lease								
19 Section 481(a) adjustments								
20 Unearned/deferred revenue								
21 Income recognition from long-term contracts								
22 Original issue discount/imputed interest								
23a Income statement gain/loss on sale, exchange, or abandonment	566,889.	-566,889.						
23b Gross cap. gains from Sch. D, excluding amount from pass-through entities		235,773.		235,773.				
23c Gross cap. losses from Sch. D, exc. pass-through ent., abandonment, worthless stock		-4,979.		-4,979.				
23d Net gain/loss reported on Form 4797		-51,771,917.		-51,771,917.				
23e Abandonment losses								
23f Worthless stock losses								
23g Other gain/loss on disposition of assets other than inventory								
24 Capital loss limitation and carryforward used								
25 Other income (loss) items with differences	4,348,156,767.	24,580,638.	222,694.	4,372,960,099.				
26 **Total income (loss) items**	2,445,516,941.	245,574,517.	-612,174,580.	2,078,916,878.	-245,474,744.		612,397,274.	366,922,530.
27 **Total expense/deduction items**	-1,668,755,764.	-1,114,100,827.	212,968,498.	-2,569,888,093.	54,932,991.			54,932,991.
28 Other items with no differences	430,485,648.			430,485,648.	-421,855,521.			-421,855,521.
29a 1120 subgroup reconciliation totals	1,207,246,825.	-868,526,310.	-399,206,082.	-60,485,567.	-612,397,274.		612,397,274.	
29b PC insurance subgroup reconciliation totals								
29c Life insurance subgroup reconciliation totals								
30 **Reconciliation totals**	1,207,246,825.	-868,526,310.	-399,206,082.	-60,485,567.	-612,397,274.		612,397,274.	

SCANA CORPORATION 57-0784499

Consolidated Schedules Schedule M-3, Part II	Adjustments Per Inc Stmt	Temporary	Permanent	Per Tax Return	SCANA CORPORATION Per Inc Stmt	Temporary	Permanent	Per Tax Return
1 Income (loss) from equity method foreign corp.								
2 Gross foreign dividends not previously taxed						34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions								
4 Section 78 gross-up								
5 Gross foreign distrib. previously taxed								
6 Income (loss) from equity method U.S. corp.								
7 U.S. dividends not eliminated in tax consolidation						303,143.		303,143.
8 Minority interest for includible corp.								
9 Income (loss) from U.S. partnerships					3,751,723.	954,029.		4,705,752.
10 Income (loss) from foreign partnerships								
11 Income (loss) from other pass-through entities					-2,299,688.	-1,380,838.		-3,680,526.
12 Items relating to reportable transactions								
13 Interest income					40,236,868.	201,001,590.		241,238,458.
14 Total accrual to cash adjustment								
15 Hedging transactions					-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)								
17 Cost of goods sold					2,169,000,078.	72,440,739.		2,096,559,339.
18 Sales versus lease								
19 Section 481(a) adjustments								
20 Unearned/deferred revenue								
21 Income recognition from long-term contracts								
22 Original issue discount/imputed interest								
23a Income statement gain/loss on sale, exchange, or abandonment					566,889.	-566,889.		
23b Gross cap. gains from Sch. D, excluding amount from pass-through entities						235,773.		235,773.
23c Gross cap. losses from Sch. D, exc. pass-through ent., abandonment, worthless stock						-4,979.		-4,979.
23d Net gain/loss reported on Form 4797						-51,771,917.		-51,771,917.
23e Abandonment losses								
23f Worthless stock losses								
23g Other gain/loss on disposition of assets other than inventory								
24 Capital loss limitation and carryforward used								
25 Other income (loss) items with differences					4,348,156,767.	24,580,638.	222,694.	4,372,960,099.
26 **Total income (loss) items**					2,200,042,197.	245,574,517.	222,694.	2,445,839,408.
27 **Total expense/deduction items**			3,585,739.	3,585,739.	-1,613,822,773.	-1,114,100,827.	216,554,237.	-2,511,369,363.
28 Other items with no differences					8,630,127.			8,630,127.
29a 1120 subgroup reconciliation totals			3,585,739.	3,585,739.	594,849,551.	-868,526,310.	216,776,931.	-56,899,828.
29b PC insurance subgroup reconciliation totals								
29c Life insurance subgroup reconciliation totals								
30 **Reconciliation totals**			3,585,739.	3,585,739.	594,849,551.	-868,526,310.	216,776,931.	-56,899,828.

Schedule M-3, Part II Detail

Line 25 - Other income (loss) items with differences

Description	Income (Loss) Per Income Stmt	Temporary Difference	Permanent Difference	Income (Loss) Per Tax Return
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
GROSS SALES	2,974,321,805.	24,317,336.	60,389.	2,998,699,530.
Subtotal	2,974,321,805.	24,317,336.	60,389.	2,998,699,530.
SCANA ENERGY MARKETING INC				
GROSS SALES	938,014,128.	263,302.		938,277,430.
Subtotal	938,014,128.	263,302.		938,277,430.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
GROSS SALES	435,820,834.		162,305.	435,983,139.
Subtotal	435,820,834.		162,305.	435,983,139.
Total	4,348,156,767.	24,580,638.	222,694.	4,372,960,099.

Schedule M-3, Part II Detail

Line 28 - Other items with no differences

SCANA CORPORATION

SELLING EXPENSES	154,162.
OFFICE SUPPLIES AND EXPENSES	-1,926.
OUTSIDE SERVICES	-2,030.
TAXES AND LICENSES	-287,115.
Subtotal	-136,909.

SCANA SERVICES INC

GAIN ON LAND SALES	269,581.
GROSS SALES	413,279,684.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	452,837.
RENTAL INCOME	735,204.
SELLING EXPENSES	19,408.
ADVERTISING	-814,120.
INSURANCE	-139,629.
MERCHANDISING EXPENSES	-1,301,752.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-21,072,152.
OFFICE SUPPLIES AND EXPENSES	-35,981,453.
OUTSIDE SERVICES	-27,195,321.
RENT EXPENSE	-9,357,222.
TAXES AND LICENSES	-16,528,705.
Subtotal	302,366,360.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

GAIN ON LAND SALES	621,436.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	14,445,489.
RENTAL INCOME	20,964,105.
ADVERTISING	-371,874.
INSURANCE	-7,158,823.
MERCHANDISING EXPENSES	-1,031,448.
OFFICE SUPPLIES AND EXPENSES	-20,537,993.
RENT EXPENSE	-6,587,833.
TAXES AND LICENSES	-230,655,590.
Subtotal	-230,312,531.

Continued on next page

Schedule M-3, Part II Detail

Line 28 - Other items with no differences (Cont'd)

SOUTH CAROLINA FUEL CO INC

GROSS SALES	237,225,342.
OFFICE SUPPLIES AND EXPENSES	-65.
OUTSIDE SERVICES	-236,512.
SALARIES AND WAGES	-3,529.
TAXES AND LICENSES	-2,978.
Subtotal	236,982,258.

SC GENERATING COMPANY INC

GROSS SALES	193,888,768.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-585,541.
RENTAL INCOME	10,903.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-713,109.
OFFICE SUPPLIES AND EXPENSES	-538,492.
OUTSIDE SERVICES	-520,912.
RENT EXPENSE	-78,729.
SALARIES AND WAGES	-1,541,100.
TAXES AND LICENSES	-7,397,963.
Subtotal	182,523,825.

SCANA COMMUNICATIONS HOLDINGS INC

MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-434.
OFFICE SUPPLIES AND EXPENSES	-2,907.
OUTSIDE SERVICES	-11,260.
RENT EXPENSE	-2,400.
SALARIES AND WAGES	-2,400.
TAXES AND LICENSES	-1,230.
Subtotal	-20,631.

SCANA ENERGY MARKETING INC

MISCELLANEOUS INCOME WITHOUT DIFFERENCES	10,217.
ADVERTISING	-11,082,729.
INSURANCE	-264,821.

Continued on next page

Schedule M-3, Part II Detail

Line 28 - Other items with no differences (Cont'd)

OFFICE SUPPLIES AND EXPENSES	-7,529,342.
OUTSIDE SERVICES	-1,912,193.
RENT EXPENSE	-1,974,447.
REPAIRS AND MAINTENANCE	-574,178.
TAXES AND LICENSES	-2,014,177.
Subtotal	-25,341,670.

SERVICECARE INC

MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-24,640.
OFFICE SUPPLIES AND EXPENSES	-4,031.
REPAIRS AND MAINTENANCE	-356.
SALARIES AND WAGES	-2,541.
TAXES AND LICENSES	-359.
Subtotal	-31,927.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

GAIN ON LAND SALES	-56,193.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	12,035,707.
RENTAL INCOME	775,752.
ADVERTISING	-1,030,810.
INSURANCE	-592,872.
MERCHANDISING EXPENSES	-2,130,960.
OFFICE SUPPLIES AND EXPENSES	-7,790,943.
OUTSIDE SERVICES	-2,462,139.
RENT EXPENSE	-1,817,714.
REPAIRS AND MAINTENANCE	-17,874,475.
TAXES AND LICENSES	-14,551,277.
Subtotal	-35,495,924.

CLEAN ENERGY ENTERPRISES INC

OFFICE SUPPLIES AND EXPENSES	-703.
TAXES AND LICENSES	-1,000.
Subtotal	-1,703.

Continued on next page

Schedule M-3, Part II Detail

Line 28 - Other items with no differences (Cont'd)

PSNC BLUE RIDGE CORPORATION

TAXES AND LICENSES	-10,900.
Subtotal	-10,900.

PSNC CARDINAL PIPELINE COMPANY

TAXES AND LICENSES	-34,600.
Subtotal	-34,600.

ELIMINATIONS SCANA CORPORATIO

GAIN ON LAND SALES	-269,581.
GROSS SALES	-719,988,460.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-452,837.
RENTAL INCOME	-6,676,572.
SELLING EXPENSES	-19,408.
ADVERTISING	814,120.
INSURANCE	139,629.
MERCHANDISING EXPENSES	1,478,536.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	35,176,019.
OFFICE SUPPLIES AND EXPENSES	37,231,910.
OUTSIDE SERVICES	27,195,321.
RENT EXPENSE	15,121,806.
REPAIRS AND MAINTENANCE	55,589,061.
SALARIES AND WAGES	116,276,230.
TAXES AND LICENSES	16,528,705.
Subtotal	-421,855,521.

Total	8,630,127.

		Combined				ELIMINATIONS SCANA CORPORATIO			
Consolidated Schedules Schedule M-3, Part III		Per Inc Stmt	Temporary	Permanent	Per Tax Return	Per Inc Stmt	Temporary	Permanent	Per Tax Return
1	U.S. current income tax exp.	35,319,589.		-35,319,589.					
2	U.S. deferred income tax exp.	201,531,407.		-201,531,407.					
3	State and local current income tax exp.	12,961,624.	-11,298,538.		1,663,086.				
4	State and local deferred income tax exp.	20,908,859.	-20,908,859.						
5	Foreign current income tax exp.								
6	Foreign deferred income tax exp.								
7	Foreign withholding taxes								
8	Interest expense	361,995,641.	42,908,253.		404,903,894.	-19,726,271.			-19,726,271.
9	Stock option expense								
10	Other equity-based compensation								
11	Meals and entertainment	2,833,057.		-1,501,983.	1,331,074.				
12	Fines and penalties	-346,594.		346,594.					
13	Judgments, damages, awards, and similar costs	14,456,497.	-2,378,759.		12,077,738.	-5,113,014.			-5,113,014.
14	Parachute payments								
15	Compensation with sect. 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.				
16	Pension and profit-sharing	24,864,595.	-23,804,767.		1,059,828.	-364,871.			-364,871.
17	Other post-retirement benefits	90,740,610.	-4,266,874.		86,473,736.	-29,670,928.			-29,670,928.
18	Deferred compensation	4,528,916.	-4,528,916.						
19	Charitable contribution - cash/tangibles	3,083,562.	497,595.	4,582.	3,585,739.				
20	Charitable contribution - intangible								
21	Charitable contribution limitation/carryforward								
22	Domestic production activities deduction								
23	Current year acquisition or reorg. investment banking fees								
24	Current year acquisition or reorg. legal and accounting fees								
25	Current year acquisition/reorg. other costs								
26	Amortization/impairment of goodwill								
27	Amortization of acquisition and reorg.								
28	Other amort. or impairment write-offs	4,391,015.	7,212,662.		11,603,677.				
29	Reserved								
30	Depletion								
31	Depreciation	352,117,080.	322,789,444.		674,906,524.				
32	Bad debt expense	10,989,039.	-583,897.		10,405,142.	-57,907.			-57,907.
33	Corporate owned life insurance premiums	-624,899.		624,899.					
34	Purchase versus lease								
35	Research and development costs		722,622,385.		722,622,385.				
36	Section 118 exclusion								
37	Other expense/ded. items with differ.	511,355,651.	85,841,098.	26,913,688.	624,110,437.				
38	**Total expense/deduction items**	1,668,755,764.	1,114,100,827.	-212,968,498.	2,569,888,093.	-54,932,991.			-54,932,991.

Consolidated Schedules Schedule M-3, Part III	Adjustments				SCANA CORPORATION			
	Per Inc Stmt	Temporary	Permanent	Per Tax Return	Per Inc Stmt	Temporary	Permanent	Per Tax Return
1 U.S. current income tax exp.					35,319,589.		-35,319,589.	
2 U.S. deferred income tax exp.					201,531,407.		-201,531,407.	
3 State and local current income tax exp.					12,961,624.	-11,298,538.		1,663,086.
4 State and local deferred income tax exp.					20,908,859.	-20,908,859.		
5 Foreign current income tax exp.								
6 Foreign deferred income tax exp.								
7 Foreign withholding taxes								
8 Interest expense					342,269,370.	42,908,253.		385,177,623.
9 Stock option expense								
10 Other equity-based compensation								
11 Meals and entertainment					2,833,057.		-1,501,983.	1,331,074.
12 Fines and penalties					-346,594.		346,594.	
13 Judgments, damages, awards, and similar costs					9,343,483.	-2,378,759.		6,964,724.
14 Parachute payments								
15 Compensation with sect. 162(m) limitation					17,650,115.		-2,505,282.	15,144,833.
16 Pension and profit-sharing					24,499,724.	-23,804,767.		694,957.
17 Other post-retirement benefits					61,069,682.	-4,266,874.		56,802,808.
18 Deferred compensation					4,528,916.	-4,528,916.		
19 Charitable contribution - cash/tangibles					3,083,562.	497,595.	4,582.	3,585,739.
20 Charitable contribution - intangible								
21 Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.			-3,585,739.	-3,585,739.
22 Domestic production activities deduction								
23 Current year acquisition or reorg. investment banking fees								
24 Current year acquisition or reorg. legal and accounting fees								
25 Current year acquisition/reorg. other costs								
26 Amortization/impairment of goodwill								
27 Amortization of acquisition and reorg.								
28 Other amort. or impairment write-offs					4,391,015.	7,212,662.		11,603,677.
29 Reserved								
30 Depletion								
31 Depreciation					352,117,080.	322,789,444.		674,906,524.
32 Bad debt expense					10,931,132.	-583,897.		10,347,235.
33 Corporate owned life insurance premiums					-624,899.		624,899.	
34 Purchase versus lease								
35 Research and development costs						722,622,385.		722,622,385.
36 Section 118 exclusion								
37 Other expense/ded. items with differ.					511,355,651.	85,841,098.	26,913,688.	624,110,437.
38 Total expense/deduction items			-3,585,739.	-3,585,739.	1,613,822,773.	1,114,100,827.	-216,554,237.	2,511,369,363.

Schedule M-3, Part III Detail

Line 18 - Deferred compensation

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SCANA CORPORATION				
Deferred compensation	4,528,916.	-4,528,916.		
Subtotal	4,528,916.	-4,528,916.		
Total	4,528,916.	-4,528,916.		

Line 35 - Research and development costs

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SCANA SERVICES INC				
RESEARCH AND DEVELOPMENT		882,125.		882,125.
Subtotal		882,125.		882,125.
SOUTH CAROLINA ELECTRIC and GAS COMPANY				

Continued on next page

Schedule M-3, Part III Detail

Line 35 - Research and development costs (Cont'd)

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
RESEARCH AND DEVELOPMENT		721,608,322.		721,608,322.
Subtotal		721,608,322.		721,608,322.
SCANA ENERGY MARKETING INC				
RESEARCH AND DEVELOPMENT		131,938.		131,938.
Subtotal		131,938.		131,938.
Total		722,622,385.		722,622,385.

Line 37 - Other expense/deduction items with differences

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SCANA CORPORATION				
DIRECTORS ENDOWMENT	6,411.	-6,411.		
MISCELLANEOUS DEDUCTIONS	2,460,031.	-2,460,031.		

Continued on next page

Schedule M-3, Part III Detail

Line 37 - Other expense/deduction items with differences (Cont'd)

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-4,191,550.	1,004,977.		-3,186,573.
SALARIES AND WAGES	1,746.	369,640.		371,386.
ESOP DIVIDENDS			27,159,171.	27,159,171.
Subtotal	-1,723,362.	-1,091,825.	27,159,171.	24,343,984.

SCANA SERVICES INC

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
REPAIRS AND MAINTENANCE	52,169,644.	-435,305.		51,734,339.
SALARIES AND WAGES	116,276,230.	-13,288,728.		102,987,502.
Subtotal	168,445,874.	-13,724,033.		154,721,841.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
DIRECTORS ENDOWMENT	206,858.	-206,858.		
MISCELLANEOUS DEDUCTIONS	12,049,946.	37,995,832.		50,045,778.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	46,217,761.	5,441,757.		51,659,518.
OUTSIDE SERVICES	14,724,420.	1,682,475.		16,406,895.
REPAIRS AND MAINTENANCE	159,686,858.	55,714,794.		215,401,652.
SALARIES AND WAGES	56,897,111.	-1,489,976.	-218,753.	55,188,382.
CONTRIBUTION IN AID OF CONSTRUCTION		-17,084,713.		-17,084,713.
481A ADJUSTMENT		-4,228,547.		-4,228,547.
Subtotal	289,782,954.	77,824,764.	-218,753.	367,388,965.

Continued on next page

Schedule M-3, Part III Detail

Line 37 - Other expense/deduction items with differences (Cont'd)

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SC GENERATING COMPANY INC				
DIRECTORS ENDOWMENT	9,644.	-9,644.		
INSURANCE	647,872.	6,531.		654,403.
REPAIRS AND MAINTENANCE	11,416,935.	7,308,716.		18,725,651.
Subtotal	12,074,451.	7,305,603.		19,380,054.
SCANA ENERGY MARKETING INC				
DIRECTORS ENDOWMENT	26,306.	-26,306.		
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	2,198,526.	-4,985.		2,193,541.
SALARIES AND WAGES	16,604,698.	-469,467.		16,135,231.
Subtotal	18,829,530.	-500,758.		18,328,772.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
DIRECTORS ENDOWMENT	32,041.	-32,041.		
MISCELLANEOUS DEDUCTIONS		1,803,559.		1,803,559.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	3,211,821.	14,384,232.		17,596,053.
SALARIES AND WAGES	20,702,342.	-128,403.	-26,730.	20,547,209.
Subtotal	23,946,204.	16,027,347.	-26,730.	39,946,821.
Total	511,355,651.	85,841,098.	26,913,688.	624,110,437.

Consolidated Schedules

Cost of Goods Sold

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1 Inventory - beginning	311,778,910.			311,778,910.
2 Purchases	842,119,024.	-111,453,041.		730,665,983.
3 Cost of Labor	-429,280.			-429,280.
4 Addtl. 263A Costs				
5 Other Costs	1,631,550,024.	-264,904,048.		1,366,645,976.
6 Total	2,785,018,678.	-376,357,089.		2,408,661,589.
7 Inventory - Ending	290,480,845.			290,480,845.
8 Cost of Goods Sold	2,494,537,833.	-376,357,089.		2,118,180,744.

Consolidated Schedules
Cost of Goods Sold

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
1 Inventory - beginning		287,791.	171,415,921.	38,266,358.	24,000,296.		25,425,070.	
2 Purchases		62,203.	5,268,408.	-10,885,113.	1,835,212.		688,744,268.	
3 Cost of Labor			-420,319.					
4 Addtl. 263A Costs								
5 Other Costs		74,318,188.	1,084,947,563.	179,355,049.	113,725,200.		144,322,159.	
6 Total		74,668,182.	1,261,211,573.	206,736,294.	139,560,708.		858,491,497.	
7 Inventory - Ending		349,994.	172,900,770.	27,381,245.	25,835,508.		24,739,139.	
8 Cost of Goods Sold		74,318,188.	1,088,310,803.	179,355,049.	113,725,200.		833,752,358.	

	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	CLEAN ENERGY ENTERPRISES INC	PSNC BLUE RIDGE CORPORATION	PSNC CARDINAL PIPELINE COMPANY	SCANA CORPORATE SECURITY SERVICES INC
Consolidated Schedules	56-2128483	56-1078443	56-1791764	56-1955423	20-0989017
Cost of Goods Sold					
1 Inventory - beginning	52,383,474.				
2 Purchases	157,094,046.				
3 Cost of Labor	-8,961.				
4 Addtl. 263A Costs					
5 Other Costs	34,881,865.				
6 Total	244,350,424.				
7 Inventory - Ending	39,274,189.				
8 Cost of Goods Sold	205,076,235.				

Form 1125-A Detail

Line 5 - Other Costs (Cost of Goods Sold)

SCANA SERVICES INC

ELECTRIC - DISTRIBUTION	1,851,944.
ELECTRIC - GENERAL	354,777.
ELECTRIC - PRODUCTION	5,945,786.
ELECTRIC - SALES PROMOTION	1,576,312.
ELECTRIC - TRANSMISSION	452,432.
GAS - CUSTOMER ACCOUNTS	60,665,935.
GAS - DISTRIBUTION	2,133,002.
GAS - PRODUCTION	840,817.
GAS - TRANSMISSION	211,713.
OTHER COSTS	285,470.
Subtotal	74,318,188.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

ELECTRIC - DISTRIBUTION	15,271,035.
ELECTRIC - GENERAL	-2,620,344.
ELECTRIC - PRODUCTION	826,249,729.
ELECTRIC - SALES PROMOTION	6,663,922.
ELECTRIC - TRANSMISSION	9,288,573.
GAS - CUSTOMER ACCOUNTS	53,410,559.
GAS - DISTRIBUTION	9,133,565.
GAS - PRODUCTION	184,185,087.
GAS - TRANSMISSION	235.
OTHER COSTS	-16,634,798.
Subtotal	1,084,947,563.

SOUTH CAROLINA FUEL CO INC

ELECTRIC - PRODUCTION	179,355,049.
Subtotal	179,355,049.

SC GENERATING COMPANY INC

ELECTRIC - GENERAL	4,966.
ELECTRIC - PRODUCTION	113,720,234.
Subtotal	113,725,200.

Continued on next page

Form 1125-A Detail

Line 5 - Other Costs (Cost of Goods Sold) (Cont'd)

SCANA ENERGY MARKETING INC

ELECTRIC - GENERAL	128,082.
ELECTRIC - SALES PROMOTION	144,516.
GAS - CUSTOMER ACCOUNTS	13,131,414.
HEDGING GAIN/LOSS	21,621,405.
OTHER COSTS	197,243.
OTHER STORAGE EXPENSES	31,549,718.
TRANSPORTATION EXPENSES	77,549,781.
Subtotal	144,322,159.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

ELECTRIC - GENERAL	729,521.
ELECTRIC - SALES PROMOTION	2,434,991.
GAS - CUSTOMER ACCOUNTS	12,489,629.
GAS - DISTRIBUTION	14,040,541.
GAS - PRODUCTION	1,350,844.
GAS - TRANSMISSION	3,574,987.
OTHER COSTS	261,352.
Subtotal	34,881,865.

ELIMINATIONS SCANA CORPORATIO

ELECTRIC - DISTRIBUTION	-1,851,944.
ELECTRIC - GENERAL	-354,777.
ELECTRIC - PRODUCTION	-196,415,137.
ELECTRIC - SALES PROMOTION	-1,576,312.
ELECTRIC - TRANSMISSION	-452,432.
GAS - CUSTOMER ACCOUNTS	-60,665,935.
GAS - DISTRIBUTION	-2,133,002.
GAS - PRODUCTION	-840,817.
GAS - TRANSMISSION	-328,222.
OTHER COSTS	-285,470.
Subtotal	-264,904,048.

Total Line 5 - Other Costs (Cost of Goods Sold)	1,366,645,976.

Form 1125-E Detail

Name	Soc Sec #	% Bus	% Com	% Pref	Amount
Compensation of Officers					
SOUTH CAROLINA ELECTRIC and GAS COMPANY	[redacted]				
G T DEVLIN					
K R JACKSON					
R M SENN					
J B ARCHIE					
W J TURNER III					
T D GATLIN					
K B MARSH					
D F KASSIS					
S O SHULER JR					
D R HARRIS					
M K PHALEN					
S L DOZIER					
W K KISSAM					
M R CANNON					
S D BURCH					
J E ADDISON					
R G EDWARDS					
F R HOWARD					
C B LOVE					
J P HUDSON					
S A BYRNE					
P N XANTHAKOS					
J M LANDRETH					
J E SWAN IV					
G S CHAMPION					
W A MCAULAY					
G B RATCHFORD					
S K BOWEN					
M S RANDALL					
H E BARTON JR					
R T LINDSAY					
R A JONES					
A C HIGGINS					
Total - Compensation of Officers					15,144,833.

Compensation of officers deducted on tax return 15,144,833.

SCANA CORPORATION

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Consolidated Schedules - Form 4562				
Consolidated 4562 Summary				
Part I - Section 179 Expense				
2 Sec 179 property placed in Service in current year				
6 Nonlisted property				
7 Listed property				
8 Total elected cost				
9 Tentative deduction				
10 Carryover from 2015				
12 Sec 179 expense deduction				
13 Carryover to 2017				
Part II - Other Depreciation				
14 Special depreciation allowance	309,573,587.			309,573,587.
15 Property subject to 168(f)(1)				
16 ACRS and other depreciation	2,616,055.			2,616,055.
Part III - MACRS				
17 MACRS deduction - prior years	347,024,206.			347,024,206.
19 General Depreciation System				
a. 3-year property				
b. 5-year property	1,964,443.			1,964,443.
c. 7-year property	1,879,486.			1,879,486.
d. 10-year property				
e. 15-year property	6,315,785.			6,315,785.
f. 20-year property	5,527,192.			5,527,192.
g. 25-year property				
h. 27.5-year residential real				
i. 39-year nonresidential real	5,770.			5,770.
20 Alternative Depreciation System				
a. Class life				
b. 12-year				
c. 40-year				
Part IV - Summary				
21 Listed Property				
22 Total depreciation	674,906,524.			674,906,524.
42 Amortization - current year	2,067,441.			2,067,441.
43 Amortization - prior year	9,536,236.			9,536,236.
44 Total Amortization	11,603,677.			11,603,677.

SCANA CORPORATION

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
Consolidated Schedules - Form 4562								
Consolidated 4562 Summary	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
Part I - Section 179 Expense								
2 Sec 179 property placed in Service in current year								
6 Nonlisted property								
7 Listed property								
8 Total elected cost								
9 Tentative deduction								
10 Carryover from 2015								
12 Sec 179 expense deduction								
13 Carryover to 2017								
Part II - Other Depreciation								
14 Special depreciation allowance		6,631,122.	196,749,764.		918,907.		775,871.	
15 Property subject to 168(f)(1)								
16 ACRS and other depreciation			2,285,905.					
Part III - MACRS								
17 MACRS deduction - prior years		8,439,995.	223,119,828.	46,060,920.	18,637,528.		179,432.	
19 General Depreciation System								
a. 3-year property								
b. 5-year property		693,355.	613,002.					
c. 7-year property		75,557.	1,756,409.					
d. 10-year property								
e. 15-year property			3,731,461.					
f. 20-year property			3,662,527.		33,912.			
g. 25-year property								
h. 27.5-year residential real								
i. 39-year nonresidential real		231.	2,296.					
20 Alternative Depreciation System								
a. Class life								
b. 12-year								
c. 40-year								
Part IV - Summary								
21 Listed Property								
22 Total depreciation		15,840,260.	431,921,192.	46,060,920.	19,590,347.		955,303.	
42 Amortization - current year		493,942.	1,344,971.		3,743.		169,268.	
43 Amortization - prior year		1,645,176.	6,771,800.		98,050.		929,379.	
44 Total Amortization		2,139,118.	8,116,771.		101,793.		1,098,647.	

SCANA CORPORATION

	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	CLEAN ENERGY ENTERPRISES INC	PSNC BLUE RIDGE CORPORATION	PSNC CARDINAL PIPELINE COMPANY	SCANA CORPORATE SECURITY SERVICES INC
Consolidated Schedules - Form 4562					
Consolidated 4562 Summary	56-2128483	56-1078443	56-1791764	56-1955423	20-0989017
Part I - Section 179 Expense					
2 Sec 179 property placed in Service in current year					
6 Nonlisted property					
7 Listed property					
8 Total elected cost					
9 Tentative deduction					
10 Carryover from 2015					
12 Sec 179 expense deduction					
13 Carryover to 2017					
Part II - Other Depreciation					
14 Special depreciation allowance	104,497,923.				
15 Property subject to 168(f)(1)					
16 ACRS and other depreciation	330,150.				
Part III - MACRS					
17 MACRS deduction - prior years	50,586,503.				
19 General Depreciation System					
a. 3-year property					
b. 5-year property	658,086.				
c. 7-year property	47,520.				
d. 10-year property					
e. 15-year property	2,584,324.				
f. 20-year property	1,830,753.				
g. 25-year property					
h. 27.5-year residential real					
i. 39-year nonresidential real	3,243.				
20 Alternative Depreciation System					
a. Class life					
b. 12-year					
c. 40-year					
Part IV - Summary					
21 Listed Property					
22 Total depreciation	160,538,502.				
42 Amortization - current year	55,517.				
43 Amortization - prior year	91,831.				
44 Total Amortization	147,348.				

Consolidated Schedules
Form 4797

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Column (g) Section 1231 Gains/Losses				
From Form 4797, line 2	-53,778,949.			-53,778,949.
Gain from Form 4684, line 39				
Gain from Form 6252				
From Form 8824				
Gain from Form 4797, line 32				
Total Section 1231 gain (loss)	-53,778,949.			-53,778,949.
Nonrecaptured prior year losses				
Net Section 1231 gain				
Ordinary Gains and Losses				
From Form 4797, line 10	-1,782,435.			-1,782,435.
Section 1231 loss	-53,780,595.		1,646.	-53,778,949.
Section 1231 gain				
Gain from Form 4797, line 31	3,789,467.			3,789,467.
From Form 4684				
From Form 6252				
From Form 8824				
Net ordinary gain or (loss)	-51,773,563.		1,646.	-51,771,917.

SCANA CORPORATION 57-0784499

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
Consolidated Schedules Form 4797	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
Column (g) Section 1231 Gains/Losses								
From Form 4797, line 2		NONE	-39,991,222.		-3,530,135.		1,646.	
Gain from Form 4684, line 39								
Gain from Form 6252								
From Form 8824								
Gain from Form 4797, line 32								
Total Section 1231 gain (loss)		NONE	-39,991,222.		-3,530,135.		1,646.	
Nonrecaptured prior year losses								
Net Section 1231 gain								
Ordinary Gains and Losses								
From Form 4797, line 10		-696,096.	-1,015,942.					
Section 1231 loss			-39,991,222.		-3,530,135.			
Section 1231 gain								
Gain from Form 4797, line 31			2,982,956.					
From Form 4684								
From Form 6252								
From Form 8824								
Net ordinary gain or (loss)		-696,096.	-38,024,208.		-3,530,135.			

	PUBLIC SERVICE COMPANY OF NORTH	CLEAN ENERGY ENTERPRISES INC	PSNC BLUE RIDGE CORPORATION	PSNC CARDINAL PIPELINE COMPANY	SCANA CORPORATE SECURITY SERVICES INC
Consolidated Schedules	56-2128483	56-1078443	56-1791764	56-1955423	20-0989017
Form 4797					
Column (g) Section 1231 Gains/Losses					
From Form 4797, line 2	-10,259,238.				
Gain from Form 4684, line 39					
Gain from Form 6252					
From Form 8824					
Gain from Form 4797, line 32					
Total Section 1231 gain (loss)	-10,259,238.				
Nonrecaptured prior year losses					
Net Section 1231 gain					
Ordinary Gains and Losses					
From Form 4797, line 10	-70,397.				
Section 1231 loss	-10,259,238.				
Section 1231 gain					
Gain from Form 4797, line 31	806,511.				
From Form 4684					
From Form 6252					
From Form 8824					
Net ordinary gain or (loss)	-9,523,124.				

Form 4797, Page 1 Detail SCANA SERVICES INC

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS	07/01/2010	07/01/2016		233,786.	233,786.	NONE
Part I 4797 Gains and Losses						NONE

Form 4797, Page 1 Detail SOUTH CAROLINA ELECTRIC and GAS COMPANY

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS			1,190,826.	34,778,065.	75,960,113.	-39,991,222.
Part I 4797 Gains and Losses						-39,991,222.

Form 4797, Page 1 Detail SC GENERATING COMPANY INC

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS	VARIOUS	07/01/2016		2,089,073.	5,619,208.	-3,530,135.
Part I 4797 Gains and Losses						-3,530,135.

Form 4797, Page 1 Detail SCANA ENERGY MARKETING INC

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
FURNITURE	06/30/2010	06/30/2016	1,646.	18,333.	18,333.	1,646.
Part I 4797 Gains and Losses						1,646.

Form 4797, Page 1 Detail PUBLIC SERVICE COMPANY OF NORTH CAROLINA

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
Various	03/01/2015	07/01/2016	42,268.	7,072,408.	17,373,914.	-10,259,238.
Part I 4797 Gains and Losses						-10,259,238.

Form 4797, Page 1 Detail SCANA SERVICES INC

Line 10 - Ordinary Gains and Losses

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS2	07/01/2015	07/01/2016		391,554.	1,087,650.	-696,096.
Part II 4797 Ordinary Gains and Losses						-696,096.

Form 4797, Page 1 Detail SOUTH CAROLINA ELECTRIC and GAS COMPANY

Line 10 - Ordinary Gains and Losses

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS			1,368.	43,944.	1,061,254.	-1,015,942.
Part II 4797 Ordinary Gains and Losses						-1,015,942.

Form 4797, Page 1 Detail PUBLIC SERVICE COMPANY OF NORTH CAROLINA

Line 10 - Ordinary Gains and Losses

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
Various	VARIOUS	07/01/2016	62,720.	5,392.	138,509.	-70,397.
Part II 4797 Ordinary Gains and Losses						-70,397.

Form 6765 Page 1 Detail

Controlled Group Member Statement

Corporation Name	Share of Credit
SOUTH CAROLINA ELECTRIC and GAS COMPANY	28,137,821.
SC GENERATING COMPANY INC	7,586.

Form 7004 - Affiliated Group Members

Name	Employer ID	Name	Employer ID
SCANA SERVICES INC	57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695
SOUTH CAROLINA FUEL CO INC	57-0691209	SC GENERATING COMPANY INC	57-0784498
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908	SCANA ENERGY MARKETING INC	57-0850977
SERVICECARE INC	57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	56-2128483
CLEAN ENERGY ENTERPRISES INC	56-1078443	PSNC BLUE RIDGE CORPORATION	56-1791764
PSNC CARDINAL PIPELINE COMPANY	56-1955423	SCANA CORPORATE SECURITY SERVICES INC	20-0989017

Consolidated Schedules Form 8903	Combined Oil-related Pro	Combined All Activities	ELIMINATIONS SCANA CORPORATIO Oil-related Pro	ELIMINATIONS SCANA CORPORATIO All Activities	Adjustments Oil-related Pro	Adjustments All Activities	SCANA CORPORATION Oil-related Pro	SCANA CORPORATION All Activities
1 Domestic production gross receipts		4,497,365,433.						4,497,365,433.
2 Allocable cost of goods sold		4,338,581,720.						4,338,581,720.
3 Deductions and losses		374,307,595.						374,307,595.
4 Pro rata share								
5 Add lines 2 through 4		4,712,889,315.						4,712,889,315.
6 Subtract line 5 from line 1		-215,523,882.						-215,523,882.
7 Qualified prod activities inc from pass-through								
8 Add lines 6 and 7.								
9 Amount allocated to beneficiaries of the estate or trust.								
10 Qualified production activities inc								
11 Income limitation								
12 Enter the smaller of line 10b or line 11								
13 Enter 9% of line 12								
14 a Enter the smaller of line 10a or line 12								
b Reduction for oil-related QPAI								
15 Subtract line 14b from line 13								
16 Form W-2 wages								
17 Form W-2 wages from pass-through								
18 Add lines 16 and 17								
19 Amount allocated to beneficiaries of the estate or trust.								
20 Estates and trusts, subtract line 19 from line 18.								
21 Form W-2 wage limitation								
22 Enter the smaller of line 15 or line 21								
23 DPAD from cooperatives								
24 Expanded affiliated group allocation								
25 Domestic production activities ded								

	SCANA CORPORATION		SCANA SERVICES INC		SOUTH CAROLINA ELECTRIC and GAS COMPANY		SOUTH CAROLINA FUEL CO INC	
	57-0784499		57-1092169		57-0248695		57-0691209	
Consolidated Schedules **Form 8903**	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities
1 Domestic production gross receipts						4,497,365,433.		
2 Allocable cost of goods sold						4,338,581,720.		
3 Deductions and losses						374,307,595.		
4 Pro rata share								
5 Add lines 2 through 4						4,712,889,315.		
6 Subtract line 5 from line 1						-215,523,882.		
7 Qualified prod activities inc from pass-through								
8 Add lines 6 and 7.								
9 Amount allocated to beneficiaries of the estate or trust.								
10 Qualified production activities inc								
11 Income limitation								
12 Enter the smaller of line 10b or line 11								
13 Enter 9% of line 12								
14 a Enter the smaller of line 10a or line 12								
b Reduction for oil-related QPAI								
15 Subtract line 14b from line 13								
16 Form W-2 wages								
17 Form W-2 wages from pass-through								
18 Add lines 16 and 17								
19 Amount allocated to beneficiaries of the estate or trust.								
20 Estates and trusts, subtract line 19 from line 18.								
21 Form W-2 wage limitation								
22 Enter the smaller of line 15 or line 21								
23 DPAD from cooperatives								
24 Expanded affiliated group allocation								
25 Domestic production activities ded								

	SC GENERATING COMPANY INC		SCANA COMMUNICATIONS HOLDINGS INC		SCANA ENERGY MARKETING INC		SERVICECARE INC	
	57-0784498		51-0394908		57-0850977		57-1007394	
Consolidated Schedules	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities
Form 8903	--------------	--------------	--------------	--------------	--------------	--------------	--------------	--------------
1 Domestic production gross receipts								
2 Allocable cost of goods sold								
3 Deductions and losses								
4 Pro rata share								
5 Add lines 2 through 4								
6 Subtract line 5 from line 1								
7 Qualified prod activities inc from pass-through								
8 Add lines 6 and 7.								
9 Amount allocated to beneficiaries of the estate or trust.								
10 Qualified production activities inc								
11 Income limitation								
12 Enter the smaller of line 10b or line 11								
13 Enter 9% of line 12								
14 a Enter the smaller of line 10a or line 12								
b Reduction for oil-related QPAI								
15 Subtract line 14b from line 13								
16 Form W-2 wages								
17 Form W-2 wages from pass-through								
18 Add lines 16 and 17								
19 Amount allocated to beneficiaries of the estate or trust.								
20 Estates and trusts, subtract line 19 from line 18.								
21 Form W-2 wage limitation								
22 Enter the smaller of line 15 or line 21								
23 DPAD from cooperatives								
24 Expanded affiliated group allocation								
25 Domestic production activities ded								

Consolidated Schedules Form 8903	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483 Oil-related Pro	All Activities	CLEAN ENERGY ENTERPRISES INC 56-1078443 Oil-related Pro	All Activities	PSNC BLUE RIDGE CORPORATION 56-1791764 Oil-related Pro	All Activities	PSNC CARDINAL PIPELINE COMPANY 56-1955423 Oil-related Pro	All Activities
1 Domestic production gross receipts								
2 Allocable cost of goods sold								
3 Deductions and losses								
4 Pro rata share								
5 Add lines 2 through 4								
6 Subtract line 5 from line 1								
7 Qualified prod activities inc from pass-through								
8 Add lines 6 and 7.								
9 Amount allocated to beneficiaries of the estate or trust.								
10 Qualified production activities inc								
11 Income limitation								
12 Enter the smaller of line 10b or line 11								
13 Enter 9% of line 12								
14 a Enter the smaller of line 10a or line 12								
b Reduction for oil-related QPAI								
15 Subtract line 14b from line 13								
16 Form W-2 wages								
17 Form W-2 wages from pass-through								
18 Add lines 16 and 17								
19 Amount allocated to beneficiaries of the estate or trust.								
20 Estates and trusts, subtract line 19 from line 18.								
21 Form W-2 wage limitation								
22 Enter the smaller of line 15 or line 21								
23 DPAD from cooperatives								
24 Expanded affiliated group allocation								
25 Domestic production activities ded								

SCANA CORPORATE SECURITY SERVICES INC
20-0989017

Consolidated Schedules	Oil-related Pro	All Activities
Form 8903		
1 Domestic production gross receipts		
2 Allocable cost of goods sold		
3 Deductions and losses		
4 Pro rata share		
5 Add lines 2 through 4		
6 Subtract line 5 from line 1		
7 Qualified prod activities inc from pass-through		
8 Add lines 6 and 7.		
9 Amount allocated to beneficiaries of the estate or trust.		
10 Qualified production activities inc		
11 Income limitation		
12 Enter the smaller of line 10b or line 11		
13 Enter 9% of line 12		
14a Enter the smaller of line 10a or line 12		
b Reduction for oil-related QPAI		
15 Subtract line 14b from line 13		
16 Form W-2 wages		
17 Form W-2 wages from pass-through		
18 Add lines 16 and 17		
19 Amount allocated to beneficiaries of the estate or trust.		
20 Estates and trusts, subtract line 19 from line 18.		
21 Form W-2 wage limitation		
22 Enter the smaller of line 15 or line 21		
23 DPAD from cooperatives		
24 Expanded affiliated group allocation		
25 Domestic production activities ded		

Form 8916-A, Part I Detail

Line 6 - Other items with differences

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
OTHER COSTS		-16,857,064.		-16,857,064.
Subtotal		-16,857,064.		-16,857,064.
SOUTH CAROLINA FUEL CO INC				
ELECTRIC - PRODUCTION	235,135,917.	-55,780,868.		179,355,049.
Subtotal	235,135,917.	-55,780,868.		179,355,049.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
OTHER COSTS	363,432.	-164,793.		198,639.
Subtotal	363,432.	-164,793.		198,639.
Total	235,499,349.	-72,802,725.		162,696,624.

Form 8916-A, Part I Detail

Line 7 - Other items with no differences

SCANA SERVICES INC

ELECTRIC - DISTRIBUTION	1,851,944.
ELECTRIC - GENERAL	354,777.
ELECTRIC - PRODUCTION	5,945,786.
ELECTRIC - SALES PROMOTION	1,576,312.
ELECTRIC - TRANSMISSION	452,432.
GAS - CUSTOMER ACCOUNTS	60,665,935.
GAS - DISTRIBUTION	2,133,002.
GAS - PRODUCTION	840,817.
GAS - TRANSMISSION	211,713.
OTHER COSTS	285,470.
Subtotal	74,318,188.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

ELECTRIC - DISTRIBUTION	15,271,035.
ELECTRIC - GENERAL	-2,620,344.
ELECTRIC - PRODUCTION	826,249,729.
ELECTRIC - SALES PROMOTION	6,663,922.
ELECTRIC - TRANSMISSION	9,288,573.
GAS - CUSTOMER ACCOUNTS	53,410,559.
GAS - DISTRIBUTION	9,133,565.
GAS - PRODUCTION	184,185,087.
GAS - TRANSMISSION	235.
PURCHASES	3,783,559.
VACATION EXPENSE	-420,319.
Subtotal	1,104,945,601.

SC GENERATING COMPANY INC

ELECTRIC - GENERAL	4,966.
ELECTRIC - PRODUCTION	113,720,234.
Subtotal	113,725,200.

Continued on next page

Form 8916-A, Part I Detail

Line 7 - Other items with no differences (Cont'd)

SCANA ENERGY MARKETING INC

ELECTRIC - GENERAL	128,082.
ELECTRIC - SALES PROMOTION	144,516.
GAS - CUSTOMER ACCOUNTS	13,131,414.
OTHER COSTS	120,236.
OTHER STORAGE EXPENSES	31,549,718.
PURCHASES	689,430,199.
TRANSPORTATION EXPENSES	77,549,781.
Subtotal	812,053,946.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

ELECTRIC - GENERAL	729,521.
ELECTRIC - SALES PROMOTION	2,434,991.
GAS - CUSTOMER ACCOUNTS	12,489,629.
GAS - DISTRIBUTION	14,040,541.
GAS - PRODUCTION	1,350,844.
GAS - TRANSMISSION	3,574,987.
PURCHASES	170,203,331.
VACATION EXPENSE	-8,961.
Subtotal	204,814,883.

ELIMINATIONS SCANA CORPORATIO

ELECTRIC - DISTRIBUTION	-1,851,944.
ELECTRIC - GENERAL	-354,777.
ELECTRIC - PRODUCTION	-196,415,137.
ELECTRIC - SALES PROMOTION	-1,576,312.
ELECTRIC - TRANSMISSION	-452,432.
GAS - CUSTOMER ACCOUNTS	-60,665,935.
GAS - DISTRIBUTION	-2,133,002.
GAS - PRODUCTION	-840,817.
GAS - TRANSMISSION	-328,222.
OTHER COSTS	-285,470.
PURCHASES	-111,453,041.
Subtotal	-376,357,089.

Total	1,933,500,729.

Form 8916-A, Part II Detail

Line 5 - Other Interest Income

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SCANA CORPORATION				
INTEREST INCOME	1,595,218.	-1,382,225.		212,993.
Subtotal	1,595,218.	-1,382,225.		212,993.
SCANA SERVICES INC				
INTEREST INCOME	13,954.			13,954.
Subtotal	13,954.			13,954.
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
BOOK INTEREST CAPITALIZED	26,082,377.	203,397,097.		229,479,474.
INTEREST INCOME	5,862,694.			5,862,694.
Subtotal	31,945,071.	203,397,097.		235,342,168.

Continued on next page

Form 8916-A, Part II Detail

Line 5 - Other Interest Income (Cont'd)

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SC GENERATING COMPANY INC				
BOOK INTEREST CAPITALIZED		-31,785.		-31,785.
INTEREST INCOME	54,017.			54,017.
Subtotal	54,017.	-31,785.		22,232.
SCANA COMMUNICATIONS HOLDINGS INC				
INTEREST INCOME	6,321.			6,321.
Subtotal	6,321.			6,321.
SCANA ENERGY MARKETING INC				
INTEREST INCOME	221.			221.
Subtotal	221.			221.

Continued on next page

Form 8916-A, Part II Detail

Line 5 - Other Interest Income (Cont'd)

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
BOOK INTEREST CAPITALIZED	3,302,769.	-1,013,022.		2,289,747.
INTEREST INCOME	3,269,780.			3,269,780.
Subtotal	6,572,549.	-1,013,022.		5,559,527.
ELIMINATIONS SCANA CORPORATIO				
INTEREST INCOME	-13,954.			-13,954.
Subtotal	-13,954.			-13,954.
Total	40,173,397.	200,970,065.		241,143,462.

Form 8916-A, Part III Detail

Line 4 - Other Interest Expense

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SCANA CORPORATION				
OTHER INTEREST EXPENSE	54,743,724.	-3,597.		54,740,127.
Subtotal	54,743,724.	-3,597.		54,740,127.
SCANA SERVICES INC				
OTHER INTEREST EXPENSE	462.			462.
Subtotal	462.			462.
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
OTHER INTEREST EXPENSE	248,048,905.	42,604,735.		290,653,640.
Subtotal	248,048,905.	42,604,735.		290,653,640.
SOUTH CAROLINA FUEL CO INC				
OTHER INTEREST EXPENSE	1,787,247.			1,787,247.
Subtotal	1,787,247.			1,787,247.

Continued on next page

Form 8916-A, Part III Detail

Line 4 - Other Interest Expense (Cont'd)

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SC GENERATING COMPANY INC				
OTHER INTEREST EXPENSE	14,133,651.	-482,617.		13,651,034.
Subtotal	14,133,651.	-482,617.		13,651,034.
SCANA ENERGY MARKETING INC				
OTHER INTEREST EXPENSE	-12,434.			-12,434.
Subtotal	-12,434.			-12,434.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
OTHER INTEREST EXPENSE	24,154,282.	789,732.		24,944,014.
Subtotal	24,154,282.	789,732.		24,944,014.
ELIMINATIONS SCANA CORPORATIO				
OTHER INTEREST EXPENSE	-1,903,795.			-1,903,795.
Subtotal	-1,903,795.			-1,903,795.
Total	340,952,042.	42,908,253.		383,860,295.

Federal Elections

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Description: Election RECURRING ITEMS EXCEPTION

Regulation Reference: 461(h)

Pursuant to Internal Revenue Code Section 461(h) and Regulation 1.461-5(D), the taxpayer has elected to use the recurring items exception to the economic performance rules of IRS Section 461(h), and intends for this election to apply to all subsidiaries included in the consolidated return. The election is adopted for all items satisfying the conditions outlined in Section 461(h) that are incurred in the taxpayer's trade or business.

Federal Elections

Description: Election DEPRECIATION UNDER IRC 168(k)

Regulation Reference: 168(k)

PURSUANT TO SECTION 168(K)(2)(C)(III), SCANA CORPORATION, AS AGENT FOR EACH OF ITS SUBSIDIARIES LISTED BELOW, HEREBY ELECTS NOT TO APPLY THE SPECIAL DEPRECIATION ALLOWANCE FOR CERTAIN PROPERTY ACQUIRED AFTER JANUARY 1, 2008, THAT IS PROVIDED UNDER SECTION 168(K) OF THE CODE, AND INTENDS FOR THIS ELECTION TO APPLY TO THE CLASSES OF QUALIFIED PROPERTY SEPARATELY LISTED ON A COMPANY BY COMPANY BASIS FOR THE TAX YEAR 2016. FOR SOUTH CAROLINA FUEL CO INC, THE ELECTION APPLIES TO ALL CLASSES OF QUALIFIED PROPERTY.

Federal Elections

Description: Election DEPRECIATION PRIOR TO JANUARY 1

Regulation Reference: 167

SCANA Corporation elects under Section 1.167(a)-12(e)(2) of the Regulations on behalf of itself and the following named subsidiaries to apply Section 1.167(a)-12 of the Regulations for depreciation of property placed in service prior to January 1, 1971 for the taxable year 2016. This election is for South Carolina Electric and Gas and Public Service Company of North Carolina, Inc.

Electronic Filing Information: PDF attachments Included in this Return

Tax Year: 2016
Name: SCANA CORPORATION
Return No: C0000ZT6
Jurisdiction: Federal
No of Attachments: 3

PDF Attachment Description	PDF File Name	File Size
Form 4466 - Corp Application for Quick Refund of Overpayment of Estimated Tax	C0000ZT6_FE_Form 4466-Corporation Application for Quick Refund.pdf	78,815
Form1098C	C0000ZT6_FE_Form 1098C_SCEG.pdf	188,524
SCANA_2016_Attachment_Sec_118_exclusion	C0000ZT6_FE_SCANA_2016_Attachment_Sec 118 exclusion.pdf	45,602

09/28/2017 11:48:27

Form **4466** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Corporation Application for Quick Refund of Overpayment of Estimated Tax

▶ Information about Form 4466 and its instructions is available at *www.irs.gov/form4466.*

OMB No 1545-0123

For calendar year 2016 or tax year beginning , 20 , and ending , 20

Name	Employer identification number
SCANA Corporation	57-0784499
Number, street, and room or suite no (If a P O. box, see instructions)	Telephone number (optional)
220 Operation Way	
City or town, state, and ZIP code	
Cayce, SC 29033-3701	803-217-9315

Check type of return to be filed (see instructions).

[X] Form 1120 [ ] Form 1120-C [ ] Form 1120-F [ ] Form 1120-L [ ] Form 1120-PC [ ] Other ▶

1	Estimated income tax paid during the tax year			1	81,000,000
2	Overpayment of income tax from prior year credited to this year's estimated tax			2	
3	Total Add lines 1 and 2			3	81,000,000
4	Enter total tax from the appropriate line of your tax return See instructions	4	6,000,000		
5a	Personal holding company tax, if any, included on line 4	5a			
b	Estimated refundable tax credit for federal tax on fuels	5b			
6	Total. Add lines 5a and 5b	6			
7	Expected income tax liability for the tax year Subtract line 6 from line 4			7	6,000,000
8	**Overpayment of estimated tax.** Subtract line 7 from line 3 If this amount is at least 10% of line 7 and at least $500, the corporation is eligible for a quick refund Otherwise, do not file this form See instructions			8	75,000,000

Record of Estimated Tax Deposits

Date of deposit	Amount	Date of deposit	Amount
06/15/2016	81,000,000		

Sign Here

Under penalties of perjury, I declare that I have examined this application, including any accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete

▶ James E Swan Signature   2/1/17 Date   ▶ CONTROLLER Title

General Instructions

Section references are to the Internal Revenue Code

Who May File

Any corporation that overpaid its estimated tax for the tax year may apply for a quick refund if the overpayment is

- At least 10% of the expected tax liability and
- At least $500.

The overpayment is the excess of the estimated income tax the corporation paid during the tax year over the final income tax liability expected for the tax year, at the time this application is filed

If members of an affiliated group paid their estimated income tax on a consolidated basis or expect to file a consolidated return for the tax year, only the common parent corporation may file Form 4466 If members of the group paid estimated income tax separately, the member who claims the overpayment must file Form 4466.

Note: Form 4466 is not considered a claim for credit or refund.

☐ CORRECTED (if checked)

DONEE'S name, street address, city or town, state or province, country, ZIP or foreign postal code, and telephone no [redacted]	1 Date of contribution 5-4-2016 2a Odometer mileage 221,648	OMB No 1545-1959 **2016** Form **1098-C**	Attachment Sequence No **155A** **Contributions of Motor Vehicles, Boats, and Airplanes**
	2b Year 2009 · 2c Make Chevrolet · 2d Model CK 20753		
DONEE'S federal identification number 57-6000314 · DONOR'S identification number 57-0248695	3 Vehicle or other identification number 1GCHK49K99E152318		
DONOR'S name South Carolina Electric & Gas Co Street address (including apt no) 100 SCANA Parkway	4a ☐ Donee certifies that vehicle was sold in arm's length transaction to unrelated party 4b Date of sale		**Copy B**
City or town, state or province, country, and ZIP or foreign postal code Cayce, SC 29033	4c Gross proceeds from sale (see instructions) $		**For Donor**

5a ☑ Donee certifies that vehicle will not be transferred for money, other property, or services before completion of material improvements or significant intervening use

5b ☐ Donee certifies that vehicle is to be transferred to a needy individual for significantly below fair market value in furtherance of donee's charitable purpose

5c Donee certifies the following detailed description of material improvements or significant intervening use and duration of use

6a Did you provide goods or services in exchange for the vehicle? . . . . ▶ Yes ☐ No ☑

6b Value of goods and services provided in exchange for the vehicle
$

6c Describe the goods and services, if any, that were provided. If this box is checked, donee certifies that the goods and services consisted solely of intangible religious benefits . . . . . ▶ ☐

7 Under the law, the donor may not claim a deduction of more than $500 for this vehicle if this box is checked . . . . ▶ ☐

In order to take a deduction of more than $500 for this contribution, you must attach this copy to your federal tax return.

Unless box 5a or 5b is checked, your deduction cannot exceed the amount in box 4c.

Form **1098-C** www.irs.gov/form1098c Department of the Treasury - Internal Revenue Service

SCANA Corporation

57-0784499

Tax Year 2016

Schedule M-3, Page 3, Part 3, line 36
Section 118 Exclusion

Non Standard Service Fund $3,464,164 –Municipalities reimburse SCE&G costs for installing non-standard services. Typical work performed is for public benefit generally related to safety and beautification.

South Carolina Department of Transportation $9,029,018 – SCE&G is reimbursed cost for construction services provided to the SCDOT. These services typically include relocation projects involving removing and installing new SCE&G poles and/or lines and gas pipe to accommodate SCDOT improvement projects.

FORMS (TAX)

FORM NUMBER

SC 1120

JURISDICTION

SOUTH CAROLINA

MONTH	YEAR
	2016

TYPE

INCOME

COMPANY

CONSOLIDATED

September 28, 2017

HAND DELIVERED

South Carolina Department of Revenue
Income Tax Division
P. O. Box 125
Columbia, SC 29214

Re: SCANA Corporation and Subsidiaries, No. 57-0784499
File No. 20119164-6, Form SC1120, Return for Year
Ended December 31, 2016

Gentlemen:

Enclosed herewith please find our Form SC1120, 2016 South Carolina Corporate Income Tax Return for SCANA Corporation and Subsidiaries. At the time of filing our Tentative Tax Return in March, you extended the time for filing our final return to October 15, 2017. Our return herein shows overpayments of $ 1,264,634.00 which should be applied to estimated tax.

If you have any questions, please do not hesitate to contact the undersigned.

Yours very truly,

James E. Swan IV
Controller

S.C.
DEPT. OF REVENUE
SEP 29 2017
RECEIVED COLUMBIA
TAXPAYER'S ASSISTANCE

Enclosure

September 28, 2017

HAND DELIVERED

South Carolina Department of Revenue
Income Tax Division
P. O. Box 125
Columbia, SC 29214

Re: SCANA Corporation and Subsidiaries, No. 57-0784499
File No. 20119164-6, Form SC1120, Return for Year
Ended December 31, 2016

Gentlemen:

Enclosed herewith please find our Form SC1120, 2016 South Carolina Corporate Income Tax Return for SCANA Corporation and Subsidiaries. At the time of filing our Tentative Tax Return in March, you extended the time for filing our final return to October 15, 2017. Our return herein shows overpayments of $ 1,264,634.00 which should be applied to estimated tax.

If you have any questions, please do not hesitate to contact the undersigned.

Yours very truly,

James E. Swan IV
Controller

Enclosure

SCANA CORPORATION & SUBSIDIARIES					
EMPLOYER ID. NUMBER 57-0784499					
SC CORPORATION INCOME TAX RETURN					
FOR THE YEAR ENDED DECEMBER 31, 2016					
DESCRIPTION					
FORM SC1120					
2017 LICENSE FEE & ATTACHMENTS FOR CREDIT					
SC1120 BY ENTITY					
SC1120-TC CORPORATE TAX CREDITS					
SCHEDULE OF TAXABLE INCOME & LICENSE FEE BY ENTITY					
SC SCH TC-4 NEW JOBS CREDIT					
SC SCH TC-6 INFRASTRUCTURE CREDIT					
SC SCH TC-11 CAPITAL INVESTMENT CREDIT					
SC SCH TC-11-R RECAPTURE OF CAPITAL INVESTMENT CREDIT					
SC SCH TC-18 RESEARCH EXPENSES CREDIT					
DISCLOSURE OF TC-11 CREDITS					
FORM 8275 DISCLOSURE AND WAIVER STATEMENT- RE EIZ INVESTMENT TAX CREDITS					
STATE CARRYFORWARD SCHEDULE					
OFFICERS AND DIRECTORS					

1062 6D4935 4.000

THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN
Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120
(Rev. 9/2/16)
3091

SC FILE # 20119164-6

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-0784499

NAME SCANA CORPORATION
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ [ ] Address [ ] Accounting Period
[ ] Officers

Attach complete copy of Federal Return
[X] Check here if you filed a federal or state extension

Check if ▶ [ ] Initial Return ▶ [X] Consolidated Return (Complete Schedule M)
▶ [ ] Amended Return [ ] Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.
▶ [ ] Merged ▶ [ ] Reorganized ▶ [ ] Final

County or Counties in SC Where Property is Located: VARIOUS

City	Audit Location	State
CAYCE		SC

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶ 4497365433	▶ 2136524698	JAMES E SWAN IV	803 217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

Line	Description		Amount
1.	Federal Taxable Income per federal tax return	▶ 1.	-62,862,156 00
2.	Net Adjustment from line 12, Schedule A and B Stmt 1	2.	116,884,872 00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2) Stmt 4	▶ 3.	54,022,716 00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	59,164,551 00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.	00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	59,164,551 00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	2,958,228 00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.	00
9.	Balance (line 7 less line 8)	9.	2,958,228 00
10.	Credit Carryover (line 7, Schedule C) ▶ 3,956,806 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.	< 2,958,228 00 >
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	00
12.	Interest on DISC-deferred tax liability 00 ; or Foreign Trade Deferred Tax Liability 00	12.	00
13.	Total tax and/or interest (add lines 11 and 12)	13.	00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s: see instructions) ▶ 00		
	(b) Paid by Declaration ▶ 7,400,000 00 (c) Paid with Extension ▶ 00		
	(d) Credit from Line 29b ▶ 00		
	Refundable Credits: (e) Ammonia Additive ▶ 00		
	(f) Milk Credit ▶ 00		
15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.	7,400,000 00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	00
17.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00		
	(c) Declaration Penalty Due (Attach SC2220) ▶ 00		
	(See penalty and interest instructions.) Enter Total	▶ 17.	00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	00
19.	OVERPAYMENT (line 15 less line 13) 7,400,000 00 To be applied as follows:		
	(a) Estimated Tax ▶ 1,264,634 00 (b) License Fee ▶ 6,135,366 00 (c) REFUNDED ▶		00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

30911036

THO 6D4936 2.000

SC1120 Page 2

PART II COMPUTATION OF LICENSE FEE

20. Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20	5262670500 00
21. FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer) Stmt 8	▶21	16,810,733 00
22. Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	8,675,367 00
23. Balance (line 21 less line 22)	23.	8,135,366 00
24. Payments: (a) Paid with Extension ▶ 2,000,000 00		
(b) Credit from line 19b ▶ 6,135,366 00		
25. Total Payments (add line 24a and 24b)	25.	8,135,366 00
26. Balance of Fee Due (line 23 less line 25)	▶26.	00
27. (a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (See penalty and interest instructions.) Enter Total	▶27.	00
28. TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29. OVERPAYMENT (line 25 less line 23) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED	▶	00
30. GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.	00

SCHEDULE A AND B ADDITIONS TO FEDERAL TAXABLE INCOME

1. Taxes on or Measured By Income 1.
2. Federal Net Operating Loss 2.
3. 3.
4. 4.
5. Other Additions (attach schedule) 5.
6. Total Additions (add lines 1 through 5) 6.

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7. Interest On Obligations Of The U.S. 7
8. 8.
9. 9.
10. Other Deductions (attach schedule) 10.
11. Total Deductions (add lines 7 through 10) 11.
12. Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120 12.

SCHEDULE C SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1. Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2. Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return.	2.	6,915,034
3. Total Credits (add lines 1 and 2)	3.	6,915,034
4. Tax (line 9, Part 1, SC1120)	4.	2,958,228
5. Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	2,958,228
6. Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7. Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	3,956,806

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer — Officer's title: CONTROLLER — Email: jswan@scana.com

Officer's printed name: JAMES E SWAN IV — Date: 9/28/17 — Telephone Number: 803 217 9000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐ Preparer's Printed Name

Paid Preparer's Use Only

Preparer's signature — Date — Check if self-employed ☐ — Preparer's Telephone Number

Firm's name (or yours if self-employed) and address: INTERNALLY PREPARED, 220 OPERATION WAY, CAYCE, SC — PTIN or FEIN — ZIP Code 29033-3701

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature — Date

30912034

1062

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE
THO APPLICATION FOR AUTOMATIC EXTENSION OF TIME TO FILE CORPORATION TAX RETURN

SC1120-T
(Rev. 7/22/16)
3096

GENERAL INSTRUCTIONS

A corporation requesting an extension of time must submit an SC1120-T and pay ALL the income tax shown to be due on the corporate tax return, plus ALL of the corporate license fee due, on or before the original due date of the corporate tax return. A corporation may file SC1120-T online.

Payment Only: Submit payment electronically for free at MyDORWAY.dor.sc.gov.
(No paper document is required if paying by this method)

The Department may allow an extension not to exceed six months to file a corporate tax return. If the corporation has not fulfilled its filing requirements for any previous period, the Department cannot grant an extension, and the corporate tax return will be delinquent if not filed by the original due date. The Department will not send notice of the invalid extension.

The Department will accept a federal extension. Only one SC1120-T is needed to extend a South Carolina consolidated corporate tax return. A single payment may be made for the entire consolidated group. You do not need to list each member included in the consolidated return. The Department will accept a federal extension if all corporations in the consolidated group have filed or are included in a federal extension.

If the amount remitted with the extension fails to reflect at least 90% of the tax to be paid for the period granted by the extension, an underpayment penalty applies from the date the tax was originally due on the difference between the amount remitted and the tax to be paid for the period until paid in full.

Request an extension and pay online through MyDORWAY at MyDORWAY.dor.sc.gov or mail SC1120-T to: **SC Department of Revenue, Corporation, Columbia SC 29214-0006. Include Business Name and FEIN on both the form and the check.**

6S4901 1.000

PLEASE DO NOT CUT. SUBMIT ENTIRE PAGE.

1062

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE
THO APPLICATION FOR AUTOMATIC EXTENSION OF TIME TO FILE CORPORATION TAX RETURN
SC1120-T
(Rev. 7/22/16)
3096

SC CORPORATE FILE #	INCOME ACCT PERIOD END (MM-YY)
20119164-6	12-16
57-0784499	

FEIN

S.C. DEPT. OF REVENUE
MAR 31 2017
RECEIVED COLUMBIA
TAXPAYER ASSISTANCE

CLIP CHECK HERE

Corporate Name and Address

SCANA CORPORATION
220 OPERATION WAY

CAYCE SC 29033-3701

PLACE AN 'X' IN THE BOX IF:

- [ ] First-time filer who has not filed a CL-1
- [ ] S Corporation
- [X] Consolidated Return
- [ ] Bank or Savings & Loan
- [ ] Utility or Electric Cooperative

1. Estimated Tax Due (Do not enter less than zero) 0.00

2. Total Capital and Paid in Surplus - SEE ATTACHED ~~0.00~~ x .001 plus $15.00 but not less than $25.00 Minimum License Fee ..... 2,000,000.00 (Do not enter less than zero)

3. Balance Due Remitted ...... 2,000,000.00 (line 1 plus line 2)

30961049 201191646 570784499 1216 00000000000 00200000000 6

Extension

SCANA CORPORATION AND SUBSIDIARIES
2017 LICENSE FEE

Federal EIN					2017 License Fee
57-0784499	SCANA Corporation				
	Capital -	$2,341,403,986	@ 1 Mill + $15		$2,341,419
57-1092169	SCANA Services, Inc.				
	Capital -	$6,850,916	@ 1 Mill + $15		$6,866
57-0248695	South Carolina Electric & Gas Company				
	Gross Receipts -	$2,977,109,482	@ 3 Mills	8,931,328	
	True Value -	$5,353,148,040	@ 1 Mill	5,353,148	14,284,476
	Less: SC Code 12-20-105 Tax Credit				(400,000)
57-0691209	South Carolina Fuel Company, Inc.				
	Capital -	$2,696,226	@ 1 Mill + $15		$2,711
57-0784498	South Carolina Generating Company, Inc.				
	True Value -	$163,211,048	@ 1 Mill		$163,211
	Less: SC Code 12-20-105 Tax Credit				(140,000)
57-0850977	SCANA Energy Marketing, Inc.				
	Capital -	$12,508,040	@ 1 Mill + $15		$12,523
56-2128483	Public Service Company of NC				
	Gross Receipts -	$0	@ 3 Mills	0	
	True Value -	$0	@ 1 Mill	0	25
56-1078443	Clean Energy Enterprises, Inc.				
	Capital -	$2,000	@ 1 Mill + $15		25
20-0989017	SCANA Corporate Security Services, Inc.				
	Capital -	$1,000	@ 1 Mill + $15		25
			TOTAL		$16,271,281
			LESS	Estimated June 2016 income tax payment	(7,400,000)
			LESS	SC tax credits	(6,871,281)
					$2,000,000

SCANA CORPORATION AND SUBSIDIARIES
2017 LICENSE FEE

Federal EIN					2017 License Fee
57-0784499	SCANA Corporation				
	Capital -	$2,341,403,986	@ 1 Mill + $15		$2,341,419
57-1092169	SCANA Services, Inc.				
	Capital -	$6,726,949	@ 1 Mill + $15		$6,742
57-0248695	South Carolina Electric & Gas Company				
	Gross Receipts -	$2,977,109,482	@ 3 Mills	8,931,328	
	True Value -	$5,353,148,040	@ 1 Mill	5,353,148	14,284,476
	Less: SC Code 12-20-105 Tax Credit				(400,000)
57-0691209	South Carolina Fuel Company, Inc.				
	Capital -	$2,696,226	@ 1 Mill + $15		$2,711
57-0784498	South Carolina Generating Company, Inc.				
	True Value -	$163,211,048	@ 1 Mill		$163,211
	Less: SC Code 12-20-105 Tax Credit				(140,000)
57-0850977	SCANA Energy Marketing, Inc.				
	Capital -	$12,084,107	@ 1 Mill + $15		$12,099
56-2128483	Public Service Company of NC				
	Gross Receipts	$0	@ 3 Mills	0	
	True Value -	$0	@ 1 Mill	0	25
56-1078443	Clean Energy Enterprises, Inc.				
	Capital -	$2,000	@ 1 Mill + $15		25
20-0989017	SCANA Corporate Security Services, Inc.				
	Capital -	$1,000	@ 1 Mill + $15		25
		TOTAL			$16,270,733
		LESS		Estimated June 2016 income tax payment	(7,400,000)
		LESS		SC tax credits	(6,871,281)
					$1,999,452

TO: SC DEPARTMENT OF REVENUE

FROM: JAMES E SWAN IV
CONTROLLER

SUBJECT: WAIVER OF STATUTE OF LIMITATIONS
SCANA CORPORATION (57-0784499)

PURSUANT TO REVENUE RULING #96-11, SCANA CORPORATION AND SUBSIDIARIES ARE EXECUTING A LIMITED WAIVER OF THE STATUTE OF LIMITATIONS UNDER SECTION 12-54-85 ALLOWING THE DEPARTMENT OF REVENUE THE RIGHT TO ASSESS THE TAX FOR A PERIOD COMMENCING WITH THE DATE THAT THE RETURN ON WHICH THE CREDIT IS CLAIMED IS FILED AND ENDING THREE YEARS AFTER THE COMPANY NOTIFIES THE DEPARTMENT OF REVENUE THAT THE INFRASTRUCTURE HAS BEEN BUILT.

THE WAIVER IS BEING EXECUTED FOR, AND IS LIMITED EXCLUSIVELY REGARDING, THE 2016 LICENSE FEE CREDIT TAKEN ON THE FOLLOWING PROJECTS WHICH ARE NOT COMPLETE AT THE TIME OF THIS RETURN FILING.

[redacted]

NO WAIVER IS BEING EXECUTED FOR THOSE PROJECTS WHICH WERE COMPLETE AT THE TIME OF THIS RETURN FILING. PLEASE SEE THE ATTACHED COMPLETION LETTER FROM THE FOLLOWING:

[redacted]

JAMES E SWAN IV

TO: SC DEPARTMENT OF REVENUE

FROM: JAMES E SWAN IV
CONTROLLER

SUBJECT: EXTINGUISHING THE EXTENSION OF WAIVER OF STATUTE OF LIMITATIONS
SCANA CORPORATION (57-0784499) AND SUBIDIARIES

SCANA CORPORATION AND SUBSIDIARIES HEREBY, VIA THE MAILING OF THIS NOTICE AND ATTACHMENTS, CEASE THE EXTENSION OF WAIVER OF THE STATUTE OF LIMITATIONS GRANTED PURSUANT TO SC REVENUE RULING #96-11 FOR THE 2014, 2015, AND 2016 LICENSE FEE LIABILITY ON THE CORPORATE INCOME TAX RETURN FILED FOR CALENDAR YEAR 2013, 2014, AND 2015 AS THE INFRASTRUCTURE PROJECTS WITH RESPECT TO WHICH CREDIT AGAINST LICENSE TAX UNDER SECTION 12-20-105 WAS TAKEN HAS BEEN COMPLETED.

ONE PROJECT IS NOW COMPLETE AND IS DETAILED BELOW. PLEASE SEE THE ATTACHED LETTER. WE ARE NOT CONTINUING TO EXECUTE THE WAIVER FOR THIS PROJECTS.

[redacted]

TWO PROJECTS ARE NOT COMPLETE AND ARE DETAILED BELOW. PLEASE SEE THE ATTACHED LETTERS. WE ARE CONTINUING TO EXECUTE A WAIVER FOR THESE PROJECTS THAT BEGAN PRIOR TO 2016.

[redacted]

JAMES E SWAN IV

Aiken County
County Administrator's Office

Remembering the Past, Preparing for the Future

J Clay Killian
County Administrator

May 9, 2017

Mr. R. Scott Neely
Economic Development and
Local Government Manager
SCANA Corporation
132 Langley Dam Road
Warrenville, SC 29851

Re: [redacted]

Dear Mr. Neely:

[redacted]

Aiken County appreciates SCE&G's assistance with this project. We look forward to partnering with you again on future projects in our County.

Sincerely,

J. Clay Killian
County Administrator

Orangeburg
All-America County

COUNTY OF ORANGEBURG

P.O. DRAWER 9000, ORANGEBURG, S.C. 29116-9000
TELEPHONE 803/533-6101
WWW.ORANGEBURGCOUNTY.ORG

COUNTY ADMINISTRATOR
HAROLD M. YOUNG

COUNCIL MEMBERS
JOHNNIE WRIGHT, SR., CHM.
JANIE COOPER-SMITH, VICE CHAIR
CLYDE B. LIVINGSTON
HEYWARD H. LIVINGSTON
WILLIE B. OWENS

JOHNNY RAVENELL
HARRY WIMBERLY

April 27, 2017

Mr. R. Scott Neely
Economic Development and
Local Government Manager
SCANA Corporation
132 Langley Dam Road
Warrenville, SC 29851

Re: [redacted]

Dear Mr. Neely:

[redacted]

Orangeburg County appreciates SCE&G's assistance with this project, and we look forward to partnering with you again on future projects in our County.

Sincerely,

Harold M. Young
County Administrator

BUILDING A BRIGHTER FUTURE FOR OUR CITIZENS

Colleton County, South Carolina

May 18, 2017

Mr. Brad Samuel
SCANA Corporation
Economic Development & Local Government Representative
P.O. Box 1168
Beaufort, South Carolina 29901

[redacted]

Dear Mr. Samuel:

[redacted]

Sincerely,

J. Kevin Griffin
County Administrator

P.O. Box 157, Walterboro, South Carolina 29488 Tel: (843) 549-1725/5221 Fax: (843) 549-7215

Chesterfield County
Economic Development Board
Kim Burch
Executive Director
www.chesterfieldcounty.org

PO Box 192 / 105 Green Street
Chesterfield, South Carolina 29709
Phone: 843-623-6500
Fax: 843-623-3167
kburchatccc@shtc.net

June 1, 2017

Robert C. Holland
SCE&G
1812 N. Irby St.
Florence, SC 29501

Dear Mr. Holland:

[redacted]

Yours truly,

Cherry G McCoy

Cherry G, McCoy
Sr. Project Manager
Chesterfield County Economic Development
843 623-6500
843 307-2922 (cell)
Mccoy275@shtc.net

FAIRFIELD ECONOMIC DEVELOPMENT

The Natural Resource for Business in South Carolina

May 2, 2017

Ms. Morgan Harrell
SCANA Corporation
100 SCANA Parkway, MC D132
Cayce, SC 29033-3701

[redacted]

Dear Ms. Harrell:

[redacted]

As back up information I have attached the most recent progress report.

Best regards,

Ty Davenport
Director Economic Development
Fairfield County

OFFICE OF
COUNTY COUNCIL OF HAMPTON COUNTY
201 Jackson Avenue, West
Hampton, South Carolina 29924

Tel: (803) 914-2103
Fax: (803) 914--2107

May 21, 2017,

Mr. Brad Samuel
SCANA Corporation
Economic Development & Local Government Representative
108 Robert Smalls Parkway
P.O. Box 1168
Beaufort, SC 29901

[redacted]

Dear Mr. Samuel:

[redacted]

Again, Hampton County appreciates SCE&G's assistance with this project, and we look forward to partnering with you again on future projects in our Region. Thank you in advance for your support. Should you have any questions or require additional information, please do not hesitate to contact me.

Sincerely,

Rose D. Elliott

Rose D. Elliott, County Administrator
Hampton County

DORCHESTER COUNTY
ECONOMIC DEVELOPMENT

May 8, 2017

Anna Pinckney
Economic Development & Local Government Manager
SCANA Corporation
PO Box 760
Charleston, SC 29402

Dear Anna:

[redacted]

We certainly appreciate all of your help with our economic development efforts. We would not be nearly as successful without your assistance.

Sincerely,

John Truluck
Economic Development Director

402 N. Main Street • Summerville, SC 29483
(843) 875-9109 • Fax (843) 821-9994
www.dorchesterforbusiness.com • info@dorchesterforbusiness.com

Dillon County
SOUTH CAROLINA

Tonny McNeil
Executive Director
101 E. Main St.
PO Drawer 911
Dillon, SC 29536
843.774.1402
FAX 843.841.3872
www.dilloncounty.org
E-MAIL
dilloncoecondev@bellsouth.net

May 1, 2017

Mr. Bobby Holland
Economic Development Representative
SCE&G
1812 North Irby Street
Florence, SC 29501

Dear Mr. Holland,

[redacted]

Sincerely,

Tonny McNeil
Executive Director
Dillon County Economic Development

1062

6D4935 4.000

THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120
(Rev. 9/2/16)
3091

SC FILE # 20119164-6

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-0784499

NAME SCANA CORPORATION
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ ☐ Address ☐ Accounting Period
☐ Officers

Attach complete copy of Federal Return
☒ Check here if you filed a federal or state extension

Check if ▶ ☐ Initial Return ▶ ☐ Consolidated Return (Complete Schedule M)
▶ ☐ Amended Return ☐ Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ ☐ Merged ▶ ☐ Reorganized ▶ ☐ Final

County or Counties in SC Where Property is Located:

City	Audit Location	State
CAYCE		SC

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶	▶	JAMES E SWAN IV SWAN IV	803 217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

Line	Description	Ref	Amount
1.	Federal Taxable Income per federal tax return	▶ 1.	-65,988,499 00
2.	Net Adjustment from line 12, Schedule A and B	2.	-15,820 00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	-66,004,319 00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	-66,004,319 00
5.	LESS: South Carolina net operating loss carryover, if applicable Stmt 1	5.	00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	-66,004,319 00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.	00
9.	Balance (line 7 less line 8)	9.	00
10.	Credit Carryover (line 7, Schedule C) ▶ 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.	00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	00
12.	Interest on DISC-deferred tax liability 00; or Foreign Trade Deferred Tax Liability 00	12.	00
13.	Total tax and/or interest (add lines 11 and 12)	13.	00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ 00		
	(b) Paid by Declaration ▶ 7,400,000 00 (c) Paid with Extension ▶ 00		
	(d) Credit from Line 29b ▶ 00		
	Refundable Credits: (e) Ammonia Additive ▶ 00		
	(f) Milk Credit ▶ 00		
15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.	7,400,000 00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	00
17.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (c) Declaration Penalty Due (Attach SC2220) ▶ 00 (See penalty and interest instructions.) Enter Total	▶ 17.	00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	00
19.	OVERPAYMENT (line 15 less line 13) 7,400,000 00 To be applied as follows: (a) Estimated Tax ▶ 7,400,000 00 (b) License Fee ▶ 00 (c) REFUNDED ▶		00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

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1062 6D4935 4.000

THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120 (Rev. 9/2/16) 3091

SC FILE # 20119164-6

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-1092169

NAME SCANA SERVICES INC
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ [ ] Address [ ] Accounting Period
[ ] Officers

Attach complete copy of Federal Return
[X] Check here if you filed a federal or state extension

Check if ▶ [ ] Initial Return ▶ [ ] Consolidated Return (Complete Schedule M)
▶ [ ] Amended Return [ ] Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ [ ] Merged ▶ [ ] Reorganized ▶ [ ] Final

County or Counties in SC Where Property is Located: LEXINGTON

Audit Location: City CAYCE State SC

Total Gross Receipts ▶ 413279684
Total cost of depreciable personal property in SC ▶ 310559314
Audit Contact JAMES E SWAN IV
Telephone Number 8032179000

PART I COMPUTATION OF INCOME TAX LIABILITY

1.	Federal Taxable Income per federal tax return	▶ 1.	10,685,705 00
2.	Net Adjustment from line 12, Schedule A and B	2.	969,541 00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	11,655,246 00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	11,444,344 00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.	00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	11,444,344 00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	572,217 00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.	00
9.	Balance (line 7 less line 8)	9.	572,217 00
10.	Credit Carryover (line 7, Schedule C) ▶ 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.	20,000 00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	552,217 00
12.	Interest on DISC-deferred tax liability 00 ; or Foreign Trade Deferred Tax Liability 00	12.	00
13.	Total tax and/or interest (add lines 11 and 12)	13.	552,217 00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ 00; (b) Paid by Declaration ▶ 00; (c) Paid with Extension ▶ 00; (d) Credit from Line 29b ▶ 00; Refundable Credits: (e) Ammonia Additive ▶ 00; (f) Milk Credit ▶ 00		
15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.	00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	552,217 00
17.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (c) Declaration Penalty Due (Attach SC2220) ▶ 00 (See penalty and interest instructions.) Enter Total	▶ 17.	00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	00
19.	OVERPAYMENT (line 15 less line 13) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) License Fee ▶ 00 (c) REFUNDED ▶		00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

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THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year

SC 1120
(Rev. 9/2/16)
3091

SC FILE #

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-0248695

NAME SOUTH CAROLINA ELECTRIC AND GAS COMPA
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ ☐ Address ☐ Accounting Period
☐ Officers

Attach complete copy of Federal Return
☐ Check here if you filed a federal or state extension

Check if ▶ ☐ Initial Return ▶ ☐ Consolidated Return (Complete Schedule M)
▶ ☐ Amended Return ☐ Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ ☐ Merged ▶ ☐ Reorganized ▶ ☐ Final

County or Counties in SC Where Property is Located:

City | Audit Location | State

Total Gross Receipts ▶ 2998699530
Total cost of depreciable personal property in SC ▶
Audit Contact JAMES SWAN IV
Telephone Number 803-217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

1.	Federal Taxable Income per federal tax return	▶ 1.	-29,736,612 00
2.	Net Adjustment from line 12, Schedule A and B	2.	112,567,176 00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	82,830,564 00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	80,683,679 00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.	00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	80,683,679 00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	4,034,184 00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.	00
9.	Balance (line 7 less line 8)	9.	4,034,184 00
10.	Credit Carryover (line 7, Schedule C) ▶ 2,859,170 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.	4,034,184 00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	00
12.	Interest on DISC-deferred tax liability 00 ; or Foreign Trade Deferred Tax Liability 00	12.	00
13.	Total tax and/or interest (add lines 11 and 12)	13.	00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ 00 (b) Paid by Declaration ▶ 00 (c) Paid with Extension ▶ 00 (d) Credit from Line 29b ▶ 00 Refundable Credits: (e) Ammonia Additive ▶ 00 (f) Milk Credit ▶ 00		
15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.	00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	00
17.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (c) Declaration Penalty Due (Attach SC2220) ▶ 00 (See penalty and interest instructions.) Enter Total	▶ 17.	00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	00
19.	OVERPAYMENT (line 15 less line 13) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) License Fee ▶ 00 (c) REFUNDED ▶		00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

30911036

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THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120 (Rev. 9/2/16) 3091

SC FILE #

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-0691209

NAME SOUTH CAROLINA FUEL CO INC
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701

Change of ▶ ☐ Address ☐ Accounting Period ☐ Officers

Attach complete copy of Federal Return
☐ Check here if you filed a federal or state extension

Check if ▶ ☐ Initial Return ▶ ☐ Consolidated Return (Complete Schedule M)
▶ ☐ Amended Return ☐ Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ ☐ Merged ▶ ☐ Reorganized ▶ ☐ Final

County or Counties in SC Where Property is Located: VARIOUS

City	Audit Location	State
Cayce		SC

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶ 237225342	▶ 1114511261	James E. Swan IV	803-217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

1.	Federal Taxable Income per federal tax return.	▶ 1.	9,719,948 00
2.	Net Adjustment from line 12, Schedule A and B	2.	00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	9,719,948 00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	9,719,948 00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.	00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	9,719,948 00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	485,997 00
8.	Less tax deferred on income from foreign trade receipts (see instructions).	▶ 8.	00
9.	Balance (line 7 less line 8)	9.	485,997 00
10.	Credit Carryover (line 7, Schedule C) ▶ 00 Nonrefundable credits (line 5, Schedule C).	▶ 10.	00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	485,997 00
12.	Interest on DISC-deferred tax liability 00 ; or Foreign Trade Deferred Tax Liability 00	12.	00
13.	Total tax and/or interest (add lines 11 and 12)	13.	485,997 00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ 00 (b) Paid by Declaration ▶ 00 (c) Paid with Extension ▶ 00 (d) Credit from Line 29b ▶ 00 Refundable Credits: (e) Ammonia Additive ▶ 00 (f) Milk Credit ▶ 00		
15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.	00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	485,997 00
17.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (c) Declaration Penalty Due (Attach SC2220) ▶ 00 (See penalty and interest instructions.) Enter Total.	▶ 17.	00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	485,997 00
19.	OVERPAYMENT (line 15 less line 13) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) License Fee ▶ 00 (c) REFUNDED ▶ 00		

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

30911036

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THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120
(Rev. 9/2/16)
3091

SC FILE #

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-0784498

NAME SC GENERATING COMPANY INC
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ ☐ Address ☐ Accounting Period
☐ Officers

Attach complete copy of Federal Return
☐ Check here if you filed a federal or state extension

Check if ▶ ☐ Initial Return ▶ ☐ Consolidated Return (Complete Schedule M)
▶ ☐ Amended Return ☐ Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.
▶ ☐ Merged ▶ ☐ Reorganized ▶ ☐ Final

County or Counties in SC Where Property is Located: BERKELEY

City	Audit Location	State
CAYCE		SC

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶ 193888768	▶ 701977895	JAMES E. SWAN IV	(803) 217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

		Line	Amount	
1.	Federal Taxable Income per federal tax return	▶ 1.	9,555,628	00
2.	Net Adjustment from line 12, Schedule A and B	2.	1,498,416	00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	11,054,044	00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	11,054,044	00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.		00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	11,054,044	00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	552,702	00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.		00
9.	Balance (line 7 less line 8)	9.	552,702	00
10.	Credit Carryover (line 7, Schedule C) ▶ ______ 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.	< 1,680	00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	551,022	00
12.	Interest on DISC-deferred tax liability ______ 00 ; or Foreign Trade Deferred Tax Liability ______ 00	12.		00
13.	Total tax and/or interest (add lines 11 and 12)	13.	551,022	00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ ______ 00			
	(b) Paid by Declaration ▶ ______ 00 (c) Paid with Extension ▶ ______ 00			
	(d) Credit from Line 29b ▶ ______ 00			
	Refundable Credits: (e) Ammonia Additive ▶ ______ 00			
	(f) Milk Credit ▶ ______ 00			
15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.		00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	551,022	00
17.	(a) Interest Due ▶ ______ 00 (b) Late File/Pay Penalty Due ▶ ______ 00			
	(c) Declaration Penalty Due (Attach SC2220) ▶ ______ 00			
	(See penalty and interest instructions.) Enter Total.	▶ 17.		00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	551,022	00
19.	OVERPAYMENT (line 15 less line 13) ______ 00 To be applied as follows:			
	(a) Estimated Tax ▶ ______ 00 (b) License Fee ▶ ______ 00 (c) REFUNDED ▶			00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

30911036

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THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN
Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120 (Rev. 9/2/16) 3091

SC FILE # 20119164-6

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-0850977

NAME SCANA ENERGY MARKETING INC
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ [ ] Address [ ] Accounting Period
[ ] Officers

Attach complete copy of Federal Return
[X] Check here if you filed a federal or state extension

Check if ▶ [ ] Initial Return ▶ [ ] Consolidated Return (Complete Schedule M)
▶ [ ] Amended Return [ ] Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ [ ] Merged ▶ [ ] Reorganized ▶ [ ] Final

County or Counties in SC Where Property is Located: RICHLAND

Audit Location: City CAYCE State SC

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶ 938277430	▶ 9476228	JAMES E SWAN IV	(803)217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

1. Federal Taxable Income per federal tax return	▶ 1.	48,187,155	00
2. Net Adjustment from line 12, Schedule A and B	2.	1,567,144	00
3. Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	49,754,299	00
4. If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	13,459,035	00
5. LESS: South Carolina net operating loss carryover, if applicable	5.		00
6. South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	13,459,035	00
7. TAX: Multiply amount on line 6 by 5% (.05)	7.	672,952	00
8. Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.		00
9. Balance (line 7 less line 8)	9.	672,952	00
10. Credit Carryover (line 7, Schedule C) ▶ ____ 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.		00
11. Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	672,952	00
12. Interest on DISC-deferred tax liability ____ 00 ; or Foreign Trade Deferred Tax Liability ____ 00	12.		00
13. Total tax and/or interest (add lines 11 and 12)	13.	672,952	00
14. Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see Instructions) ▶ ____ 00 (b) Paid by Declaration ▶ ____ 00 (c) Paid with Extension ▶ ____ 00 (d) Credit from Line 29b ▶ ____ 00 Refundable Credits: (e) Ammonia Additive ▶ ____ 00 (f) Milk Credit ▶ ____ 00			
15. Total Payments and Refundable Credits (add lines 14a through 14f)	15.		00
16. Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	672,952	00
17. (a) Interest Due ▶ ____ 00 (b) Late File/Pay Penalty Due ▶ ____ 00 (c) Declaration Penalty Due (Attach SC2220) ▶ ____ 00 (See penalty and interest instructions.) Enter Total	▶ 17.		00
18. TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.		00
19. OVERPAYMENT (line 15 less line 13) ____ 00 To be applied as follows: (a) Estimated Tax ▶ ____ 00 (b) License Fee ▶ ____ 00 (c) REFUNDED ▶			00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

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1062

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THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120
(Rev. 9/2/16)
3091

SC FILE #

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 57-1007394

NAME SERVICECARE INC
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701

Change of ▶ [ ] Address [ ] Accounting Period
[ ] Officers

Attach complete copy of Federal Return
[X] Check here if you filed a federal or state extension

Check if ▶ [ ] Initial Return ▶ [ ] Consolidated Return (Complete Schedule M)
▶ [ ] Amended Return [ ] Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ [ ] Merged ▶ [ ] Reorganized ▶ [X] Final

County or Counties in SC Where Property is Located:

City	Audit Location	State
CAYCE		SC

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶	▶	JAMES E SWAN IV	803-217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

1.	Federal Taxable Income per federal tax return	▶ 1.	-1,192,180	00
2.	Net Adjustment from line 12, Schedule A and B	2.		00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	-1,192,180	00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	-1,192,180	00
5.	LESS: South Carolina net operating loss carryover, if applicable Stmt 1	5.		00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	-1,192,180	00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.		00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.		00
9.	Balance (line 7 less line 8)	9.		00
10.	Credit Carryover (line 7, Schedule C) ▶ [00] Nonrefundable credits (line 5, Schedule C)	▶ 10.		00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.		00
12.	Interest on DISC-deferred tax liability [00]; or Foreign Trade Deferred Tax Liability [00]	12.		00
13.	Total tax and/or interest (add lines 11 and 12)	13.		00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ [00]; (b) Paid by Declaration ▶ [00]; (c) Paid with Extension ▶ [00]; (d) Credit from Line 29b ▶ [00]; Refundable Credits: (e) Ammonia Additive ▶ [00]; (f) Milk Credit ▶ [00]			
15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.		00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.		00
17.	(a) Interest Due ▶ [00] (b) Late File/Pay Penalty Due ▶ [00] (c) Declaration Penalty Due (Attach SC2220) ▶ [00] (See penalty and interest instructions.) Enter Total	▶ 17.		00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.		00
19.	OVERPAYMENT (line 15 less line 13) [00] To be applied as follows: (a) Estimated Tax ▶ [00] (b) License Fee ▶ [00] (c) REFUNDED ▶			00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

30911036

1062

6D4935 4.000

THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120
(Rev. 9/2/16)
3091

SC FILE #

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 56-2128483
NAME PUBLIC SERVICE COMPANY OF NORTH CAROL INCORPORTATED
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701

Change of ▶ ☐ Address ☐ Accounting Period ☐ Officers

Attach complete copy of Federal Return
☐ Check here if you filed a federal or state extension

Check if ▶ ☐ Initial Return ▶ ☐ Consolidated Return (Complete Schedule M)
▶ ☐ Amended Return ☐ Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ ☐ Merged ▶ ☐ Reorganized ▶ ☐ Final

County or Counties in SC Where Property is Located:

City	Audit Location	State

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶ 435983139	▶		

PART I COMPUTATION OF INCOME TAX LIABILITY

1.	Federal Taxable Income per federal tax return	▶ 1.	-47,677,337	00
2.	Net Adjustment from line 12, Schedule A and B	2.	298,415	00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	-47,378,922	00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	NONE	00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.		00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	NONE	00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	NONE	00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.		00
9.	Balance (line 7 less line 8)	9.	NONE	00
10.	Credit Carryover (line 7, Schedule C) ▶ ____ 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.		00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	NONE	00
12.	Interest on DISC-deferred tax liability ____ 00 ; or Foreign Trade Deferred Tax Liability ____ 00	12.		00
13.	Total tax and/or interest (add lines 11 and 12)	13.	NONE	00
14.	Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ ____ 00			
	(b) Paid by Declaration ▶ ____ 00 (c) Paid with Extension ▶ ____ 00			
	(d) Credit from Line 29b ▶ ____ 00			
	Refundable Credits: (e) Ammonia Additive ▶ ____ 00			
	(f) Milk Credit ▶ ____ 00			
15	Total Payments and Refundable Credits (add lines 14a through 14f)	15.		00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	NONE	00
17.	(a) Interest Due ▶ ____ 00 (b) Late File/Pay Penalty Due ▶ ____ 00			
	(c) Declaration Penalty Due (Attach SC2220) ▶ ____ 00			
	(See penalty and interest instructions.) Enter Total.	▶ 17.		00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	NONE	00
19.	OVERPAYMENT (line 15 less line 13) ____ 00 To be applied as follows:			
	(a) Estimated Tax ▶ ____ 00 (b) License Fee ▶ ____ 00 (c) REFUNDED ▶			00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

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THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

SC 1120
(Rev. 9/2/16)
3091

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC FILE # ____

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 56-1078443

NAME CLEAN ENERGY ENTERPRISES INC
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ ☐ Address ☐ Accounting Period
☐ Officers

Attach complete copy of Federal Return
☐ Check here if you filed a federal or state extension

Check if ▶ ☐ Initial Return ▶ ☐ Consolidated Return (Complete Schedule M)
▶ ☐ Amended Return ☐ Includes Disregarded LLC(s) (Complete Schedule L)

County or Counties in SC Where Property is Located:

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ ☐ Merged ▶ ☐ Reorganized ▶ ☐ Final

City | Audit Location | State

Total Gross Receipts ▶ | Total cost of depreciable personal property in SC ▶ | Audit Contact | Telephone Number

PART I COMPUTATION OF INCOME TAX LIABILITY

1.	Federal Taxable Income per federal tax return	▶ 1.	-1,703 00
2.	Net Adjustment from line 12, Schedule A and B	2.	00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	-1,703 00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.	00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.	00
9.	Balance (line 7 less line 8)	9.	00
10.	Credit Carryover (line 7, Schedule C) ▶ ____ 00 Nonrefundable credits (line 5, Schedule C)	▶10.	(00)
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	00
12.	Interest on DISC-deferred tax liability ____ 00 ; or Foreign Trade Deferred Tax Liability ____ 00	12.	00
13.	Total tax and/or interest (add lines 11 and 12)	13.	00

14. Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s, see instructions) ▶ ____ 00
(b) Paid by Declaration ▶ ____ 00 (c) Paid with Extension ▶ ____ 00
(d) Credit from Line 29b ▶ ____ 00
Refundable Credits: (e) Ammonia Additive ▶ ____ 00
(f) Milk Credit ▶ ____ 00

15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.	00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶16.	00
17.	(a) Interest Due ▶ ____ 00 (b) Late File/Pay Penalty Due ▶ ____ 00 (c) Declaration Penalty Due (Attach SC2220) ▶ ____ 00 (See penalty and interest instructions.) Enter Total.	▶17.	00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	00

19. OVERPAYMENT (line 15 less line 13) ____ 00 To be applied as follows:
(a) Estimated Tax ▶ ____ 00 (b) License Fee ▶ ____ 00 (c) REFUNDED ▶ ____ 00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

30911036

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THO

STATE OF SOUTH CAROLINA
'C' CORPORATION INCOME TAX RETURN

Return is due on or before the 15th day of the 4th month following the close of the taxable year.

SC 1120
(Rev. 9/2/16)
3091

SC FILE # ____

INCOME TAX PERIOD ENDING 12/31/2016
LICENSE FEE PERIOD ENDING 12/31/2017
FEIN 20-0989017

NAME SCANA CORPORATE SECURITY SERVICES INC
MAILING ADDRESS 220 OPERATION WAY
CITY CAYCE STATE SC ZIP CODE 29033-3701
Change of ▶ ☐ Address ☐ Accounting Period
☐ Officers

Attach complete copy of Federal Return
☐ Check here if you filed a federal or state extension

Check if ▶ ☐ Initial Return ▶ ☐ Consolidated Return (Complete Schedule M)
▶ ☐ Amended Return ☐ Includes Disregarded LLC(s) (Complete Schedule L)

If Filing a Final Return, see General Instructions, page 6. You MUST close your account with the SECRETARY OF STATE and complete I-349.

▶ ☐ Merged ▶ ☐ Reorganized ▶ ☐ Final

County or Counties in SC Where Property is Located:

City	Audit Location	State
CAYCE		SC

Total Gross Receipts	Total cost of depreciable personal property in SC	Audit Contact	Telephone Number
▶	▶	JAMES E SWAN IV	803 217-9000

PART I COMPUTATION OF INCOME TAX LIABILITY

1.	Federal Taxable Income per federal tax return	▶ 1.	00
2.	Net Adjustment from line 12, Schedule A and B	2.	00
3.	Total Net Income as Reconciled (line 1 plus or minus line 2)	▶ 3.	00
4.	If Multi-state Corporation, enter amount from line 6, Schedule G; otherwise, enter amount from line 3.	▶ 4.	00
5.	LESS: South Carolina net operating loss carryover, if applicable	5.	00
6.	South Carolina Net Income subject to tax (line 4 less line 5)	▶ 6.	00
7.	TAX: Multiply amount on line 6 by 5% (.05)	7.	00
8.	Less tax deferred on income from foreign trade receipts (see instructions)	▶ 8.	00
9.	Balance (line 7 less line 8)	9.	00
10.	Credit Carryover (line 7, Schedule C) ▶ ____ 00 Nonrefundable credits (line 5, Schedule C)	▶ 10.	00
11.	Balance of tax (line 9 less line 10). Enter the difference but not less than zero	11.	00
12.	Interest on DISC-deferred tax liability ____ 00 ; or Foreign Trade Deferred Tax Liability ____ 00	12.	00
13.	Total tax and/or interest (add lines 11 and 12)	13.	00

14. Payments: (a) Tax Withheld (Attach 1099s, I-290s, and/or W-2s; see instructions) ▶ ____ 00
(b) Paid by Declaration ▶ ____ 00 (c) Paid with Extension ▶ ____ 00
(d) Credit from Line 29b ▶ ____ 00
Refundable Credits: (e) Ammonia Additive ▶ ____ 00
(f) Milk Credit ▶ ____ 00

15.	Total Payments and Refundable Credits (add lines 14a through 14f)	15.	00
16.	Balance of Tax and/or Interest Due (line 13 less line 15)	▶ 16.	00
17.	(a) Interest Due ▶ ____ 00 (b) Late File/Pay Penalty Due ▶ ____ 00 (c) Declaration Penalty Due (Attach SC2220) ▶ ____ 00 (See penalty and interest instructions.) Enter Total.	▶ 17.	00
18.	TOTAL INCOME TAX, Interest and Penalty Due (add lines 16 and 17) BALANCE DUE	18.	00

19. OVERPAYMENT (line 15 less line 13) ____ 00 To be applied as follows:
(a) Estimated Tax ▶ ____ 00 (b) License Fee ▶ ____ 00 (c) REFUNDED ▶ ____ 00

PART II COMPUTATION OF LICENSE FEE AND SCHEDULES A, B, AND C PAGE 2

30911036

THO 6D4936 2.000

SC1120 SCANA CORPORATION 57-0784499 Page 2

PART II COMPUTATION OF LICENSE FEE

20.	Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.	00
21.	FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22.	Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	00
23.	Balance (line 21 less line 22)	23.	00
24.	Payments: (a) Paid with Extension ▶ 00 (b) Credit from line 19b ▶ 00		
25.	Total Payments (add line 24a and 24b)	25.	00
26.	Balance of Fee Due (line 23 less line 25)	▶26.	00
27.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (See penalty and interest instructions.) Enter Total	▶27.	00
28.	TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29.	OVERPAYMENT (line 25 less line 23) 00. To be applied as follows: (a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED ▶		00
30.	GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.	00

SCHEDULE A AND B — ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1.		
2.	Federal Net Operating Loss	2.		
3.		3.		
4.		4.		
5.	Other Additions (attach schedule)	5.		
6.	Total Additions (add lines 1 through 5)		6.	

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7.	15,820	
8.		8.		
9.		9.		
10.	Other Deductions (attach schedule)	10.		
11.	Total Deductions (add lines 7 through 10)		11.	-15,820
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120		12.	-15,820

SCHEDULE C — SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2.	Enter Total Credits from SC1120-TC, Column B, line 13. **SC1120-TC must be attached to return.**	2.	
3.	Total Credits (add lines 1 and 2)	3.	
4.	Tax (line 9, Part 1, SC1120)	4.	
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer	Officer's title: CONTROLLER	Email: jswan@scana.com
Officer's printed name: JAMES E SWAN IV	Date	Telephone Number: 803-217-9000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer: Yes ☐ No ☐ Preparer's Printed Name: INTERNALLY PREPARED

Paid Preparer's Use Only

Preparer's signature	Date	Check if self-employed ☐	Preparer's Telephone Number: 8032179000
Firm's name (or yours if self-employed) and address	INTERNALLY PREPARED 220 OPERATION WAY CAYCE, SC	PTIN or FEIN ZIP Code: 29033-3701	

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature Date

30912034

THO 6D4936 2.000

SC1120 SCANA SERVICES INC 57-1092169 Page 2

PART II COMPUTATION OF LICENSE FEE

20.	Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.	00
21.	FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22.	Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	< 00 >
23.	Balance (line 21 less line 22)	23.	00
24.	Payments: (a) Paid with Extension ▶ 00 (b) Credit from line 19b ▶ 00		
25.	Total Payments (add line 24a and 24b)	25.	00
26.	Balance of Fee Due (line 23 less line 25)	▶26.	00
27.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (See penalty and interest instructions.) Enter Total	▶27.	00
28.	TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29.	OVERPAYMENT (line 25 less line 23) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED ▶		00
30.	GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.	00

SCHEDULE A AND B — ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1.	10,000	
2.	Federal Net Operating Loss	2.		
3.		3.		
4.	Amortization Adjustment	4.	2,139,118	
5.	Other Additions (attach schedule) Stmt. 9	5.	16,536,356	
6.	Total Additions (add lines 1 through 5)		6.	18,685,474

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7.		
8.		8.		
9.	Amortization Adjustment	9.	3,533,838	
10.	Other Deductions (attach schedule) Stmt. 9	10.	14,182,095	
11.	Total Deductions (add lines 7 through 10)		11.	17,715,933
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120		12.	969,541

SCHEDULE C — SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2.	Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return.	2.	20,000
3.	Total Credits (add lines 1 and 2)	3.	20,000
4.	Tax (line 9, Part 1, SC1120)	4.	572,217
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	20,000
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer	Officer's title: CONTROLLER	Email: jswan@scana.com
Officer's printed name: JAMES E SWAN IV	Date	Telephone Number: 8032179000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐

Preparer's Printed Name: INTERNALLY PREPARED

Paid Preparer's Use Only

Preparer's signature	Date	Check if self-employed ☐	Preparer's Telephone Number: 8032179000
Firm's name (or yours if self-employed) and address: INTERNALLY PREPARED, 220 OPERATION WAY, CAYCE, SC		PTIN or FEIN	ZIP Code: 29033-3701

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature Date

30912034

THO 6D4936 2.000

SC1120 SOUTH CAROLINA ELECTRIC AND GAS COMPANY 57-0248695 Page 2

PART II COMPUTATION OF LICENSE FEE

20.	Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20	00
21.	FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22.	Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	00
23.	Balance (line 21 less line 22)	23.	00
24.	Payments: (a) Paid with Extension ▶ 00 (b) Credit from line 19b ▶ 00		
25.	Total Payments (add line 24a and 24b)	25.	00
26.	Balance of Fee Due (line 23 less line 25)	▶26.	00
27.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (See penalty and interest instructions.) Enter Total	▶27.	00
28.	TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29.	OVERPAYMENT (line 25 less line 23) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED ▶		00
30.	GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.	00

SCHEDULE A AND B — ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1.		
2.	Federal Net Operating Loss	2.		
3.		3.		
4.		4.		
5.	Other Additions (attach schedule) Stmt. 10	5.	117,298,992	
6.	Total Additions (add lines 1 through 5)	6.		117,298,992

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7.		
8.		8.		
9.	Amortization Adjustment	9.	2,073,011	
10.	Other Deductions (attach schedule) Stmt. 10	10.	2,658,805	
11.	Total Deductions (add lines 7 through 10)	11.		4,731,816
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120	12.		112,567,176

SCHEDULE C — SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2.	Enter Total Credits from SC1120-TC; Column B, line 13. SC1120-TC must be attached to return.	2.	6,893,354
3.	Total Credits (add lines 1 and 2)	3.	6,893,354
4.	Tax (line 9, Part 1, SC1120)	4.	4,034,184
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	4,034,184
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	2,859,170

Please Sign Here I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer	CONTROLLER Officer's title	Email
JAMES E SWAN IV Officer's printed name	04/05/2017 Date	803-217-9000 Telephone Number

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐ Preparer's Printed Name

Paid Preparer's Use Only

Preparer's signature	Date	Check if self-employed ☐	Preparer's Telephone Number
Firm's name (or yours if self-employed) and address		PTIN or FEIN	
		ZIP Code	

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature Date

30512034

THO 6D4936 2.000

SC1120 SOUTH CAROLINA FUEL CO INC 57-0691209 Page 2

PART II COMPUTATION OF LICENSE FEE

20.	Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.	00
21.	FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22.	Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	< 00 >
23.	Balance (line 21 less line 22)	23.	00
24.	Payments: (a) Paid with Extension ▶ 00 (b) Credit from line 19b ▶ 00		
25.	Total Payments (add line 24a and 24b)	25.	00
26.	Balance of Fee Due (line 23 less line 25)	▶26.	00
27.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (See penalty and interest instructions.) Enter Total	▶27	00
28.	TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29.	OVERPAYMENT (line 25 less line 23) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED	▶	00
30.	GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.	00

SCHEDULE A AND B ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1.	
2.	Federal Net Operating Loss	2.	
3.		3.	
4.		4.	
5.	Other Additions (attach schedule)	5.	
6.	Total Additions (add lines 1 through 5)	6.	

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7.	
8.		8.	
9.		9.	
10.	Other Deductions (attach schedule)	10.	
11.	Total Deductions (add lines 7 through 10)	11.	
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120	12.	

SCHEDULE C SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2.	Enter Total Credits from SC1120-TC, Column B, line 13. **SC1120-TC must be attached to return.**	2.	
3.	Total Credits (add lines 1 and 2)	3.	
4.	Tax (line 9, Part 1, SC1120)	4.	485,997
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer	Officer's title: Controller	Email
Officer's printed name: James E Swan IV	Date	Telephone Number: 803-217-9000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐ Preparer's Printed Name

Paid Preparer's Use Only

Preparer's signature	Date	Check if self-employed ☐	Preparer's Telephone Number
Firm's name (or yours if self-employed) and address		PTIN or FEIN	
		ZIP Code	

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature Date

30912034

THO 6D4936 2.000

SC1120 SC GENERATING COMPANY INC 57-0784498 Page 2

PART II COMPUTATION OF LICENSE FEE

20.	Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.	00
21.	FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22.	Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	00
23.	Balance (line 21 less line 22)	23.	00
24.	Payments: (a) Paid with Extension ▶ 00 (b) Credit from line 19b ▶ 00		
25.	Total Payments (add line 24a and 24b)	25.	00
26.	Balance of Fee Due (line 23 less line 25)	▶26.	00
27.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (See penalty and interest instructions.) Enter Total	▶27.	00
28.	TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29.	OVERPAYMENT (line 25 less line 23) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED ▶		00
30.	GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.	00

SCHEDULE A AND B — ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1.	
2.	Federal Net Operating Loss	2.	
3.		3.	
4.		4.	
5.	Other Additions (attach schedule) Stmt. 11	5. 23,222,275	
6.	Total Additions (add lines 1 through 5)	6.	23,222,275

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7.	
8.		8.	
9.		9.	
10.	Other Deductions (attach schedule) Stmt. 11	10. 21,723,859	
11.	Total Deductions (add lines 7 through 10)	11.	21,723,859
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120	12.	1,498,416

SCHEDULE C — SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2.	Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return.	2.	1,680
3.	Total Credits (add lines 1 and 2)	3.	1,680
4.	Tax (line 9, Part 1, SC1120)	4.	552,702
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	1,680
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	

Please Sign Here — I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer | Officer's title: Controller | Email

Officer's printed name: JAMES E SWAN IV | Date | Telephone Number: (803) 217-9000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐ | Preparer's Printed Name

Paid Preparer's Use Only: Preparer's signature | Date | Check if self-employed ☐ | Preparer's Telephone Number

Firm's name (or yours if self-employed) and address | PTIN or FEIN | ZIP Code

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature | Date

30912034

THO 6D4936 2.000

SC1120 SCANA ENERGY MARKETING INC 57-0850977 Page 2

PART II COMPUTATION OF LICENSE FEE

20. Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.	00
21. FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22. Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	00
23. Balance (line 21 less line 22)	23.	00
24. Payments: (a) Paid with Extension ▶ 00		
(b) Credit from line 19b ▶ 00		
25. Total Payments (add line 24a and 24b)	25.	00
26. Balance of Fee Due (line 23 less line 25)	▶26.	00
27. (a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00		
(See penalty and interest instructions.) Enter Total	▶27.	00
28. TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29. OVERPAYMENT (line 25 less line 23) 00 To be applied as follows:		
(a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED	▶	00
30. GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT ☐	▶30.	00

SCHEDULE A AND B — ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1.	1,256,602	
2.	Federal Net Operating Loss	2.		
3.		3.		
4.	Amortization Adjustment	4.	1,098,647	
5.	Other Additions (attach schedule) Stmt. 12	5.	955,303	
6.	Total Additions (add lines 1 through 5)	6.		3,310,552

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7.		
8.		8.		
9.	Amortization Adjustment	9.	1,524,660	
10.	Other Deductions (attach schedule) Stmt. 12	10.	218,748	
11.	Total Deductions (add lines 7 through 10)	11.		1,743,408
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120	12.		1,567,144

SCHEDULE C — SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2.	Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return.	2.	
3.	Total Credits (add lines 1 and 2)	3.	
4.	Tax (line 9, Part 1, SC1120)	4.	672,952
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer — Officer's title: CONTROLLER — Email: jswan@scana.com

Officer's printed name: JAMES E SWAN IV — Date — Telephone Number: (803)2179000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer Yes ☐ No ☐ — Preparer's Printed Name

Paid Preparer's Use Only

Preparer's signature — Date — Check if self-employed ☐ — Preparer's Telephone Number

Firm's name (or yours if self-employed) and address — PTIN or FEIN — ZIP Code

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature — Date

30912034

THO 6D4836 2.000

SC1120 SERVICECARE INC 57-1007394 Page 2

PART II COMPUTATION OF LICENSE FEE

20.	Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.	00
21.	FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22.	Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	00
23.	Balance (line 21 less line 22)	23.	00
24.	Payments: (a) Paid with Extension ▶ 00		
	(b) Credit from line 19b ▶ 00		
25.	Total Payments (add line 24a and 24b)	25.	00
26.	Balance of Fee Due (line 23 less line 25)	▶26.	00
27.	(a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00		
	(See penalty and interest instructions.) Enter Total	▶27.	00
28.	TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29.	OVERPAYMENT (line 25 less line 23) 00 To be applied as follows:		
	(a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED	▶	00
30.	GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT ☐	▶30.	00

SCHEDULE A AND B — ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1.	
2.	Federal Net Operating Loss	2.	
3.		3.	
4.		4.	
5.	Other Additions (attach schedule)	5.	
6.	Total Additions (add lines 1 through 5)	6	

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7	
8.		8.	
9.		9.	
10.	Other Deductions (attach schedule)	10.	
11.	Total Deductions (add lines 7 through 10)	11.	
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120	12.	

SCHEDULE C — SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.	
2.	Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return.	2.	
3.	Total Credits (add lines 1 and 2)	3.	
4.	Tax (line 9, Part 1, SC1120)	4.	
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.	
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.	
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.	

Please Sign Here I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer — Officer's title: CONTROLLER — Email: jswan@scana.com

Officer's printed name: JAMES E SWAN IV — Date — Telephone Number: (803)2179000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐ — Preparer's Printed Name

Paid Preparer's Use Only
Preparer's signature — Date — Check if self-employed ☐ — Preparer's Telephone Number
Firm's name (or yours if self-employed) and address — PTIN or FEIN — ZIP Code

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature — Date

30912034

THO 604936 2.000

SC1120 PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483 Page 2

PART II COMPUTATION OF LICENSE FEE

20. Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E) ▶20. 00
21. FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer) ▶21. 00
22. Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C ▶22. (00)
23. Balance (line 21 less line 22) 23. 00
24. Payments: (a) Paid with Extension ▶ 00
(b) Credit from line 19b ▶ 00
25. Total Payments (add line 24a and 24b) 25. 00
26. Balance of Fee Due (line 23 less line 25) ▶26. 00
27. (a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00
(See penalty and interest instructions.) Enter Total ▶27. 00
28. TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE 28. 00
29. OVERPAYMENT (line 25 less line 23) 00 To be applied as follows:
(a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED ▶ 00
30. GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 16 and 28) EFT ▶30. 00

SCHEDULE A AND B ADDITIONS TO FEDERAL TAXABLE INCOME

1.	Taxes on or Measured By Income	1. 298,415	
2.	Federal Net Operating Loss	2.	
3.		3.	
4.		4.	
5.	Other Additions (attach schedule)	5.	
6.	Total Additions (add lines 1 through 5)		6. 298,415

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7.	Interest On Obligations Of The U.S.	7.	
8.		8.	
9.		9.	
10.	Other Deductions (attach schedule)	10.	
11.	Total Deductions (add lines 7 through 10)		11.
12.	Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120		12. 298,415

SCHEDULE C SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1.	Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13)	1.
2.	Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return.	2.
3.	Total Credits (add lines 1 and 2)	3.
4.	Tax (line 9, Part 1, SC1120)	4. NONE
5.	Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.)	5.
6.	Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.)	6.
7.	Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.)	7.

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer | Controller Officer's title | Email

James E Swan IV
Officer's printed name | Date | Telephone Number

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐ | Preparer's Printed Name

Paid Preparer's Use Only

Preparer's signature | Date | Check if self-employed ☐ | Preparer's Telephone Number

Firm's name (or yours if self-employed) and address | PTIN or FEIN | ZIP Code

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature | Date

30912034

THO 5D4936 2.000

SC1120 CLEAN ENERGY ENTERPRISES INC 56-1078443 Page 2

PART II COMPUTATION OF LICENSE FEE

20. Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.	00
21. FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.	00
22. Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.	00
23. Balance (line 21 less line 22)	23.	00
24. Payments: (a) Paid with Extension ▶ 00		
(b) Credit from line 19b ▶ 00		
25. Total Payments (add line 24a and 24b)	25.	00
26. Balance of Fee Due (line 23 less line 25)	▶26.	00
27. (a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00 (See penalty and interest instructions.) Enter Total	▶27.	00
28. TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.	00
29. OVERPAYMENT (line 25 less line 23) 00 To be applied as follows: (a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED	▶	00
30. GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.	00

SCHEDULE A AND B — ADDITIONS TO FEDERAL TAXABLE INCOME

1. Taxes on or Measured By Income 1. ____
2. Federal Net Operating Loss 2. ____
3. ____ 3. ____
4. ____ 4. ____
5. Other Additions (attach schedule) 5. ____
6. Total Additions (add lines 1 through 5) 6. ____

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7. Interest On Obligations Of The U.S. 7. ____
8. ____ 8. ____
9. ____ 9. ____
10. Other Deductions (attach schedule) 10. ____
11. Total Deductions (add lines 7 through 10) 11. ____
12. Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120 12. ____

SCHEDULE C — SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1. Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13) 1. ____
2. Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return. 2. ____
3. Total Credits (add lines 1 and 2) 3. ____
4. Tax (line 9, Part 1, SC1120) 4. ____
5. Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.) 5. ____
6. Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.) 6. ____
7. Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.) 7. ____

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer ____ Officer's title: CONTROLLER Email: JSWAN@SCANA.COM

Officer's printed name: JAMES E SWAN IV Date ____ Telephone Number: 803-217-9000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐ Preparer's Printed Name

Paid Preparer's Use Only

Preparer's signature ____ Date ____ Check if self-employed ☐ Preparer's Telephone Number

Firm's name (or yours if self-employed) and address ____ PTIN or FEIN ____ ZIP Code ____

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349.

Taxpayer's Signature ____ Date ____

30912034

THO 6D4936 2.000

SC1120 SCANA CORPORATE SECURITY SERVICES INC 20-0989017 Page 2

PART II COMPUTATION OF LICENSE FEE

20. Total Capital And Paid in Surplus (Multi-State Corporations See Schedule E)	▶20.		00
21. FEE DUE - Line 20 x .001, plus $15.00 (Fee cannot be less than $25.00 per taxpayer)	▶21.		00
22. Credit Carryover ▶ 00 Credit taken this year from SC1120TC, Part II, Column C	▶22.		00
23. Balance (line 21 less line 22)	23.		00
24. Payments: (a) Paid with Extension ▶ 00			
(b) Credit from line 19b ▶ 00			
25. Total Payments (add line 24a and 24b)	25.		00
26. Balance of Fee Due (line 23 less line 25)	▶26.		00
27. (a) Interest Due ▶ 00 (b) Late File/Pay Penalty Due ▶ 00			
(See penalty and interest instructions) Enter Total	▶27.		00
28. TOTAL LICENSE FEE, Interest and Penalty Due (add lines 26 and 27) BALANCE DUE	28.		00
29. OVERPAYMENT (line 25 less line 23) 00 To be applied as follows:			
(a) Estimated Tax ▶ 00 (b) Income Tax ▶ 00 (c) REFUNDED	▶		00
30. GRAND TOTAL: INCOME TAX and LICENSE FEE DUE (add lines 18 and 28) EFT	▶30.		00

SCHEDULE A AND B ADDITIONS TO FEDERAL TAXABLE INCOME

1. Taxes on or Measured By Income 1.
2. Federal Net Operating Loss 2.
3. 3.
4. 4.
5. Other Additions (attach schedule) 5.
6. Total Additions (add lines 1 through 5) 6.

DEDUCTIONS FROM FEDERAL TAXABLE INCOME

7. Interest On Obligations Of The U.S. 7.
8. 8.
9. 9.
10. Other Deductions (attach schedule) 10.
11. Total Deductions (add lines 7 through 10) 11.
12. Net Adjustment (line 6 less line 11) Also enter on line 2, Part 1, SC1120 12.

SCHEDULE C SUMMARY OF INCOME TAX CREDITS (FROM SC1120-TC)

1. Credit Carryover From Previous Year's SC1120, Schedule C (NOTE: Should agree to SC1120-TC Column A, line 13) 1.
2. Enter Total Credits from SC1120-TC, Column B, line 13. SC1120-TC must be attached to return. 2.
3. Total Credits (add lines 1 and 2) 3.
4. Tax (line 9, Part 1, SC1120) 4.
5. Lesser of line 3 or 4 (enter on line 10, Part 1, SC1120) (NOTE: Should agree to SC1120-TC, Column C, line 13.) 5.
6. Enter Credits Lost Due to Statute (NOTE: Should agree to SC1120-TC, Column D, line 13.) 6.
7. Credit Carryover (line 3 less lines 5 and 6) (NOTE: Should agree to SC1120-TC, Column E, line 13.) 7.

Please Sign Here

I, the undersigned, a principal officer of the corporation for which this return is made declare that this return, including accompanying Annual Report, statements and schedules, has been examined by me and is to the best of my knowledge and belief, a true and complete return.

Signature of officer — Officer's title: CONTROLLER — Email

Officer's printed name: JAMES E SWAN IV — Date — Telephone Number: 803 217-9000

I authorize the Director of the Department of Revenue or delegate to discuss this return, attachments and related tax matters with the preparer. Yes ☐ No ☐

Preparer's Printed Name: INTERNALLY PREPARED

Paid Preparer's Use Only

Preparer's signature — Date — Check if self-employed ☐ — Preparer's Telephone Number: 8032179000

Firm's name (or yours if self-employed) and address: INTERNALLY PREPARED, 220 OPERATION WAY, CAYCE, SC — PTIN or FEIN — ZIP Code: 29033-3701

If this is a corporation's final return, signing here authorizes the Department of Revenue to disclose that information with the Secretary of State. You must close with the Secretary of State as well as the Department of Revenue and complete I-349

Taxpayer's Signature — Date

30912034

THO 6D4955 1.000

SC1120 Page 3

SCHEDULE D ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS

1. Name SCANA CORPORATION
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
   In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 13
   Nature of principal business in SC HOLDING COMPANY
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: 200,000,000. CLASS: COMMON SERIES SCG1
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: 142,916,917. CLASS: COMMON SERIES SCG1
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are:
   (If additional space is necessary, attach separate schedule).
   NAME TITLE BUSINESS ADDRESS
   SEE ATTACHED LIST OF OFFICERS FOR ALL SUBSIDIARIES
8. Date Incorporated 10/01/1984 Date commenced business in the State of South Carolina was 10/01/1984
9. Date of this report 09/15/2017 FEIN 57-0784499
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 10/01/1984
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 13
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 2,341,403,986
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 2,341,403,986

ATTACH COMPLETE COPY OF FEDERAL RETURN

Payment Only: Submit payment electronically for free at MyDORWAY.dor.sc.gov.

MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:	REFUNDS OR ZERO TAX:
SCDOR	SCDOR
CORPORATE TAXABLE	CORPORATE REFUND
COLUMBIA, SC 29214-0033	COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1.000

SC1120 SCANA SERVICES INC 57-1092169 Page 3

SCHEDULE D ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of ______
3. Location of the Registered Office of the Corporation in the State of South Carolina is ______
   In the City of ______ Registered Agent at such address is ______
4. Location of principal office (street address) ______
   Nature of principal business in SC ______
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are:
   (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ______ Date commenced business in the State of South Carolina was ______
9. Date of this report ______ FEIN ______
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is ______
11. Was the name of the Corporation changed during the year? ______ Give old name ______
12. The Corporation's books are in the care of ______
    Located at (street address) ______
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ ______
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ ______
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ ______

ATTACH COMPLETE COPY OF FEDERAL RETURN

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MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:	REFUNDS OR ZERO TAX:
SCDOR	SCDOR
CORPORATE TAXABLE	CORPORATE REFUND
COLUMBIA, SC 29214-0033	COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1.000

SC1120 SOUTH CAROLINA ELECTRIC AND GAS COMPANY 57-0248695 Page 3

SCHEDULE D **ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS**

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of ______
3. Location of the Registered Office of the Corporation in the State of South Carolina is ______
   In the City of ______ Registered Agent at such address is ______
4. Location of principal office (street address) ______
   Nature of principal business in SC ______
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ______ Date commenced business in the State of South Carolina was ______
9. Date of this report ______ FEIN ______
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is ______
11. Was the name of the Corporation changed during the year? ______ Give old name ______
12. The Corporation's books are in the care of ______
    Located at (street address) ______
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ ______
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ ______
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ ______

ATTACH COMPLETE COPY OF FEDERAL RETURN

Payment Only: Submit payment electronically for free at MyDORWAY.dor.sc.gov.

MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:
SCDOR
CORPORATE TAXABLE
COLUMBIA, SC 29214-0033

REFUNDS OR ZERO TAX:
SCDOR
CORPORATE REFUND
COLUMBIA, SC 29214-0032

30913032

THO 604955 1:000

SC1120 SOUTH CAROLINA FUEL CO INC 57-0691209 Page 3

SCHEDULE D **ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS**

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of
3. Location of the Registered Office of the Corporation in the State of South Carolina is
   In the City of _____ Registered Agent at such address is
4. Location of principal office (street address)
   Nature of principal business in SC
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: _____ CLASS: _____ SERIES:
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: _____ CLASS: _____ SERIES:
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated _____ Date commenced business in the State of South Carolina was
9. Date of this report _____ FEIN
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is
11. Was the name of the Corporation changed during the year? _____ Give old name
12. The Corporation's books are in the care of
    Located at (street address)
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $

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MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:
SCDOR
CORPORATE TAXABLE
COLUMBIA, SC 29214-0033

REFUNDS OR ZERO TAX:
SCDOR
CORPORATE REFUND
COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1.000

SC1120 SC GENERATING COMPANY INC 57-0784498 Page 3

SCHEDULE D ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of
3. Location of the Registered Office of the Corporation in the State of South Carolina is
In the City of ______ Registered Agent at such address is
4. Location of principal office (street address)
Nature of principal business in SC
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ______ Date commenced business in the State of South Carolina was ______
9. Date of this report ______ FEIN ______
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is ______
11. Was the name of the Corporation changed during the year? ______ Give old name ______
12. The Corporation's books are in the care of ______
Located at (street address) ______
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ ______
B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ ______
C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ ______

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MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:
SCDOR
CORPORATE TAXABLE
COLUMBIA, SC 29214-0033

REFUNDS OR ZERO TAX:
SCDOR
CORPORATE REFUND
COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1 000

SC1120 SCANA ENERGY MARKETING INC 57-0850977 Page 3

SCHEDULE D **ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS**

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of
3. Location of the Registered Office of the Corporation in the State of South Carolina is
   In the City of ____ Registered Agent at such address is
4. Location of principal office (street address)
   Nature of principal business in SC
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ____ CLASS: ____ SERIES: ____
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ____ CLASS: ____ SERIES: ____
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are:
   (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ____ Date commenced business in the State of South Carolina was
9. Date of this report ____ FEIN
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is
11. Was the name of the Corporation changed during the year? ____ Give old name
12. The Corporation's books are in the care of
    Located at (street address)
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . . $

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MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:
SCDOR
CORPORATE TAXABLE
COLUMBIA, SC 29214-0033

REFUNDS OR ZERO TAX:
SCDOR
CORPORATE REFUND
COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1.000

SC1120 SERVICECARE INC 57-1007394 Page 3

SCHEDULE D **ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS**

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of ____
3. Location of the Registered Office of the Corporation in the State of South Carolina is ____
   In the City of ____ Registered Agent at such address is ____
4. Location of principal office (street address) ____
   Nature of principal business in SC ____
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ____ CLASS: ____ SERIES: ____
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ____ CLASS: ____ SERIES: ____
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ____ Date commenced business in the State of South Carolina was ____
9. Date of this report ____ FEIN ____
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is ____
11. Was the name of the Corporation changed during the year? ____ Give old name ____
12. The Corporation's books are in the care of ____
    Located at (street address) ____
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ ____
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ ____
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ ____

ATTACH COMPLETE COPY OF FEDERAL RETURN

Payment Only: Submit payment electronically for free at MyDORWAY.dor.sc.gov.

MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:	REFUNDS OR ZERO TAX:
SCDOR	SCDOR
CORPORATE TAXABLE	CORPORATE REFUND
COLUMBIA, SC 29214-0033	COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1.000

SC1120 PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483 Page 3

SCHEDULE D **ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS**

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of ______
3. Location of the Registered Office of the Corporation in the State of South Carolina is ______
   in the City of ______ Registered Agent at such address is ______
4. Location of principal office (street address) ______
   Nature of principal business in SC ______
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are:
   (If additional space is necessary, attach separate schedule)

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ______ Date commenced business in the State of South Carolina was ______
9. Date of this report ______ FEIN ______
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is ______
11. Was the name of the Corporation changed during the year? ______ Give old name ______
12. The Corporation's books are in the care of ______
    Located at (street address) ______
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ ______
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ ______
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ ______

ATTACH COMPLETE COPY OF FEDERAL RETURN

Payment Only: Submit payment electronically for free at MyDORWAY.dor.sc.gov.

MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:
SCDOR
CORPORATE TAXABLE
COLUMBIA, SC 29214-0033

REFUNDS OR ZERO TAX:
SCDOR
CORPORATE REFUND
COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1.000

SC1120 CLEAN ENERGY ENTERPRISES INC 56-1078443 Page 3

SCHEDULE D **ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS**

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of
3. Location of the Registered Office of the Corporation in the State of South Carolina is
   In the City of ____ Registered Agent at such address is
4. Location of principal office (street address)
   Nature of principal business in SC
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ____ CLASS: ____ SERIES: ____
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ____ CLASS: ____ SERIES: ____
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ____ Date commenced business in the State of South Carolina was
9. Date of this report ____ FEIN
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is
11. Was the name of the Corporation changed during the year? ____ Give old name
12. The Corporation's books are in the care of
    Located at (street address)
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $

ATTACH COMPLETE COPY OF FEDERAL RETURN

Payment Only: Submit payment electronically for free at MyDORWAY.dor.sc.gov.

MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:	REFUNDS OR ZERO TAX:
SCDOR	SCDOR
CORPORATE TAXABLE	CORPORATE REFUND
COLUMBIA, SC 29214-0033	COLUMBIA, SC 29214-0032

30913032

THO 6D4955 1.000

SC1120 SCANA CORPORATE SECURITY SERVICES INC 20-0989017 Page 3

SCHEDULE D **ANNUAL REPORT TO BE COMPLETED BY ALL CORPORATIONS**

1. Name THIS SCHEDULE DOES NOT PRINT FOR SUBS
2. Incorporated under the laws of the State of
3. Location of the Registered Office of the Corporation in the State of South Carolina is
   In the City of ______ Registered Agent at such address is
4. Location of principal office (street address)
   Nature of principal business in SC
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:
   NUMBER OF SHARES: ______ CLASS: ______ SERIES: ______
7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated ______ Date commenced business in the State of South Carolina was
9. Date of this report ______ FEIN
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is
11. Was the name of the Corporation changed during the year? ______ Give old name
12. The Corporation's books are in the care of
    Located at (street address)
13. If filing consolidated, complete and attach Schedule J for each Corporation included in the consolidation.
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $

ATTACH COMPLETE COPY OF FEDERAL RETURN

Payment Only: Submit payment electronically for free at MyDORWAY.dor.sc.gov.

MAIL RETURN TO THE PROPER ADDRESS

BALANCE DUE:
SCDOR
CORPORATE TAXABLE
COLUMBIA, SC 29214-0033

REFUNDS OR ZERO TAX:
SCDOR
CORPORATE REFUND
COLUMBIA, SC 29214-0032

30913032

THO

6D4937 1.000

SC1120 SCANA CORPORATION 57-0784499 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref.. for. Page. 1,. Line. 21 $
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . . $

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1	1.	-66,004,319
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	-66,004,319
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	-66,004,319
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	-66,004,319

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)	8,540,738	
2. Total Sales Everywhere (see instructions)	8,540,738	
3. Sales Ratio (line 1 ÷ line 2)		100.0000 %

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 – line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 – line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

THO 6D4937 1.000

SC1120. SCANA SERVICES INC 57-1092169 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref.. for. Page. 1,. Line. 21 $
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . . $

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled Enter amount from line 3, Page 1	1.	11,655,246
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	11,655,246
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	11,444,344
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	11,444,344

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)	407,686,970	
2. Total Sales Everywhere (see instructions)	415,200,018	
3. Sales Ratio (line 1 ÷ line 2)		98.1905 %

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 – line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 – line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

-30914030

6D4937 1.000

THO

SC1120 SOUTH CAROLINA ELECTRIC AND GAS COMPANY 57-0248695 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E — COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref.. for. Page. 1,. Line. 21 $
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . . $

SCHEDULE F — INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G — COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1	1.	82,830,564
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	82,830,564
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	80,683,679
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	80,683,679

SCHEDULE H-1 — COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)	2,936,913,834	
2. Total Sales Everywhere (see instructions)	3,015,062,429	
3. Sales Ratio (line 1 ÷ line 2)		97.4081 %

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 — COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 - line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 - line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 — COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

THO

6D4937 1.000

SC1120 SOUTH CAROLINA FUEL CO INC 57-0691209 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref. for Page. 1, Line 21 $ ______
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . $ ______

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1	1.	9,719,948
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	9,719,948
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	9,719,948
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	9,719,948

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)	237,225,342	
2. Total Sales Everywhere (see instructions)	237,225,342	
3. Sales Ratio (line 1 ÷ line 2)		100.0000 %

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 - line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 - line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

THO

6D4937 1.000

SC1120 SC GENERATING COMPANY INC 57-0784498 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref. for Page. 1. Line. 21 $
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate) Also enter on line 20, Part II . . . . $

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1	1.	11,054,044
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	11,054,044
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	11,054,044
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	11,054,044

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)	193,888,768	
2. Total Sales Everywhere (see instructions)	193,888,768	
3. Sales Ratio (line 1 ÷ line 2)		100.0000 %

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 – line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 – line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

THO 6D4937 1.000

SC1120 SCANA ENERGY MARKETING INC 57-0850977 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref. for Page. 1, Line. 21 $
2. SC PROPORTION. (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . . $

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1	1.	49,754,299
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	49,754,299
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	13,459,035
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	13,459,035

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)	253,918,032	
2. Total Sales Everywhere (see instructions)	938,663,472	
3. Sales Ratio (line 1 ÷ line 2)		27.0510 %

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 - line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 - line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

THO

6D4937 1.000

SC1120 SERVICECARE INC 57-1007394 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref.. for. Page. 1, Line. 21 $
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . . $

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1	1.	-1,192,180
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	-1,192,180
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	-1,192,180
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	-1,192,180

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)	5,863	
2. Total Sales Everywhere (see instructions)	5,863	
3. Sales Ratio (line 1 ÷ line 2)		100.0000 %

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 – line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 – line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

604937 1.000

THO

SC1120 PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref.. for. Page. 1,. Line. 21 $
2. SC PROPORTION. (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . . $

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1	1.	-47,378,922
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7	2.	
3. Total net income subject to apportionment (line 1 less line 2)	3.	-47,378,922
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here	4.	NONE
5. Add: Income subject to direct allocation to SC from Schedule F, line 8	5.	
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1	6.	NONE

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)		
2. Total Sales Everywhere (see instructions)		
3. Sales Ratio (line 1 ÷ line 2)		NONE%

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 - line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 - line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

THO 6D4837 1.000

SC1120 CLEAN ENERGY ENTERPRISES INC 56-1078443 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref.. for. Page. 1,. Line. 21 $
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate). Also enter on line 20, Part II . . . . $

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1 . . . . 1.
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7 . . . . 2.
3. Total net income subject to apportionment (line 1 less line 2) . . . . 3.
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here . . . . 4.
5. Add: Income subject to direct allocation to SC from Schedule F, line 8 . . . . 5.
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1 . . . . 6.

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)		
2. Total Sales Everywhere (see instructions)		
3. Sales Ratio (line 1 ÷ line 2)		%

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 – line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 – line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

6D4937 1.000

THO

SC1120 SCANA CORPORATE SECURITY SERVICES INC 20-0989017 Page 4

ONLY MULTI-STATE CORPORATIONS MUST COMPLETE SCHEDULES E, F, G, AND H

SCHEDULE E COMPUTATION OF LICENSE FEE OF MULTI-STATE CORPORATIONS

1. Total Capital and Paid-in-Surplus at end of Year See. Stmt. Ref. for Page. 1, Line. 21 $ ______
2. SC PROPORTION: (line 1 X ratio from Schedule H-1, H-2 or H-3, as appropriate) Also enter on line 20, Part II . . . . $ ______

SCHEDULE F INCOME SUBJECT TO DIRECT ALLOCATION

	Gross Amounts 1	Less: Related Expenses 2	Net Amounts Allocated Directly to SC and Other States 3	Net Amounts Allocated Directly to SC 4
1. Interest not connected with business				
2. Dividends received				
3. Rents				
4. Gains/losses on real property				
5. Gains/losses on intangible pers. prop.				
6. Investment income directly allocated				
7. TOTAL INCOME DIRECTLY ALLOCATED				
8. INCOME DIRECTLY ALLOCATED TO SC				

SCHEDULE G COMPUTATION OF TAXABLE INCOME OF MULTI-STATE CORPORATIONS

1. Total net income as reconciled. Enter amount from line 3, Page 1 . . . . . 1. ______
2. Less: Income subject to direct allocation to SC and other states from Schedule F, line 7 . . . . . 2. ______
3. Total net income subject to apportionment (line 1 less line 2) . . . . . 3. ______
4. Multiply amount on line 3 by appropriate ratio from Schedule H-1, H-2, or H-3 and enter result here . . . . . 4. ______
5. Add: Income subject to direct allocation to SC from Schedule F, line 8 . . . . . 5. ______
6. Total SC Net Income (sum of lines 4 and 5 above) also enter on line 4, Part 1 of Page 1 . . . . . 6. ______

SCHEDULE H-1 COMPUTATION OF SALES RATIO

	Amount	Ratio
1. Total Sales Within South Carolina (see instructions)		
2. Total Sales Everywhere (see instructions)		
3. Sales Ratio (line 1 ÷ line 2)		%

Note: If there are no sales anywhere: Enter 100% on Line 3, if South Carolina is the principal place of business OR
Enter 0% on Line 3, if principal place of business is outside South Carolina.

SCHEDULE H-2 COMPUTATION OF GROSS RECEIPTS RATIO

	Amount	Ratio
1. South Carolina Gross Receipts		
2. Amounts Allocated to South Carolina on Schedule F	< >	
3. South Carolina Adjusted Gross Receipts (line 1 - line 2)		
4. Total Gross Receipts		
5. Total Amounts Allocated on Schedule F	< >	
6. Total Adjusted Gross Receipts (line 4 - line 5)		
7. Gross Receipts Ratio (line 3 ÷ line 6)		%

SCHEDULE H-3 COMPUTATION OF RATIO FOR SECTION 12-6-2310 COMPANIES

	Amount	Ratio
1. Total Within South Carolina (see instructions)		
2. Total Everywhere		
3. Taxable Ratio (line 1 ÷ line 2)		%

30914030

THO 6D4939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 1

1. Name SCANA CORPORATION
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
   In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 14
   Nature of principal business in S.C. HOLDING COMPANY
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
200,000,000.	COMMON	SCG1

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
142,916,917.	COMMON	SCG1

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated 10/01/1984 Date commenced business in the State of South Carolina was 10/01/1984
9. Date of this report 09/15/2017 FEIN 57-0784499 SC File # 20119164
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 10/01/1984
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 14
13. Corporate Mailing Address 220 OPERATION WAY CAYCE
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 2,341,403,986.
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ -76,171,514.
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 2,265,232,472.

For additional affiliated corporations, include additional Schedule Js as needed.

30915037

THO 6D4939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 2

1. Name SCANA SERVICES INC
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
   In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 15
   Nature of principal business in S.C. SERVICES FOR CONSOLIDATED GROUP
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1,000.	COMMON	NA

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1,000.	COMMON	NA

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS
KEVIN B MARSH	President	220 OPERATION WAY CAYCE SC, 29033
JIMMY E ADDISON	Vice President	220 OPERATION WAY CAYCE SC, 29033
GINA S CHAMPION	Secretary	220 OPERATION WAY CAYCE SC, 29033
IRIS GRIFFIN	Treasurer	220 OPERATION WAY CAYCE SC, 29033

8. Date Incorporated 12/15/1999 Date commenced business in the State of South Carolina was 12/15/1999
9. Date of this report 09/15/2017 FEIN 57-1092169 SC File # 20119164
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 12/15/1999
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 15
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 1,000.
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ 6,849,916.
    C Total amount of stated Capital (cannot be a negative amount) . . . . . $ 6,850,916.

For additional affiliated corporations, include additional Schedule Js as needed.

30915037

THO

6D4939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 3

1. Name SOUTH CAROLINA ELECTRIC AND GAS COMPANY
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET in the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 16
   Nature of principal business in S.C. PUBLIC UTILITY
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
50,000,000.	COMMON	NA

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
40,296,147.	COMMON	NA

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS
	See Statement 16	

8. Date Incorporated 07/19/1924 Date commenced business in the State of South Carolina was 07/19/1924
9. Date of this report 09/15/2017 FEIN 57-0248695 SC File #
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 16
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . . . $ 576,505,122.
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ 2,283,832,337.
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 2,860,337,459.

For additional affiliated corporations, include additional Schedule Js as needed.

30915037

THO 604939 1.000

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SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 4

1. Name SOUTH CAROLINA FUEL CO INC
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 Laurel Street
   In the City of Columbia Registered Agent at such address is Corporation Service Company
4. Location of principal office (street address) See Statement 17
   Nature of principal business in S.C. Acquire Fuel
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1. N/A	Common	

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1. N/A	Common	

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated 09/28/1979 Date commenced business in the State of South Carolina was 09/28/1979
9. Date of this report 09/15/2017 FEIN 57-0691209 SC File #
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of James E Swan IV
    Located at (street address) See Statement 17
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 1,000.
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ 2,695,226.
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 2,696,226.

For additional affiliated corporations, include additional Schedule Js as needed.

30915037

THO 604939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 5

1. Name SC GENERATING COMPANY INC
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
   In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 18
   Nature of principal business in S.C. PUBLIC UTILITY
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
10,000. NA		COMMON

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
10,000. NA		COMMON

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated 10/01/1984 Date commenced business in the State of South Carolina was 10/01/1984
9. Date of this report 09/15/2017 FEIN 57-0784498 SC File #
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 18
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 20,000,000.
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ 32,307,572.
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 52,307,572.

For additional affiliated corporations, include additional Schedule Js as needed.

30915037

THO

6D4939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 6

1. Name SCANA ENERGY MARKETING INC
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
   In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 19
   Nature of principal business in S.C. MARKETING NATURAL GAS
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1,000.	COMMON	NA

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1.	COMMON	NA

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS
KEVIN B MARSH	Other	220 OPERATION WAY CAYCE SC, 29033
JIMMY E ADDISON	Other	220 OPERATION WAY CAYCE SC, 29033
SARENA D BURCH	Other	220 OPERATION WAY CAYCE SC, 29033
RONALD T LINDSAY	Other	220 OPERATION WAY CAYCE SC, 29033

8. Date Incorporated 08/22/1977 Date commenced business in the State of South Carolina was 08/22/1977
9. Date of this report 09/15/2017 FEIN 57-0850977 SC File # 20119164
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 08/22/1977
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 19
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 1,000.
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ 44,670,574.
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 44,671,574.

For additional affiliated corporations, include additional Schedule Js as needed.

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THO 6D4939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 7

1. Name SERVICECARE INC
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
   In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 20
   Nature of principal business in S.C. SERVICE CONTRACTS FOR APPLIANCES
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS
D RUSSELL HARRIS	President	220 OPERATION WAY CAYCE SC, 29033
JIMMY E ADDISON	Vice President	220 OPERATION WAY CAYCE SC, 29033
GINA S CHAMPION	Secretary	220 OPERATION WAY CAYCE SC, 29033
IRIS GRIFFIN	Treasurer	220 OPERATION WAY CAYCE SC, 29033

8. Date Incorporated 09/20/1994 Date commenced business in the State of South Carolina was 09/20/1994
9. Date of this report 09/15/2017 FEIN 57-1007394 SC File #
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 09201994
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 20
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $

For additional affiliated corporations, include additional Schedule Js as needed.

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6D4939 1.000

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SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 8

1. Name PUBLIC SERVICE COMPANY OF NORTH CAROLINA
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
   In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 21
   Nature of principal business in S.C. NONE
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1,000.	COMMON	NA

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1.	COMMON	NA

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated 02/12/1999 Date commenced business in the State of South Carolina was 02/11/2000
9. Date of this report 09/15/2017 FEIN 56-2128483 SC File #
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 02/11/2000
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
    Located at (street address) See Statement 21
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
    A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ -3,000.
    B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ 633,191,818.
    C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 633,188,818.

For additional affiliated corporations, include additional Schedule Js as needed.

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6D4939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN

AFFILIATED CORPORATION NO. 9

1. Name CLEAN ENERGY ENTERPRISES INC
2. Incorporated under the laws of the State of NC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
In the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address)
Nature of principal business in S.C. SALE OF NATURAL GAS VEHICLE PRODUCTS & SERVICE
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
2,000.	COMMON	NA

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
2,000.	COMMON	NA

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are: (If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS

8. Date Incorporated 08/12/1974 Date commenced business in the State of South Carolina was 02/01/1994
9. Date of this report 09/15/2017 FEIN 56-1078443 SC File #
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 02/15/1994
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
Located at (street address) See Statement 22
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 2,000.
B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $ 438.
C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 2,438.

For additional affiliated corporations, include additional Schedule Js as needed.

THO 6D4939 1.000

SC1120 Page 5

SCHEDULE I RESERVED

SCHEDULE J CORPORATIONS INCLUDED IN CONSOLIDATED RETURN
AFFILIATED CORPORATION NO. 10

1. Name SCANA CORPORATE SECURITY SERVICES INC
2. Incorporated under the laws of the State of SC
3. Location of the Registered Office of the Corporation in the State of South Carolina is 1703 LAUREL STREET
in the City of COLUMBIA Registered Agent at such address is CORPORATION SERVICE COMPANY
4. Location of principal office (street address) See Statement 23
Nature of principal business in S.C. SECURITY SERVICES
5. The total number of authorized shares of capital stock, itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1,000.	COMMON	NA

6. The total number of issued and outstanding shares of capital stock itemized by class and series, if any, within each class is as follows:

NUMBER OF SHARES	CLASS	SERIES
1,000.	COMMON	NA

7. The names and business addresses of the directors (or individuals functioning as directors) and principal officers in the Corporation are:
(If additional space is necessary, attach separate schedule).

NAME	TITLE	BUSINESS ADDRESS
RANDAL M SENN	President	220 OPERATION WAY CAYCE SC, 29033
JIMMY E ADDISON	Vice President	220 OPERATION WAY CAYCE SC, 29033
GINA S CHAMPION	Secretary	220 OPERATION WAY CAYCE SC, 29033
IRIS GRIFFIN	Treasurer	220 OPERATION WAY CAYCE SC, 29033

8. Date Incorporated 03/19/2004 Date commenced business in the State of South Carolina was 03/19/2004
9. Date of this report 09/15/2017 FEIN 20-0989017 SC File #
10. If Foreign Corporation, the date qualified to do business in the State of South Carolina is 03/19/2004
11. Was the name of the Corporation changed during the year? NO Give old name
12. The Corporation's books are in the care of JAMES E SWAN IV
Located at (street address) See Statement 23
13. Corporate Mailing Address 220 OPERATION WAY
14. The total amount of stated capital per balance sheet is:
A. Total paid in Capital Stock (cannot be a negative amount) . . . . $ 1,000.
B. Total paid in Capital Surplus (cannot be a negative amount) . . . . . . $
C. Total amount of stated Capital (cannot be a negative amount) . . . . . $ 1,000.

For additional affiliated corporations, include additional Schedule Js as needed.

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SCHEDULE M CONSOLIDATED RETURN AFFILIATIONS SCHEDULE

Include additional Schedule Ms as needed. Include only corporations doing business in SC.

Part 1 General Information

Is the Common Parent Corporation included in the return?

Yes [X] No [ ]

If NO, enter Name and Federal Employer Identification Number (FEIN) of Common Parent Corporation.

SCANA CORPORATION — 57-0784499
NAME OF COMMON PARENT CORPORATION — FEIN

	Name of Each Corporation Included in This Consolidated Return	FEIN
Corporation 1	SCANA CORPORATION	57-0784499
Corporation 2	SCANA SERVICES INC	57-1092169
Corporation 3	SOUTH CAROLINA ELECTRIC AND GAS COMPANY	57-0248695
Corporation 4	SOUTH CAROLINA FUEL CO INC	57-0691209
Corporation 5	SC GENERATING COMPANY INC	57-0784498
Corporation 6	SCANA ENERGY MARKETING INC	57-0850977
Corporation 7	SERVICECARE INC	57-1007394
Corporation 8	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	56-2128483

Part 2 Income Tax Information

	Federal Taxable Income	Amounts Directly Allocated	Amounts Allocated to SC	SC Adjustments	SC NOL Prior Year Carryovers
Corporation 1	$ -65,988,499	$	$	$ -15,820	$
Corporation 2	10,685,705			969,541	
Corporation 3	-29,736,612			112,567,176	
Corporation 4	9,719,948			NONE	
Corporation 5	9,555,628			1,498,416	
Corporation 6	48,187,155			1,567,144	
Corporation 7	-1,192,180				
Corporation 8	-47,677,337			298,415	
Total	-66,447,895			116,884,872	
	Equals page 1, line 1	Equals Sch. F, line 7	Equals Sch. F, line 8	Equals page 1, line 2	Equals page 1, line 5

Part 3 License Fee, Allocation, and Apportionment Information

	Tax Credited on Return	Total Capital and Paid in Surplus	Apportionment Percentage	License Fee
Corporation 1	$	$ 2,341,403,986	100.0000%	$ 2,341,419
Corporation 2		6,726,949	98.1905	6,742
Corporation 3		2,786,200,372	97.4081	14,284,476
Corporation 4		2,696,226	100.0000	2,711
Corporation 5		52,307,572	100.0000	163,211
Corporation 6		12,084,107	27.0510	12,099
Corporation 7			100.0000	25
Corporation 8		633,188,818	NONE	25
Total		5,834,611,468		16,810,758
	Equals page 1, line 15	Equals page 2, line 20	Per Schedule H	Equals page 2, line 21

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6D4946 1.000

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SCHEDULE M CONSOLIDATED RETURN AFFILIATIONS SCHEDULE

Include additional Schedule Ms as needed. Include only corporations doing business in SC.

Part 1 General Information

Is the Common Parent Corporation included in the return?

Yes ☐ No ☐

If NO, enter Name and Federal Employer Identification Number (FEIN) of Common Parent Corporation.

NAME OF COMMON PARENT CORPORATION | FEIN

	Name of Each Corporation Included in This Consolidated Return	FEIN
Corporation 1	CLEAN ENERGY ENTERPRISES INC	56-1078443
Corporation 2	SCANA CORPORATE SECURITY SERVICES INC	20-0989017
Corporation 3		
Corporation 4		
Corporation 5		
Corporation 6		
Corporation 7		
Corporation 8		

Part 2 Income Tax Information

	Federal Taxable Income	Amounts Directly Allocated	Amounts Allocated to SC	SC Adjustments	SC NOL Prior Year Carryovers
Corporation 1	$ -1,703	$	$	$	$
Corporation 2					
Corporation 3					
Corporation 4					
Corporation 5					
Corporation 6					
Corporation 7					
Corporation 8					
Total					
	Equals page 1, line 1	Equals Sch. F, line 7	Equals Sch. F, line 8	Equals page 1, line 2	Equals page 1, line 5

Part 3 License Fee, Allocation, and Apportionment Information

	Tax Credited on Return	Total Capital and Paid in Surplus	Apportionment Percentage	License Fee
Corporation 1	$	$ 2,438	NONE%	$ 25
Corporation 2		1,000		25
Corporation 3				
Corporation 4				
Corporation 5				
Corporation 6				
Corporation 7				
Corporation 8				
Total				
	Equals page 1, line 15	Equals page 2, line 20	Per Schedule H	Equals page 2, line 21

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SCHEDULE N PROPERTY INFORMATION

Property Within South Carolina

	(a) Beginning Period	(b) Ending Period
1. Land		
2. Buildings		
3. Machinery and Equipment	1,002,509,338	1,017,803,179
4. Construction in Progress	12,585,129	9,930,810
5. Other Property*	1,023,094,675	1,144,524,027
TOTAL	2,038,189,142	2,172,258,016

*Please provide an explanation or listing of property from line 5 above.

Description of Property	(a) Beginning Period	(b) Ending Period
Other Tang. Personal Property	995,863,172	1,114,511,261
Miscellaneous Other	24,000,296	25,835,508
TOTAL	1,019,863,468	1,140,346,769

1062

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STATE OF SOUTH CAROLINA
CORPORATE TAX CREDITS

SC1120-TC
(Rev. 8/18/16)
3370

NAME OF CORPORATION
SCANA CORPORATION

FEIN
▶ 57-0784499

SC FILE #
▶ 20119164-6

These credits are computed on separate forms. Be sure to attach the appropriate form(s) to this schedule for the credit you are claiming.

Part I Corporate Income Tax Credits

	Column A Previously Accrued	Column B Earned This Year	Column C Taken This Year	Column D Lost Due to Statute	Column E Carried Forward
1. New Jobs Credit (TC-4) ▶		2,129,250			2,129,250
2. Capital Investment Credit (TC-11) ▶		4,765,784	2,938,228		1,827,556
3. Family Independence Payments Credit (TC-12) ▶					
4. Research Expenses Credit (TC-18) ▶					

For lines 5-12, enter any other credit description and associated code from Part I Codes, along with the credit amount.

Part I Credit Description	Part I Code	Column A Previously Accrued	Column B Earned This Year	Column C Taken This Year	Column D Lost Due to Statute	Column E Carried Forward
5. ▶						
6. ▶						
7. ▶						
8. ▶						
9. ▶						
10. ▶						
11. ▶						
12. ▶						
13. Total of Lines 1-12			6,915,034	2,958,228		3,956,806

PART II Corporate License Fee Credits page 2

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SC1120TC Page 2

**ENTER ANY CREDIT DESCRIPTION AND ASSOCIATED CODE FROM PART II CODES, ALONG WITH THE CREDIT AMOUNT.

Part II Corporate License Fee Credits

	Part II Credit Description	Part II Code	Column A Previously Accrued	Column B Earned This Year	Column C Taken This Year	Column D Lost Due to Statute	Column E Carried Forward
1.							
2.							
3.							
4.							
5.							
6.							
7.	Total Corporate License Fee Credits (See Instructions)			22,104,148	8,675,367		13,428,781

SEE CREDITS DESCRIPTIONS ON THE FOLLOWING PAGES

Instructions for Part I Corporate Income Tax Credits

NOTE: For consolidated returns, attach a consolidated SC1120TC.

Line 13 - Total Columns A through E

The Total of **Column A, Previously Accrued** should be entered on Schedule C, Line 1 of the SC1120, SC1120U, SC990-T.

The Total of **Column B, Earned This Year** should be entered on Schedule C, Line 2 of the SC1120, SC1120U, SC990-T.

The Total of **Column C, Taken This Year** should be the amount shown on Schedule C, Line 5 of the SC1120, SC1120U, or SC990-T, as applicable. On the SC1120S this will be passed through to the shareholders and shown on their SC1120S-K1. Enter credits taken on SC 1101B and SC1104, as applicable.

The Total of **Column D, Lost due to Statute** should be the amount shown on Schedule C, Line 6 of the SC1120, SC1120U, or SC990-T, as applicable.

The Total of **Column E, Carried Forward** should be the amount shown on Schedule C, Line 7 of the SC1120, SC1120U, or SC990-T, as applicable. Do not include credits passed through to shareholders.

Instructions for Part II Corporate License Fee Credits

Line 7 - Total Columns A through E.

The Total of Column C, **Taken This Year** should be entered on Line 22 of the SC1120 or Line 16 of the SC1120S. The credits on this form cannot be used to offset license fees on the SC1120U or the CL-4 returns. For a credit against these license fees see Section 12-20-105 of the South Carolina Code of Laws.

DEFINITIONS:

PREVIOUSLY ACCRUED: Credits earned but not used in previous years and still available for use in current or future years.

LOST DUE TO STATUTE: Credits previously earned but lost due to expiration of the time period for claiming them during this tax year.

CARRIED FORWARD: Credits not used but still available for future use. Do not include credits passed through to shareholders.

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SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 1 Detail

Schedule A and B

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION 57-0784499
Additions to federal net income				
1. Taxes on or measured by income	1,565,017			1,565,017
2. Federal net operating loss			NONE	NONE
3.				
4. Amortization Adjustment	3,237,765			3,237,765
5. Other additions	158,012,926			158,012,926
6. Total additions	162,815,708			162,815,708
Deductions from federal net income				
7. Interest on obligations of the U.S.	15,820			15,820
8.				
9. Amortization Adjustment	7,131,509			7,131,509
10. Other deductions	38,783,507			38,783,507
11. Total deductions	45,930,836			45,930,836
12. Net adjustment	116,884,872			116,884,872

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 1 Detail

Schedule A and B

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC AND GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	57-0850977	57-1007394	56-2128483
Additions to federal net income								
1. Taxes on or measured by income		10,000				1,256,602		298,415
2. Federal net operating loss								
3. ...								
4. Amortization Adjustment ...		2,139,118				1,098,647		
5. Other additions		16,536,356	117,298,992		23,222,275	955,303		
6. Total additions		18,685,474	117,298,992		23,222,275	3,310,552		298,415
Deductions from federal net income								
7. Interest on obligations of the U.S.	15,820							
8. ...								
9. Amortization Adjustment ...		3,533,838	2,073,011			1,524,660		
10. Other deductions		14,182,095	2,658,805		21,723,859	218,748		
11. Total deductions	15,820	17,715,933	4,731,816		21,723,859	1,743,408		
12. Net adjustment	-15,820	969,541	112,567,176		1,498,416	1,567,144		298,415

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 1 Detail

Schedule A and B

	CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
Additions to federal net income		
1. Taxes on or measured by income		
2. Federal net operating loss		
3.		
4. Amortization Adjustment		
5. Other additions		
6. Total additions		
Deductions from federal net income		
7. Interest on obligations of the U.S.		
8.		
9. Amortization Adjustment		
10. Other deductions		
11. Total deductions		
12. Net adjustment		

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 1 Detail

SC TAXABLE INCOME

	Combined	Adjustments	SCANA CORPORATION 57-0784499
Computation of Taxable Income			
1. Total net income as reconciled	50,438,680	3,584,036	54,022,716
2. Less: alloc. income to S.C. and other states			
3. Total net income subject to apportionment	50,438,680		50,438,680
Ratio			83.978500
4. South Carolina apportionment amount	59,164,551		59,164,551
5. Add: allocable income to S.C.			
6. Total S.C. net income	59,164,551.		59,164,551.

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 1 Detail

SC TAXABLE INCOME

	SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483
Computation of Taxable Income								
1. Total net income as reconciled	-66,004,319	11,655,246	82,830,564	9,719,948	11,054,044	49,754,299	-1,192,180	-47,378,922
2. Less: alloc. income to S.C. and other states								
3. Total net income subject to apportionment	-66,004,319	11,655,246	82,830,564	9,719,948	11,054,044	49,754,299	-1,192,180	-47,378,922
Ratio	100.000000	98.190500	97.408100	100.000000	100.000000	27.051000	100.000000	NONE
4. South Carolina apportionment amount	-66,004,319	11,444,344	80,683,679	9,719,948	11,054,044	13,459,035	-1,192,180	NONE
5. Add: allocable income to S.C.								
6. Total S.C. net income	-66,004,319	11,444,344	80,683,679	9,719,948	11,054,044	13,459,035	-1,192,180	NONE

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 1 Detail

SC TAXABLE INCOME

	CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
Computation of Taxable Income		
1. Total net income as reconciled		
2. Less: alloc. income to S.C. and other states		
3. Total net income subject to apportionment ...		
Ratio		
4. South Carolina apportionment amount		
5. Add: allocable income to S.C.		
6. Total S.C. net income		

South Carolina SC1120, Page 2 Detail - Computation of License Fee

Company name	Tot. cap. & Paid in surplus	Apportionment %	Apportioned Capital	License fee due
SCANA CORPORATION	2,341,403,986.	100.000000	2,341,403,986	2,341,419
SCANA SERVICES INC	6,850,916.	98.190500	6,726,949	6,742
SOUTH CAROLINA ELECTRIC and GAS COMPANY	2,860,337,459.	97.408100	2,786,200,372	14,284,476
SOUTH CAROLINA FUEL CO INC	2,696,226.	100.000000	2,696,226	2,711
SC GENERATING COMPANY INC	52,307,572.	100.000000	52,307,572	163,211
SCANA ENERGY MARKETING INC	44,671,574.	27.051000	12,084,107	12,099
SERVICECARE INC		100.000000		
PUBLIC SERVICE COMPANY OF NORTH CAROLINA	633,188,818.	NONE		25
CLEAN ENERGY ENTERPRISES INC			2,438	25
SCANA CORPORATE SECURITY SERVICES INC			1,000	25

South Carolina SC1120, Page 2 Detail - Computation of License Fee

Company name	Tot. cap. & Paid in surplus	Apportionment %	Apportioned Capital	License fee due
Total license fee due	5,941,456,551		5,262,670,500	16,810,733

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 2 Detail

Sch. A, Line 5 - Other additions

Depr. Adj. for Job Creation and Workers' Assistance Act	15,840,260.
Gain or loss on sale of qualifying property	696,096.
Total	16,536,356.

Sch. B, Line 10 - Other deductions

Depr. Adj. for Job Creation and Workers' Assistance Act	12,789,903.
Gain or loss on sale of qualifying property	1,392,192.
Total	14,182,095.

South Carolina SC1120, Page 2 Detail

Sch. A, Line 5 - Other additions

	3,065,841.
Depr. Adj. for Job Creation and Workers' Assistance Act	114,233,151.
Domestic Production Activities Deduction	NONE
Total	117,298,992.

Sch. B, Line 10 - Other deductions

	2,223,379.
	435,426.
Total	2,658,805.

South Carolina SC1120, Page 2 Detail

Sch. A, Line 5 - Other additions

FEDERAL DEPRECIATION	19,590,347.
FEDERAL AMORTIZATION	101,793.
FEDERAL LOSS ON SALE ASSETS	3,530,135.
Total	23,222,275.

Sch. B, Line 10 - Other deductions

SC DEPRECIATION	18,118,235.
SC AMORTIZATION	203,587.
SC LOSS ON SALE OF ASSETS	3,402,037.
Total	21,723,859.

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 2 Detail

Sch. A, Line 5 - Other additions

Depr. Adj. for Job Creation and Workers' Assistance Act	955,303.
Total	955,303.

Sch. B, Line 10 - Other deductions

Depr. Adj. for Job Creation and Workers' Assistance Act	218,748.
Total	218,748.

South Carolina SC1120, Page 3 Detail

Sch. D, Line 4 - Location of Principal Office

220 OPERATION WAY		
CAYCE	SC	29033

Sch. D, Line 12 - Location of Books

220 OPERATION WAY		
CAYCE	SC	29033

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY		
CAYCE	SC	29033

Sch. J, Line 12 - Location of Books

220 OPERATION WAY		
CAYCE	SC	29033

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY		
CAYCE	SC	29033-3701

Sch. J, Line 12 - Location of Books

220 OPERATION WAY		
CAYCE	SC	29033-3701

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY		
CAYCE	SC	29033

Sch. J, Line 7 - Directors and Principal Officers in the Corporation

Name	Title	Business Address
K R JACKSON	Other	
R M SENN	Other	
J B ARCHIE	Other	
W J TURNER III	Vice President	
T D GATLIN	Vice President	
K B MARSH	President	
D F KASSIS	Vice President	
S O SHULER JR	Vice President	
D R HARRIS	President	
S L DOZIER	Vice President	
W K KISSAM	President	
S D BURCH	Other	
J E ADDISON	Other	
F R HOWARD	Vice President	
C B LOVE	Vice President	
S A BYRNE	Other	
P N XANTHAKOS	Vice President	
J M LANDRETH	Vice President	
J E SWAN IV	Other	
G S CHAMPION	Secretary	
M S RANDALL	Vice President	
R T LINDSAY	Other	
R A JONES	Vice President	
A C HIGGINS	Vice President	

Sch. J, Line 12 - Location of Books

220 OPERATION WAY		
CAYCE	SC	29033

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 Operation Way		
Cayce	SC	29033

Sch. J, Line 12 - Location of Books

220 Operation Way		
Cayce	SC	29033

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY
CAYCE SC 29033

Sch. J, Line 12 - Location of Books

220 OPERATION WAY B126
CAYCE SC 29033

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY		
CAYCE	SC	29033

Sch. J, Line 12 - Location of Books

220 OPERATION WAY		
CAYCE	SC	29033

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY CAYCE	SC	29033-3701

Sch. J, Line 12 - Location of Books

220 OPERATION WAY CAYCE	SC	29033-3701

SCANA CORPORATION 57-0784499

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY		
CAYCE	SC	29033

Sch. J, Line 12 - Location of Books

220 OPERATION WAY		
CAYCE	SC	29033

South Carolina SC1120, Page 5 Detail

Sch. J, Line 12 - Location of Books

800 GASTON ROAD BLDG A		
GASTONIA	NC	28054

South Carolina SC1120, Page 5 Detail

Sch. J, Line 4 - Location of Principal Office

220 OPERATION WAY		
CAYCE	SC	29033

Sch. J, Line 12 - Location of Books

220 OPERATION WAY		
CAYCE	SC	29033

1039

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

NEW JOBS CREDIT

(ATTACH TO RETURN)

SC SCH.TC 4
(Rev. 9/2/16)
3117
2016

SSN or FEIN
57-0248695

NUMBER OF FULL TIME EMPLOYEES SUBJECT TO WITHHOLDING DURING EACH MONTH

COUNTY [redacted] YR 2010 YR 2011 YR 2012 YR 2013 YR 2014 2015 2016

MONTH	PRIOR YEAR	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6
1 JANUARY	[redacted]						
2 FEBRUARY							
3 MARCH							
4 APRIL							
5 MAY							
6 JUNE							
7 JULY							
8 AUGUST							
9 SEPTEMBER							
10 OCTOBER							
11 NOVEMBER							
12 DECEMBER							
LINE 1: TOTAL EMPLOYEES							
LINE 2: DIVIDED BY: NUMBER OF MONTHS IN OPERATION							
LINE 3: MONTHLY AVERAGE OF FULL TIME EMPLOYEES							
LINE 4: LESS: PREVIOUS YEAR AVERAGE							
LINE 5: AVERAGE INCREASE IN FULL TIME EMPLOYEES							

COMPUTATION OF EMPLOYEES ELIGIBLE FOR CREDIT

	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6
LINE 6: YEAR 1 INCREASE	[redacted]				
LINE 7: YEAR 2 INCREASE					
LINE 8: YEAR 3 INCREASE					
LINE 9: YEAR 4 INCREASE					
LINE 10: YEAR 5 INCREASE					
LINE 11: YEAR 6 INCREASE					
LINE 12: NUMBER OF NEW JOBS FOR CREDIT (add lines 6 through 11)					

STOP if you have fewer than 10 full time jobs or full time job equivalents for the tax year. 10 is the minimum necessary for most types of qualifying businesses.

LINE 13: AMOUNT OF CREDIT PER EMPLOYEE	[redacted]
LINE 14: ELIGIBLE CREDIT (multiply line 12 by line 13)	
LINE 15: UNUSED NEW JOBS CREDIT CARRYOVER	
LINE 16: TOTAL ELIGIBLE CREDIT (add lines 14 and 15)	
LINE 17: TAX LIABILITY (from appropriate line of tax return)	
LINE 18: TENTATIVE CREDIT (50% line 17)	
LINE 19: ENTER the lesser of line 16 or 18	

31171028

1062 THO 6W4932 1 000

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

INFRASTRUCTURE CREDIT

Attach this form to your return.

SC SCH. TC 6
(Rev. 5/30/13)
3240
20 16

Name of Corporation	FEIN
SCANA Corporation	57-0784499
Address of Corporation	
220 Operation Way, Cayce, SC 29033-3701	

COMPUTATION OF TAX CREDIT

PART I WATER LINES

A separate Sch. TC-6 must be prepared for each water line project.

1.	Expenses of water lines project and related facilities. (Project must be dedicated to public use or deeded to a qualified private entity. See instructions, paragraph B)	1.	$
2.	Expenses allocated to taxpayer's benefit. (See instructions, paragraph C)	2.	
3.	Subtract line 2 from line 1	3.	
4.	Contributions (See instructions, paragraph D)	4.	
5.	Combine lines 3 and 4	5.	
6.	Multiply amount on line 5 by 50%	6.	
7.	*Maximum credit allowed per project*	7.	$10,000
8.	Enter the lesser of lines 6 or 7. Credit amount on line 8 is combined with credit amounts from other qualifying infrastructure projects and entered on form SC1120-TC	8.	

PART II SEWER LINES

A separate Sch. TC-6 must be prepared for each sewer line project.

1.	Expenses of sewer lines project and related facilities. (Project must be dedicated to public use or deeded to a qualified private entity. See instructions, paragraph B)	1.	$
2.	Expenses allocated to taxpayer's benefit (See instructions, paragraph C)	2.	
3.	Subtract line 2 from line 1	3.	
4.	Contributions (See instructions, paragraph D)	4.	
5.	Combine lines 3 and 4	5.	
6.	Multiply amount on line 5 by 50%	6.	
7.	Maximum credit allowed per project	7.	$10,000
8.	Enter the lesser of lines 6 or 7. Credit amount on line 8 is combined with credit amounts from other qualifying infrastructure projects and entered on form SC1120-TC	8.	

Lexington County - Assist with road improvement

32401036

6W4933 1.000

THO

PART III ROADS

A separate Sch. TC-6 must be prepared for each road project.

1.	Expenses of road project. (Project must be dedicated to public use. See instructions, paragraph B)	1.	
2.	Expenses allocated to taxpayer's benefit. (See instructions, paragraph C)	2.	$
3.	Subtract line 2 from line 1	3.	
4.	Contributions 2014 Expenditure (See instructions, paragraph D)	4.	100,000.00
5.	Combine lines 3 and 4	5.	100,000.00
6.	Multiply amount on line 5 by 50%	6.	50,000.00
7.	Maximum credit allowed per project	7.	$10,000
8.	Enter the lesser of lines 6 or 7. Credit amount on line 8 is combined with credit amounts from other qualifying infrastructure projects and entered on form SC1120-TC	8.	10,000.00

Recapture of Infrastructure Credit if a Road is removed from State Highway or Public Road System

1.	Expenses (or contributions) of road project	1.	
2.	Expenses allocated to road project removed from state or public system	2.	
3.	Divide amount on line 2 by amount on line 1	3.	%
4.	Credit allowed for roads project	4.	
5.	Multiply amount on line 4 by percentage on line 3. Amount on line 5 must be added to income tax due	5.	

Effective June 6, 2006, a taxpayer can claim the infrastructure credit against bank tax.

GENERAL INSTRUCTIONS FOR SC SCH. TC 6

Be sure to ATTACH any necessary documents. See item E below.

A. South Carolina Code § 12-6-3420 allows a corporate taxpayer a credit against income tax imposed on corporations an amount equal to 50%, not to exceed $10,000 annually, of expenses paid or accrued by the taxpayer in building or improving any one infrastructure project. Effective June 6, 2006, the credit can be claimed against bank tax. Any unused credit up to a total of $30,000 may be carried forward three years.

B. For purposes of this credit, an infrastructure project includes water lines, sewer lines, their related facilities and roads that:
(1) do not exclusively benefit the taxpayer;
(2) are built to applicable standards;
(3) are dedicated to public use or, in the case of water and sewer lines and their related facilities in areas served by a private water and sewer company, the water and sewer lines are deeded to a qualified private entity.

Lexington County - Assist with road improvement

32402034

1062

6W4932 1.000

THO

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

INFRASTRUCTURE CREDIT

Attach this form to your return.

SC SCH. TC-6
(Rev. 5/30/13)
3240

20 16

Name of Corporation	FEIN
SCANA Corporation	57-0784499
Address of Corporation	
220 Operation Way, Cayce, SC 29033-3701	

COMPUTATION OF TAX CREDIT
PART I WATER LINES

A separate Sch. TC-6 must be prepared for each water line project.

1.	Expenses of water lines project and related facilities. (Project must be dedicated to public use or deeded to a qualified private entity. See instructions, paragraph B)	1.	$
2.	Expenses allocated to taxpayer's benefit (See instructions, paragraph C)	2.	
3.	Subtract line 2 from line 1	3.	
4.	Contributions (See instructions, paragraph D)	4.	
5.	Combine lines 3 and 4	5.	
6.	Multiply amount on line 5 by 50%	6.	
7.	Maximum credit allowed per project	7.	$10,000
8.	Enter the lesser of lines 6 or 7. Credit amount on line 8 is combined with credit amounts from other qualifying infrastructure projects and entered on form SC1120-TC	8.	

PART II SEWER LINES

A separate Sch. TC-6 must be prepared for each sewer line project.

1.	Expenses of sewer lines project and related facilities. (Project must be dedicated to public use or deeded to a qualified private entity. See instructions, paragraph B)	1.	$
2.	Expenses allocated to taxpayer's benefit (See instructions, paragraph C)	2.	
3.	Subtract line 2 from line 1	3.	
4.	Contributions (See instructions, paragraph D)	4.	
5.	Combine lines 3 and 4	5.	
6.	Multiply amount on line 5 by 50%	6.	
7.	Maximum credit allowed per project	7.	$10,000
8.	Enter the lesser of lines 6 or 7. Credit amount on line 8 is combined with credit amounts from other qualifying infrastructure projects and entered on form SC1120-TC	8.	

Charleston County Economic Development - Assist with county road improvement

32401036

6W4933 1.000

THO

PART III ROADS

A separate Sch. TC-6 must be prepared for each road project.

1. Expenses of road project. (Project must be dedicated to public use. See instructions, paragraph B)	1.	
2. Expenses allocated to taxpayer's benefit. (See instructions, paragraph C)	2.	$
3. Subtract line 2 from line 1	3.	
4. Contributions (See instructions, paragraph D)	4.	5,000,000.00
5. Combine lines 3 and 4	5.	5,000,000.00
6. Multiply amount on line 5 by 50%	6.	2,500,000.00
7. Maximum credit allowed per project	7.	$10,000
8. Enter the lesser of lines 6 or 7. Credit amount on line 8 is combined with credit amounts from other qualifying infrastructure projects and entered on form SC1120-TC	8.	10,000.00

Recapture of Infrastructure Credit if a Road is removed from State Highway or Public Road System

1. Expenses (or contributions) of road project	1.	
2. Expenses allocated to road project removed from state or public system	2.	
3. Divide amount on line 2 by amount on line 1	3.	%
4. Credit allowed for roads project	4.	
5. Multiply amount on line 4 by percentage on line 3. Amount on line 5 must be added to income tax due	5.	

Effective June 6, 2006, a taxpayer can claim the infrastructure credit against bank tax.

GENERAL INSTRUCTIONS FOR SC SCH. TC 6

Be sure to ATTACH any necessary documents. See item E below.

A. South Carolina Code §12-6-3420 allows a corporate taxpayer a credit against income tax imposed on corporations an amount equal to 50%, not to exceed $10,000 annually, of expenses paid or accrued by the taxpayer in building or improving any one infrastructure project. Effective June 6, 2006, the credit can be claimed against bank tax. Any unused credit up to a total of $30,000 may be carried forward three years.

B. For purposes of this credit, an infrastructure project includes water lines, sewer lines, their related facilities and roads that:
(1) do not exclusively benefit the taxpayer;
(2) are built to applicable standards;
(3) are dedicated to public use or, in the case of water and sewer lines and their related facilities in areas served by a private water and sewer company, the water and sewer lines are deeded to a qualified private entity.

Charleson County Economic Development - Assist with county road improvement

32402034

4B4949 2.000

1062

THO

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

CAPITAL INVESTMENT CREDIT

Attach to your Income Tax Return

SC SCH.TC 11
(Rev. 7/24/14)
3348

20 16

Name as Shown on Tax Return	County	SSN or FEIN
SOUTH CAROLINA GENERATING COMPANY, INC.		57-0784498

IMPORTANT: Use 2010 version of this form to claim credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. Prior year forms are available at www.dor.sc.gov.

Purpose: Use this form to claim the capital investment credit **for qualified investments made in this State on or after January 1, 2011.** This schedule must be completed and filed with the income tax return in order to claim a capital investment credit for the cost basis of qualified manufacturing and productive equipment property.

Read the definitions on the reverse side carefully before completing this schedule.

Enter qualified manufacturing and productive equipment property on the schedule below.

NOTE: Qualified property is property used as an integral part of manufacturing or production or used as an integral part of extracting of or furnishing transportation, communications, electrical energy, gas, water or sewage disposal services in this State and meets other requirements of SC Code Section 12-14-60. **Credit cannot be taken on property transferred from somewhere else unless the original use of such property commences with the taxpayer inside the State on or after January 1, 2011 or in an Economic Impact Zone before January 1, 2011.** ***Recapture of the credit will be required if the taxpayer disposes of or removes the property from this State before the end of the applicable recovery period of the property.***

		(1) Basis	(2) Credit Percentage		(3) Credit Amount (column 1 x column 2)
1.	Three-year Property		0.5%	1.	
2.	Five-year Property		1.0%	2.	
3.	Seven-year Property		1.5%	3.	
4.	Ten-year Property		2.0%	4.	
5.	Fifteen-year Property or greater	1,808,615	2.5%	5.	45,215
6.	Total of lines 1 through 5			6.	45,215
7.	Unused credits from 1997 and later that are available to carry forward.			7.	
8.	Credit - Total of lines 6 and 7			8.	45,215
	Complete line 9 if subject to the license fee for utilities in SC Code Section 12-20-100.				
9.	**Utilities only:** Enter amount from the Worksheet in the instructions.			9.	
10.	The lesser of lines 8 and 9. This is your total credit available for the current year.			10.	45,215

33481029

1062 0W4975 1.000

THO

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
3349
20 16

Name as Shown on Tax Return: SOUTH CAROLINA GENERATING COMPANY, INC.

Social Security or Employer ID Number: 57-0784498

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/02
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					3,017
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					151
6. Number of full months between the date on line 1 and the date on line 2					168
7. Recapture percentage (from worksheet below)				0.00	6.67
8. Tentative recapture tax (line 7 times line 5)					10

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 10

Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 168
4. Subtract line 3 from line 2 12
5. Recapture Percentage - Divide line 4 by line 2 . . . . . 6.67

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
3349
20 16

Name as Shown on Tax Return: SOUTH CAROLINA GENERATING COMPANY, INC.

Social Security or Employer ID Number: 57-0784498

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/04
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					2,215,573
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					110,779
6. Number of full months between the date on line 1 and the date on line 2					144
7. Recapture percentage (from worksheet below)				0.00	20.00
8. Tentative recapture tax (line 7 times line 5)					22,156

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 22,156
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 144
4. Subtract line 3 from line 2 36
5. Recapture Percentage - Divide line 4 by line 2. . . . . 20.00

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
3349
20 16

Name as Shown on Tax Return: SOUTH CAROLINA GENERATING COMPANY, INC.

Social Security or Employer ID Number: 57-0784498

	Properties				
	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/10
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					709,871
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					35,494
6. Number of full months between the date on line 1 and the date on line 2					144
7. Recapture percentage (from worksheet below)				0.00	60.00
8. Tentative recapture tax (line 7 times line 5)					21,296

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount. 21,296
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 72
4. Subtract line 3 from line 2 108
5. Recapture Percentage - Divide line 4 by line 2. . . . . . 60.00

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE
RECAPTURE OF CAPITAL INVESTMENT CREDIT
Attach this form to your return.

SC SCH.TC-11R
(Rev. 7/30/14)
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20 16

Name as Shown on Tax Return: SOUTH CAROLINA GENERATING COMPANY, INC.

SSN or FEIN: 57-0784498

IMPORTANT:
Use 2010 version of this form for recapture of credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. See instructions.

	Properties				
	A 3-year	**B** 5-year	**C** 7-year	**D** 10-year	**E** 15-year or greater
1. Date property was placed in service					7/1/2014
2. Date of disposal or removal from this State					7/1/2016
3. Cost or other basis					3,370
4. Applicable percentage	0.5%	1%	1.5%	2%	2.5%
5. Amount of credit claimed (line 4 times line 3)					84
6. Number of full months between the date on line 1 and the date on line 2					24
7. Recapture percentage (from worksheet below)	86.67	86.67	86.67	86.67	86.67
8. Tentative recapture tax (line 7 times line 5)					73

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 73
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 24
4. Subtract line 3 from line 2 156
5. Recapture Percentage - Divide line 4 by line 2 . . . . 86.67

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

CAPITAL INVESTMENT CREDIT

Attach to your Income Tax Return

SC SCH.TC 11
(Rev. 7/24/14)
3348

20 16

Name as Shown on Tax Return	County	SSN or FEIN
SOUTH CAROLINA ELECTRIC & GAS COMPANY		57-0248695

IMPORTANT: Use 2010 version of this form to claim credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. Prior year forms are available at www.dor.sc.gov.

Purpose: Use this form to claim the capital investment credit for **qualified investments made in this State on or after January 1, 2011.** This schedule must be completed and filed with the income tax return in order to claim a capital investment credit for the cost basis of qualified manufacturing and productive equipment property.

Read the definitions on the reverse side carefully before completing this schedule.

Enter qualified manufacturing and productive equipment property on the schedule below.

NOTE: Qualified property is property used as an integral part of manufacturing or production or used as an integral part of extracting of or furnishing transportation, communications, electrical energy, gas, water or sewage disposal services in this State and meets other requirements of SC Code Section 12-14-60. **Credit cannot be taken on property transferred from somewhere else unless the original use of such property commences with the taxpayer inside the State on or after January 1, 2011 or in an Economic Impact Zone before January 1, 2011. Recapture of the credit will be required if the taxpayer disposes of or removes the property from this State before the end of the applicable recovery period of the property.**

		(1) Basis	(2) Credit Percentage		(3) Credit Amount (column 1 x column 2)
1.	Three-year Property		0.5%	1.	
2.	Five-year Property		1.0%	2.	
3.	Seven-year Property		1.5%	3.	
4.	Ten-year Property		2.0%	4.	
5.	Fifteen-year Property or greater	362,784,984	2.5%	5.	9,069,625
6.	Total of lines 1 through 5			6.	9,069,625
7.	Unused credits from 1997 and later that are available to carry forward.			7.	
8.	Credit - Total of lines 6 and 7. **Complete line 9 if subject to the license fee for utilities in SC Code Section 12-20-100.**			8.	9,069,625
9.	**Utilities only:** Enter amount from the Worksheet in the instructions.			9.	
10.	The lesser of lines 8 and 9. This is your total credit available for the current year.			10.	5,000,000

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE
RECAPTURE OF CAPITAL INVESTMENT CREDIT
Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/30/14)
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20 16

Name as Shown on Tax Return	SSN or FEIN
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

IMPORTANT:
Use 2010 version of this form for recapture of credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. See instructions.

	Properties				
	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/15
2. Date of disposal or removal from this State					7/1/16
3. Cost or other basis					685,471
4. Applicable percentage	0.5%	1%	1.5%	2%	2.5%
5. Amount of credit claimed (line 4 times line 3)					17,137
6. Number of full months between the date on line 1 and the date on line 2					12
7. Recapture percentage (from worksheet below)					93.33
8. Tentative recapture tax (line 7 times line 5)					15,994

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 15,994
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 12
4. Subtract line 3 from line 2 168
5. Recapture Percentage - Divide line 4 by line 2. . . . . 93.33

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF CAPITAL INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/30/14)
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20 16

Name as Shown on Tax Return	SSN or FEIN
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

IMPORTANT:

Use 2010 version of this form for recapture of credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. See instructions.

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/14
2. Date of disposal or removal from this State					7/1/16
3. Cost or other basis					476,974
4. Applicable percentage	0.5%	1%	1.5%	2%	2.5%
5. Amount of credit claimed (line 4 times line 3)					11,924
6. Number of full months between the date on line 1 and the date on line 2					24
7. Recapture percentage (from worksheet below)					86.67
8. Tentative recapture tax (line 7 times line 5)					10,335

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount. 10,335
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table. 180
3. Number of months from line 6 Form TC-11-R 24
4. Subtract line 3 from line 2 156
5. Recapture Percentage - Divide line 4 by line 2. . . . . 86.67

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF CAPITAL INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
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Name as Shown on Tax Return	SSN or FEIN
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

IMPORTANT:
Use 2010 version of this form for recapture of credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. See instructions.

	Properties				
	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/13
2. Date of disposal or removal from this State					7/1/16
3. Cost or other basis					722,340
4. Applicable percentage	0.5%	1%	1.5%	2%	2.5%
5. Amount of credit claimed (line 4 times line 3)					18,059
6. Number of full months between the date on line 1 and the date on line 2					36
7. Recapture percentage (from worksheet below)					80.00
8. Tentative recapture tax (line 7 times line 5)					14,447

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 14,447
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 36
4. Subtract line 3 from line 2 144
5. Recapture Percentage - Divide line 4 by line 2 . . . . 80.00

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE
RECAPTURE OF CAPITAL INVESTMENT CREDIT
Attach this form to your return.

SC SCH.TC 11-R
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Name as Shown on Tax Return	SSN or FEIN
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

IMPORTANT:

Use 2010 version of this form for recapture of credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. See instructions.

	Properties				
	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/12
2. Date of disposal or removal from this State					7/1/16
3. Cost or other basis					3,526,763
4. Applicable percentage	0.5%	1%	1.5%	2%	2.5%
5. Amount of credit claimed (line 4 times line 3)					88,169
6. Number of full months between the date on line 1 and the date on line 2					48
7. Recapture percentage (from worksheet below)					73.33
8. Tentative recapture tax (line 7 times line 5)					64,654

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 64,654
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 48
4. Subtract line 3 from line 2 132
5. Recapture Percentage - Divide line 4 by line 2 . . . . . 73.33

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF CAPITAL INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
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20 16

Name as Shown on Tax Return	SSN or FEIN
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

IMPORTANT:

Use 2010 version of this form for recapture of credit for qualifying investments made in an Economic Impact Zone before January 1, 2011. See instructions.

	Properties				
	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/11
2. Date of disposal or removal from this State					7/1/16
3. Cost or other basis					1,089,696
4. Applicable percentage	0.5%	1%	1.5%	2%	2.5%
5. Amount of credit claimed (line 4 times line 3)					27,242
6. Number of full months between the date on line 1 and the date on line 2					60
7. Recapture percentage (from worksheet below)					66.67
8. Tentative recapture tax (line 7 times line 5)					18,162

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 18,162
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet

Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 60
4. Subtract line 3 from line 2 120
5. Recapture Percentage - Divide line 4 by line 2. . . . . . 66.67

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

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Name as Shown on Tax Return	Social Security or Employer ID Number
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

	Properties				
	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/10
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					167,573
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					8,379
6. Number of full months between the date on line 1 and the date on line 2					72
7. Recapture percentage (from worksheet below)				0.00	60.00
8. Tentative recapture tax (line 7 times line 5)					5,027

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 5,027
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 72
4. Subtract line 3 from line 2 108
5. Recapture Percentage - Divide line 4 by line 2. . . . . 60.00

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
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Name as Shown on Tax Return: SOUTH CAROLINA ELECTRIC & GAS COMPANY

Social Security or Employer ID Number: 57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/09
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					691,636
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					34,582
6. Number of full months between the date on line 1 and the date on line 2					84
7. Recapture percentage (from worksheet below)				0.00	53.33
8. Tentative recapture tax (line 7 times line 5)					18,443

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 18,443
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 84
4. Subtract line 3 from line 2 96
5. Recapture Percentage - Divide line 4 by line 2 . . . . . . 53.33

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

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Name as Shown on Tax Return	Social Security or Employer ID Number
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/08
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					482,313
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					24,116
6. Number of full months between the date on line 1 and the date on line 2					96
7. Recapture percentage (from worksheet below)				0.00	46.67
8. Tentative recapture tax (line 7 times line 5)					11,255

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 11,255
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 96
4. Subtract line 3 from line 2 84
5. Recapture Percentage - Divide line 4 by line 2. . . . . 46.67

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
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20 16

Name as Shown on Tax Return	Social Security or Employer ID Number
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/07
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					1,152,047
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					57,602
6. Number of full months between the date on line 1 and the date on line 2					108
7. Recapture percentage (from worksheet below)				0.00	40.00
8. Tentative recapture tax (line 7 times line 5)					23,041

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount. 23,041
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 108
4. Subtract line 3 from line 2 72
5. Recapture Percentage - Divide line 4 by line 2. . . . . . 40.00

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

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Name as Shown on Tax Return	Social Security or Employer ID Number
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/06
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					1,284,991
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					64,250
6. Number of full months between the date on line 1 and the date on line 2					120
7. Recapture percentage (from worksheet below)				0.00	33.33
8. Tentative recapture tax (line 7 times line 5)					21,415

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount. 21,415
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 120
4. Subtract line 3 from line 2 60
5. Recapture Percentage - Divide line 4 by line 2. . . . . . 33.33

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

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20 16

Name as Shown on Tax Return	Social Security or Employer ID Number
SOUTH CAROLINA ELECTRIC & GAS COMPANY	57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/05
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					653,783
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					32,689
6. Number of full months between the date on line 1 and the date on line 2					132
7. Recapture percentage (from worksheet below)				0.00	26.67
8. Tentative recapture tax (line 7 times line 5)					8,718

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 8,718
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 132
4. Subtract line 3 from line 2 48
5. Recapture Percentage - Divide line 4 by line 2. . . . . . . 26.67

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
3349
20 16

Name as Shown on Tax Return: SOUTH CAROLINA ELECTRIC & GAS COMPANY

Social Security or Employer ID Number: 57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/04
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					904,915
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					45,246
6. Number of full months between the date on line 1 and the date on line 2					144
7. Recapture percentage (from worksheet below)				0.00	20.00
8. Tentative recapture tax (line 7 times line 5)					9,049

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 9,049

Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 144
4. Subtract line 3 from line 2 36
5. Recapture Percentage - Divide line 4 by line 2. . . . . . 20.00

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
3349
20 16

Name as Shown on Tax Return: SOUTH CAROLINA ELECTRIC & GAS COMPANY

Social Security or Employer ID Number: 57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/03
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					1,166,372
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					58,319
6. Number of full months between the date on line 1 and the date on line 2					156
7. Recapture percentage (from worksheet below)				0.00	13.33
8. Tentative recapture tax (line 7 times line 5)					7,774

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 7,774

Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 156
4. Subtract line 3 from line 2 24
5. Recapture Percentage - Divide line 4 by line 2 . . . . . 13.33

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RECAPTURE OF ECONOMIC IMPACT ZONE PROPERTY INVESTMENT CREDIT

Attach this form to your return.

SC SCH.TC 11-R
(Rev. 7/20/07)
3349
20 16

Name as Shown on Tax Return: SOUTH CAROLINA ELECTRIC & GAS COMPANY

Social Security or Employer ID Number: 57-0248695

Properties

	A 3-year	B 5-year	C 7-year	D 10-year	E 15-year or greater
1. Date property was placed in service					7/1/02
2. Date of disposal or removal from zone					7/1/16
3. Cost or other basis					2,273,594
4. Applicable percentage	1%	2%	3%	4%	5%
5. Amount of credit claimed (line 4 times line 3) *					113,680
6. Number of full months between the date on line 1 and the date on line 2					168
7. Recapture percentage (from worksheet below)				0.00	6.67
8. Tentative recapture tax (line 7 times line 5)					7,582

9. Total Recapture tax (add line 8 of columns A through E). Increase your income tax by this amount 7,582
Note: On the dotted line next to the tax line write "Includes recapture tax - Sch. TC-11-R".

Recapture Percentage Worksheet
Total Months for Each Class Life

Property	3 Year	5 Year	7 Year	10 Year	15 Year or greater
Months	36	60	84	120	180

1. Class life of property subject to recapture 15
2. Total months from above table 180
3. Number of months from line 6 Form TC-11-R 168
4. Subtract line 3 from line 2 12
5. Recapture Percentage - Divide line 4 by line 2. . . . . 6.67

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STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

RESEARCH EXPENSES CREDIT

Attach to your Income Tax or Corporate License Fee Return

SC SCH.TC-18
(Rev. 1/12/16)
3368
20 2016

Name As Shown On Tax Return	SSN or FEIN
SCANA CORPORATION	57-0784499

1. Qualified research expenses made in South Carolina	1. $	431,282,965
2. Enter 5% of line 1. This is your current year credit	2. $	21,564,148
3. Research Expenses Credit carried forward from previous years (attach schedule). (Unused Research Expenses Credit can be carried forward for up to 10 years.)	3. $	
4. Line 2 plus line 3 (Total Research Expenses Credit before limitations)	4. $	21,564,148
5. Tax Liability (income tax and license fees) before claiming credits	5. $	19,768,961
6. Total of all credits other than the Research Expenses Credit	6. $	3,498,228
7. Line 5 minus line 6 (If less than zero, enter zero)	7. $	16,270,733
8. Multiply line 7 by 50% (0.5)	8. $	8,135,367
9. Enter the lesser of line 4 or line 8 (This is the amount of Research Expenses Credit you may use this year.)	9. $	8,135,367
10. Line 4 minus line 9. (Unused Research Expenses Credit may be carried forward for up to 10 years.)	10. $	13,428,781

GENERAL INSTRUCTIONS

Effective for tax years beginning after June 30, 2001, a taxpayer claiming a federal income tax credit for research expenses (under Internal Revenue Code Section 41) may claim a credit against individual or corporate income tax and corporate license fees. The credit is 5% of the qualified research expenses, as defined by Internal Revenue Code Section 41(b), made by the taxpayer in South Carolina during the tax year.

The credit taken in any tax year may not exceed 50% of the taxpayer's tax liability remaining after all other credits are applied. Any unused credit can be carried forward but must be used before a tax year beginning 10 years or after from the date of the qualified research expenses. Credit earned in tax years beginning in 2006 or before cannot be used against individual income tax. The credit is allowed under S.C. Code Section 12-6-3415.

Social Security Privacy Act Disclosure
It is mandatory that you provide your social security number on this tax form if you are an individual taxpayer. 42 U.S.C 405(c)(2)(C)(i) permits a state to use an individual's social security number as means of identification in administration of any tax. SC Regulation 117-201 mandates that any person required to make a return to the SC Department of Revenue shall provide identifying numbers, as prescribed, for securing proper identification. Your social security number is used for identification purposes.

The Family Privacy Protection Act
Under the Family Privacy Protection Act, the collection of personal information from citizens by the Department of Revenue is limited to the information necessary for the Department to fulfill its statutory duties. In most instances, once this information is collected by the Department, it is protected by law from public disclosure. In those situations where public disclosure is not prohibited, the Family Privacy Protection Act prevents such information from being used by third parties for commercial solicitation purposes.

SCANA Corporation & Subsidiaries
Sch TC 11
FEIN: 57-0784499
SC File # - 20119164-6
For the Year Ended December 31, 2016

SCANA Corporation is taking the capital investment credit in accordance with SC §12-14-60.

Accordingly, Sch TC 11 has been completed with a five million dollar maximum credit generated per year per entity applicable to utilities subject to SC Code §12-20-100.

FORM 8275 DISCLOSURE AND WAIVER STATEMENT

RE: CAPITAL INVESTMENT TAX CREDITS

SCANA Corporation and Subsidiaries
2016 South Carolina Income Tax Return

For tax year 2016, SCANA Corporation (Taxpayer) and subsidiaries of SCANA Corporation have generated tax credits pursuant to the operation of S.C. Code Section 12-14-60 (Investment Tax Credits).

In accordance with Section 12-14-60(C), SCANA Corporation and its applicable subsidiaries also expressly waive the application of any and all other tax credits with respect to the properties for which these investment tax credits are claimed.

By: ______________________
James E. Swan, IV
Controller

SCANA CORPORATION
57-0784499
FORM SC 1120
TAXABLE YEAR 12/31/16
CARRYFORWARD SCHEDULE

INCOME TAX CREDITS	PRIOR YEAR CARRYOVER	2016 EARNED	2016 UTILIZED	CARRYOVER TO 2017
INFRASTRUCTURE CREDIT		20,000	20,000	-
CAPITAL INVESTMENT CREDIT-2016-GENCO	-	1,680	1,680	-
CAPITAL INVESTMENT CREDIT-2016-SCEG	-	4,764,104	2,936,548	1,827,556
CAPITAL INVESTMENT CREDIT-2016-FUEL CO	-	-	-	-
JOBS TAX CREDIT - SCEG	-	2,129,250		2,129,250
				-
	-	6,915,034	2,958,228	3,956,806

LICENSE FEE CREDITS (SC Code 12-20-105 Tax Credit)	CARRYOVER	EARNED	UTILIZED	TO 2017
INFRASTRUCTURE CREDIT - SCEG	-	400,000	400,000	-
INFRASTRUCTURE CREDIT - GENCO		140,000	140,000	
RESEARCH CREDIT-2016-SCEG	-	21,561,230	8,132,449	13,428,781
RESEARCH CREDIT-2016-GENCO	-	2,918	2,918	-
	-	22,104,148	8,675,367	13,428,781

TOTAL INCOME AND LICENSE FEE CREDITS CARRYFORWARD	17,385,587

SC CAPITAL LOSS CARRYFORWARD	PRIOR YEAR CARRYOVER	2016 EARNED	2016 UTILIZED	CARRYOVER TO 2017
SCANA CORPORATION	0		0	0

SC CONTRIBUTION DEDUCTION CARRYFORWARD	PRIOR YEAR CARRYOVER	2016 EARNED	2016 UTILIZED	LOST DUE TO STATUTE	CARRYOVER TO 2016
SCANA CORPORATION	0	0	0		0
	0	0	0	0	0

SCANA CORPORATION

Chairman, President, Chief Executive Officer And Chief Operating Officer	Kevin B. Marsh
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Executive Vice President	Stephen A. Byrne
Senior Vice President	Jeffrey B. Archie
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President	D. Russell Harris
Senior Vice President	Kenneth R. Jackson
Senior Vice President	W. Keller Kissam
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.

March 1, 2017

SCANA SERVICES, INC.

Chairman, President, Chief Executive Officer And Chief Operating Officer	Kevin B. Marsh
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Executive Vice President	Stephen A. Byrne
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President	D. Russell Harris
Senior Vice President	Kenneth R. Jackson
Senior Vice President	W. Keller Kissam
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President	Henry E. Barton, Jr.
Vice President	Samuel L. Dozier
Vice President	Cedric F. Green
Vice President	Annmarie C. Higgins
Vice President	Catherine B. Love
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

Chairman and Chief Executive Officer	Kevin B. Marsh
Chief Operating Officer and President – Generation & Transmission	Stephen A. Byrne
President – Gas Operations	D. Russell Harris
President – Retail Operations	W. Keller Kissam
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Senior Vice President and Chief Nuclear Officer	Jeffrey B. Archie
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President	Kenneth R. Jackson
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President	Samuel L. Dozier
Vice President	Thomas D. Gatlin
Vice President	Cedric F. Green
Vice President	Annmarie C. Higgins
Vice President	Felicia R. Howard
Vice President	Ronald A. Jones
Vice President	Daniel F. Kassis
Vice President	James M. Landreth

March 1, 2017

Vice President	George A. Lippard
Vice President	Catherine B. Love
Vice President	M. Shaun Randall
Vice President	William J. Turner III
Vice President	Pandelis N. Xanthakos
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

Chairman and Chief Executive Officer	Kevin B. Marsh
President and Chief Operating Officer	D. Russell Harris
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President	William McAulay
Vice President	M. Shaun Randall
Vice President	George Ratchford
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.
Assistant Secretary	Carol G. Oshields

SCANA ENERGY MARKETING, INC.

Chairman and Chief Executive Officer	Kevin B. Marsh
President, Chief Operating Officer and Chief Financial Officer	Jimmy E. Addison
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President	George T. Devlin
Vice President	Robert G. Edwards
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.

SOUTH CAROLINA GENERATING COMPANY, INC.

Chairman, President, Chief Executive Officer And Chief Operating Officer	Kevin B. Marsh
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Executive Vice President	Stephen A. Byrne
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV

March 1, 2017

SOUTH CAROLINA FUEL COMPANY, INC.

Chairman, President, Chief Executive Officer And Chief Operating Officer	Kevin B. Marsh
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Executive Vice President	Stephen A. Byrne
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV

SCANA CORPORATE SECURITY SERVICES, INC.

Chairman and Chief Executive Officer	Kevin B. Marsh
President	Randal M. Senn
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.

CLEAN ENERGY ENTERPRISES, INC.

Chairman and Chief Executive Officer	Kevin B. Marsh
President and Chief Operating Officer	D. Russell Harris
Chief Financial Officer and Executive Vice President	Jimmy E. Addison
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President, General Counsel and Assistant Secretary	Ronald T. Lindsay
Senior Vice President	Randal M. Senn
Vice President and Secretary	Gina S. Champion
Vice President and Treasurer	Iris Griffin
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.
Assistant Secretary	Carol G. Oshields

PRO FORMA

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2016 or tax year beginning ______________, ending ______________

▶ Information about Form 1120 and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123 **2016**

A Check if:	TYPE OR PRINT		
1a Consolidated return (attach Form 851) X		Name: SCANA CORPORATION	B Employer identification number: 57-0784499
b Life/nonlife consolidated return		Number, street, and room or suite no. If a P.O. box, see instructions: 220 OPERATION WAY	C Date incorporated: 10/01/1984
2 Personal holding co. (attach Sch. PH)		City or town, state, or province, country, and ZIP or foreign postal code: CAYCE, SC 29033-3701	D Total assets (see instructions): $ 18,677,150,172.
3 Personal service corp. (see instructions)			
4 Schedule M-3 attached X		E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change	

	Line	Description			Line	Amount
Income	1a	Gross receipts or sales	1a	4,497,365,433.		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	4,497,365,433.
	2	Cost of goods sold (attach Form 1125-A)			2	2,118,180,744.
	3	Gross profit. Subtract line 2 from line 1c			3	2,379,184,689.
	4	Dividends (Schedule C, line 19)			4	337,492.
	5	Interest			5	241,216,432.
	6	Gross rents			6	15,809,392.
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	230,794.
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	-51,771,917.
	10	Other income (see instructions - attach statement) See Statement 4			10	21,604,039.
	11	**Total income.** Add lines 3 through 10 ▶			11	2,606,610,921.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E) ▶			12	15,144,833.
	13	Salaries and wages (less employment credits)			13	80,500,650.
	14	Repairs and maintenance			14	248,721,590.
	15	Bad debts			15	10,347,235.
	16	Rents			16	4,694,139.
	17	Taxes and licenses			17	256,475,476.
	18	Interest			18	385,177,623.
	19	Charitable contributions See Statement 6			19	NONE
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	674,906,524.
	21	Depletion			21	
	22	Advertising			22	12,485,413.
	23	Pension, profit-sharing, etc., plans			23	694,957.
	24	Employee benefit programs			24	56,802,808.
	25	Domestic production activities deduction (attach Form 8903)			25	
	26	Other deductions (attach statement) See Statement 7			26	923,309,629.
	27	**Total deductions.** Add lines 12 through 26 ▶			27	2,669,260,877.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11			28	-62,649,956.
	29a	Net operating loss deduction (see instructions)	29a	NONE		Stmt 10
	b	Special deductions (Schedule C, line 20)	29b	212,200.		
	c	Add lines 29a and 29b			29c	212,200.
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28. See instructions			30	-62,862,156.
	31	Total tax (Schedule J, Part I, line 11)			31	NONE
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	6,237,866.
	33	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶ ☐			33	
	34	**Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	
	35	**Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	6,237,866.
	36	Enter amount from line 35 you want: **Credited to 2017 estimated tax** ▶ **Refunded** ▶			36	6,237,866.

Sign Here Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

▶ PRO FORMA | Date | ▶ CONTROLLER

Signature of officer JAMES E SWAN IV | Title

May the IRS discuss this return with the preparer shown below? See instructions. Yes ☐ No X

Paid Preparer Use Only	Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
	Firm's name ▶			Firm's EIN ▶	
	Firm's address ▶			Phone no.	

For Paperwork Reduction Act Notice, see separate instructions. Form **1120** (2016)

JSA
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SCANA CORPORATION 57-0784499

Schedule C Dividends and Special Deductions (see instructions)

		(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1	Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	303,143.	70	212,200.
2	Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3	Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4	Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5	Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6	Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7	Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8	Dividends from wholly owned foreign subsidiaries		100	
9	Total. Add lines 1 through 8. See instructions for limitation			212,200.
10	Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11	Dividends from affiliated group members		100	
12	Dividends from certain FSCs		100	
13	Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, or 12	34,349.		
14	Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15	Foreign dividend gross-up			
16	IC-DISC and former DISC dividends not included on line 1, 2, or 3			
17	Other dividends			
18	Deduction for dividends paid on certain preferred stock of public utilities			
19	**Total dividends.** Add lines 1 through 17. Enter here and on page 1, line 4 ▶	337,492.		
20	**Total special deductions.** Add lines 9, 10, 11, 12, and 18. Enter here and on page 1, line 29b ▶			212,200.

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 3

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶				
2	Income tax. Check if a qualified personal service corporation. See instructions ▶			2	
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	NONE
5a	Foreign tax credit (attach Form 1118)	5a			
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c			
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	
7	Subtract line 6 from line 4			7	NONE
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	NONE

Part II-Payments and Refundable Credits

12	2015 overpayment credited to 2016			12	
13	2016 estimated tax payments			13	6,000,000.
14	2016 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	6,000,000.
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	**Total payments.** Add lines 15, 16, and 17			18	6,000,000.
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	237,866.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	237,866.
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	6,237,866.

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group?		X
	If "Yes," enter name and EIN of the parent corporation ▶		
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Form **1120** (2016)

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 4

Schedule K Other Information *(continued from page 3)*

	Yes	No
5 At the end of the tax year, did the corporation:		
a Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851,** Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.		X

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock

	Yes	No
b Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below. See Statement 14	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital

	Yes	No
6 During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316.		X
If "Yes," file **Form 5452,** Corporate Report of Nondividend Distributions. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7 At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of (a) the total voting power of all classes of the corporation's stock entitled to vote or (b) the total value of all classes of the corporation's stock?		X
For rules of attribution, see section 318. If "Yes," enter: (i) Percentage owned ▶ ______ and (ii) Owner's country ▶ ______		
(c) The corporation may have to file **Form 5472,** Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ ______		
8 Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐ If checked, the corporation may have to file **Form 8281,** Information Return for Publicly Offered Original Issue Discount Instruments.		
9 Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $ ______		
10 Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶ ______		
11 If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here ▶ ☐ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election won't be valid.		
12 Enter the available NOL carryover from prior tax years (don't reduce it by any deduction on line 29a.) ▶ $ ______		
13 Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year and its total assets at the end of the tax year less than $250,000?		X
If "Yes," the corporation isn't required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $ ______		
14 Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions		X
If "Yes," complete and attach Schedule UTP.		
15a Did the corporation make any payments in 2016 that would require it to file Form(s) 1099?	X	
b If "Yes," did or will the corporation file required Forms 1099?	X	
16 During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17 During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18 Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19 During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?		X

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 5

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	(b)	End of tax year (c)	(d)
1 Cash		233,257,854.		205,996,742.
2a Trade notes and accounts receivable	682,391,843.		733,184,381.	
b Less allowance for bad debts	(5,269,711.)	677,122,132.	(5,853,608.)	727,330,773.
3 Inventories		311,778,910.		290,480,845.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 21	151,782,083.		280,369,350.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 23	210,586,432.		170,864,319.
10a Buildings and other depreciable assets	18,667,897,661.		20,054,957,957.	
b Less accumulated depreciation	(5,975,136,607.)	12,692,761,054.	(5,454,272,723.)	14,600,685,234.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)				
13a Intangible assets (amortizable only)				
b Less accumulated amortization	( )		( )	
14 Other assets (attach statement)	Stmt 24	2,479,471,650.		2,401,422,909.
15 Total assets		16,756,760,115.		18,677,150,172.
Liabilities and Shareholders' Equity				
16 Accounts payable		576,642,625.		388,631,175.
17 Mortgages, notes, bonds payable in less than 1 year		647,291,449.		957,426,831.
18 Other current liabilities (attach statement)	Stmt 27	650,640,197.		716,549,283.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		5,904,834,401.		6,472,928,061.
21 Other liabilities (attach statement)	Stmt 30	3,549,178,387.		4,430,749,397.
22 Capital stock: a Preferred stock				
b Common stock	2,417,573,500.	2,417,573,500.	2,417,573,500.	2,417,573,500.
23 Additional paid-in capital		-16,506,420.		-16,506,420.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		3,104,314,288.		3,371,327,463.
26 Adjustments to shareholders' equity (attach statement)		-65,415,803.		-49,053,585.
27 Less cost of treasury stock		(11,792,509.)		(12,475,533.)
28 Total liabilities and shareholders' equity		16,756,760,115.		18,677,150,172.

Schedule M-1 **Reconciliation of Income (Loss) per Books With Income per Return**

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 **Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)**

1 Balance at beginning of year	3,104,314,288.	5 Distributions: a Cash	324,537,943.
2 Net income (loss) per books	591,551,110.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 36	-6.
See Statement 36	2.	7 Add lines 5 and 6	324,537,937.
4 Add lines 1, 2, and 3	3,695,865,400.	8 Balance at end of year (line 4 less line 7)	3,371,327,463.

SCHEDULE G (Form 1120)
(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Information on Certain Persons Owning the Corporation's Voting Stock

▶ Attach to Form 1120.
▶ See instructions on page 2.

OMB No. 1545-0123

Name	Employer identification number (EIN)
SCANA CORPORATION	57-0784499

Part I **Certain Entities Owning the Corporation's Voting Stock.** (Form 1120, Schedule K, Question 4a). Complete columns (i) through (v) below for any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization that owns directly 20% or more, or owns, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote (see instructions).

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Type of Entity	(iv) Country of Organization	(v) Percentage Owned in Voting Stock

Part II **Certain Individuals and Estates Owning the Corporation's Voting Stock.** (Form 1120, Schedule K, Question 4b). Complete columns (i) through (iv) below for any individual or estate that owns directly 20% or more, or owns, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote (see instructions).

(i) Name of Individual or Estate	(ii) Identifying Number (if any)	(iii) Country of Citizenship (see instructions)	(iv) Percentage Owned in Voting Stock

Form **4626**

Department of the Treasury
Internal Revenue Service

Alternative Minimum Tax - Corporations

▶ Attach to the corporation's tax return.

▶ Information about Form 4626 and its separate instructions is at *www.irs.gov/form4626*.

OMB No. 1545-0123

2016

Name: SCANA CORPORATION

Employer identification number: 57-0784499

Note: *See the instructions to find out if the corporation is a small corporation exempt from the alternative minimum tax (AMT) under section 55(e).*

Line	Description	Ref	Amount
1	Taxable income or (loss) before net operating loss deduction	1	-62,862,156.
2	**Adjustments and preferences:**		
a	Depreciation of post-1986 property	2a	-22,088,571.
b	Amortization of certified pollution control facilities	2b	
c	Amortization of mining exploration and development costs	2c	
d	Amortization of circulation expenditures (personal holding companies only)	2d	
e	Adjusted gain or loss	2e	1,703,217.
f	Long-term contracts	2f	
g	Merchant marine capital construction funds	2g	
h	Section 833(b) deduction (Blue Cross, Blue Shield, and similar type organizations only)	2h	
i	Tax shelter farm activities (personal service corporations only)	2i	
j	Passive activities (closely held corporations and personal service corporations only)	2j	
k	Loss limitations	2k	
l	Depletion	2l	
m	Tax-exempt interest income from specified private activity bonds	2m	
n	Intangible drilling costs	2n	
o	Other adjustments and preferences . . . See Statement 40	2o	NONE
3	Pre-adjustment alternative minimum taxable income (AMTI). Combine lines 1 through 2o	3	-83,247,510.
4	**Adjusted current earnings (ACE) adjustment:**		
a	ACE from line 10 of the ACE worksheet in the instructions	4a	-50,692,428.
b	Subtract line 3 from line 4a. If line 3 exceeds line 4a, enter the difference as a negative amount. See instructions	4b	32,555,082.
c	Multiply line 4b by 75% (0.75). Enter the result as a positive amount	4c	24,416,312.
d	Enter the excess, if any, of the corporation's total increases in AMTI from prior year ACE adjustments over its total reductions in AMTI from prior year ACE adjustments. See instructions. **Note:** *You **must** enter an amount on line 4d (even if line 4b is positive)*	4d	
e	ACE adjustment. • If line 4b is zero or more, enter the amount from line 4c • If line 4b is less than zero, enter the **smaller** of line 4c or line 4d as a negative amount	4e	24,416,312.
5	Combine lines 3 and 4e. If zero or less, stop here; the corporation does not owe any AMT	5	-58,831,198.
6	Alternative tax net operating loss deduction. See instructions . . . . See Statement 42	6	
7	**Alternative minimum taxable income.** Subtract line 6 from line 5. If the corporation held a residual interest in a REMIC, see instructions	7	-58,831,198.
8	**Exemption phase-out** (if line 7 is $310,000 or more, skip lines 8a and 8b and enter -0- on line 8c):		
a	Subtract $150,000 from line 7 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-	8a	NONE
b	Multiply line 8a by 25% (0.25)	8b	NONE
c	Exemption. Subtract line 8b from $40,000 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-	8c	40,000.
9	Subtract line 8c from line 7. If zero or less, enter -0-	9	NONE
10	Multiply line 9 by 20% (0.20)	10	NONE
11	Alternative minimum tax foreign tax credit (AMTFTC). See instructions	11	
12	Tentative minimum tax. Subtract line 11 from line 10	12	NONE
13	Regular tax liability before applying all credits except the foreign tax credit	13	
14	**Alternative minimum tax.** Subtract line 13 from line 12. If zero or less, enter -0-. Enter here and on Form 1120, Schedule J, line 3, or the appropriate line of the corporation's income tax return	14	NONE

SCANA CORPORATION 57-0784499

Adjusted Current Earnings (ACE) Worksheet

Keep for Your Records

▶ See ACE Worksheet Instructions.

1 Pre-adjustment AMTI. Enter the amount from line 3 of Form 4626			1	-83,247,510.
2 ACE depreciation adjustment:				
a AMT depreciation		2a 696,995,092.		
b ACE depreciation:				
(1) Post-1993 property	2b(1) 244,608,251.			
(2) Post-1989, pre-1994 property	2b(2)			
(3) Pre-1990 MACRS property	2b(3)			
(4) Pre-1990 original ACRS property	2b(4)			
(5) Property described in sections 168(f)(1) through (4)	2b(5)			
(6) Other property	2b(6) 451,920,654.			
(7) Total ACE depreciation. Add lines 2b(1) through 2b(6)		2b(7) 696,528,905.		
c ACE depreciation adjustment. Subtract line 2b(7) from line 2a			2c	466,187.
3 Inclusion in ACE of items included in earnings and profits (E&P):				
a Tax-exempt interest income		3a		
b Death benefits from life insurance contracts		3b -268,623.		
c All other distributions from life insurance contracts (including surrenders)		3c		
d Inside buildup of undistributed income in life insurance contracts		3d 4,986,147.		
e Other items (see Regulations sections 1.56(g)-1(c)(6)(iii) through (ix) for a partial list)		3e		
f Total increase to ACE from inclusion in ACE of items included in E&P. Add lines 3a through 3e			3f	4,717,524.
4 Disallowance of items not deductible from E&P:				
a Certain dividends received		4a 212,200.		
b Dividends paid on certain preferred stock of public utilities that are deductible under section 247 (as affected by P.L. 113-295, Div. A, section 221(a)(41)(A), Dec. 19, 2014, 128 Stat. 4043)		4b		
c Dividends paid to an ESOP that are deductible under section 404(k)		4c 27,159,171.		
d Nonpatronage dividends that are paid and deductible under section 1382(c)		4d		
e Other items (see Regulations sections 1.56(g)-1(d)(3)(i) and (ii) for a partial list)		4e		
f Total increase to ACE because of disallowance of items not deductible from E&P. Add lines 4a through 4e			4f	27,371,371.
5 Other adjustments based on rules for figuring E&P:				
a Intangible drilling costs		5a		
b Circulation expenditures		5b		
c Organizational expenditures		5c		
d LIFO inventory adjustments		5d		
e Installment sales		5e		
f Total other E&P adjustments. Combine lines 5a through 5e			5f	
6 Disallowance of loss on exchange of debt pools			6	
7 Acquisition expenses of life insurance companies for qualified foreign contracts			7	
8 Depletion			8	
9 Basis adjustments in determining gain or loss from sale or exchange of pre-1994 property			9	NONE
10 Adjusted current earnings. Combine lines 1, 2c, 3f, 4f, and 5f through 9. Enter the result here and on line 4a of Form 4626			10	-50,692,428.

Form **4136**

Department of the Treasury
Internal Revenue Service (99)

Credit for Federal Tax Paid on Fuels

► Information about Form 4136 and its separate instructions is at *www.irs.gov/form4136.*

OMB No. 1545-0162
2016
Attachment Sequence No. 23

Name (as shown on your income tax return)	Taxpayer identification number
SCANA CORPORATION	57-0784499

Caution: Claimant has the name and address of the person who sold the fuel to the claimant and the dates of purchase. For claims on lines 1c and 2b (type of use 13 or 14), 3d, 4c, and 5, claimant has not waived the right to make the claim. For claims on lines 1c and 2b (type of use 13 or 14), claimant certifies that a certificate has not been provided to the credit card issuer.

1 Nontaxable Use of Gasoline *Note: CRN is credit reference number.*

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Off-highway business use		$ .183	164195		
b	Use on a farm for farming purposes		.183		30,048.	362
c	Other nontaxable use (see Caution above line 1)		.183		$	
d	Exported		.184			411

2 Nontaxable Use of Aviation Gasoline

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use in commercial aviation (other than foreign trade)		$ .15		$	354
b	Other nontaxable use (see Caution above line 1)		.193			324
c	Exported		.194			412
d	LUST tax on aviation fuels used in foreign trade		.001			433

3 Nontaxable Use of Undyed Diesel Fuel

Claimant certifies that the diesel fuel did not contain visible evidence of dye.
Exception. If any of the diesel fuel included in this claim did contain visible evidence of dye, attach an explanation and check here ► ☐

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Nontaxable use		$ .243	137268		
b	Use on a farm for farming purposes		.243		$ 33,356.	360
c	Use in trains		.243			353
d	Use in certain intercity and local buses (see Caution above line 1)		.17			350
e	Exported		.244			413

4 Nontaxable Use of Undyed Kerosene (Other Than Kerosene Used in Aviation)

Claimant certifies that the kerosene did not contain visible evidence of dye.
Exception. If any of the kerosene included in this claim did contain visible evidence of dye, attach an explanation and check here ► ☐

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Nontaxable use taxed at $.244		$ .243			
b	Use on a farm for farming purposes		.243		$	346
c	Use in certain intercity and local buses (see Caution above line 1)		.17			347
d	Exported		.244			414
e	Nontaxable use taxed at $.044		.043			377
f	Nontaxable use taxed at $.219		.218			369

5 Kerosene Used in Aviation (see Caution above line 1)

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Kerosene used in commercial aviation (other than foreign trade) taxed at $.244		$ .200		$	417
b	Kerosene used in commercial aviation (other than foreign trade) taxed at $.219		.175			355
c	Nontaxable use (other than use by state or local government) taxed at $.244		.243			346
d	Nontaxable use (other than use by state or local government) taxed at $.219		.218			369
e	LUST tax on aviation fuels used in foreign trade		.001			433

6 Sales by Registered Ultimate Vendors of Undyed Diesel Fuel Registration No. ▶

Claimant certifies that it sold the diesel fuel at a tax-excluded price, repaid the amount of tax to the buyer, or has obtained the written consent of the buyer to make the claim. Claimant certifies that the diesel fuel did not contain visible evidence of dye.

Exception. If any of the diesel fuel included in this claim did contain visible evidence of dye, attach an explanation and check here ▶ ☐

		(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use by a state or local government	$ .243		$	360
b	Use in certain intercity and local buses	.17			350

7 Sales by Registered Ultimate Vendors of Undyed Kerosene (Other Than Kerosene For Use in Aviation) Registration No. ▶

Claimant certifies that it sold the kerosene at a tax-excluded price, repaid the amount of tax to the buyer, or has obtained the written consent of the buyer to make the claim. Claimant certifies that the kerosene did not contain visible evidence of dye.

Exception. If any of the kerosene included in this claim did contain visible evidence of dye, attach an explanation and check here ▶ ☐

		(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use by a state or local government	$ .243			
b	Sales from a blocked pump	.243		$	346
c	Use in certain intercity and local buses	.17			347

8 Sales by Registered Ultimate Vendors of Kerosene For Use in Aviation Registration No. ▶

Claimant sold the kerosene for use in aviation at a tax-excluded price and has not collected the amount of tax from the buyer, repaid the amount of tax to the buyer, or has obtained the written consent of the buyer to make the claim. See the instructions for additional information to be submitted.

		(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a	Use in commercial aviation (other than foreign trade) taxed at $.219		$ .175		$	355
b	Use in commercial aviation (other than foreign trade) taxed at $.244		.200			417
c	Nonexempt use in noncommercial aviation		.025			418
d	Other nontaxable uses taxed at $.244		.243			346
e	Other nontaxable uses taxed at $.219		.218			369
f	LUST tax on aviation fuels used in foreign trade		.001			433

9 Reserved Registration No. ▶

	(b) Rate	(c) Gallons of alcohol	(d) Amount of credit	(e) CRN
a Reserved				
b Reserved				

10 Biodiesel or Renewable Diesel Mixture Credit Registration No. ▶

Biodiesel mixtures. Claimant produced a mixture by mixing biodiesel with diesel fuel. The biodiesel used to produce the mixture met ASTM D6751 and met EPA's registration requirements for fuels and fuel additives. The mixture was sold by the claimant to any person for use as a fuel or was used as a fuel by the claimant. Claimant has attached the Certificate for Biodiesel and, if applicable, the Statement of Biodiesel Reseller. **Renewable diesel mixtures.** Claimant produced a mixture by mixing renewable diesel with liquid fuel (other than renewable diesel). The renewable diesel used to produce the renewable diesel mixture was derived from biomass process, met EPA's registration requirements for fuels and fuel additives, and met ASTM D975, D396, or other equivalent standard approved by the IRS. The mixture was sold by the claimant to any person for use as a fuel or was used as a fuel by the claimant. Claimant has attached the Certificate for Biodiesel and, if applicable, the Statement of Biodiesel Reseller, both of which have been edited as discussed in the Instructions for Form 4136. See the instructions for line 10 for information about renewable diesel used in aviation.

	(b) Rate	(c) Gallons of biodiesel or renewable diesel	(d) Amount of credit	(e) CRN
a Biodiesel (other than agri-biodiesel) mixtures	$1.00		$	388
b Agri-biodiesel mixtures	$1.00			390
c Renewable diesel mixtures	$1.00			307

11 Nontaxable Use of Alternative Fuel

Caution: There is a reduced credit rate for use in certain intercity and local buses (type of use 5) (see instructions).

	(a) Type of use	(b) Rate	(c) Gallons, or gasoline or diesel gallon equivalents	(d) Amount of credit	(e) CRN
a Liquefied petroleum gas (LPG) (see instructions)		$.183		$	419
b "P Series" fuels		.183			420
c Compressed natural gas (CNG) (see instructions)		.183			421
d Liquefied hydrogen		.183			422
e Fischer-Tropsch process liquid fuel from coal (including peat)		.243			423
f Liquid fuel derived from biomass		.243			424
g Liquefied natural gas (LNG) (see instructions)		.243			425
h Liquefied gas derived from biomass		.183			435

12 Alternative Fuel Credit Registration No. ▶

	(b) Rate	(c) Gallons, or gasoline or diesel gallon equivalents	(d) Amount of credit	(e) CRN
a Liquefied petroleum gas (LPG) (see instructions)	$ .50		$	426
b "P Series" fuels	.50			427
c Compressed natural gas (CNG) (see instructions)	.50	348923	174,462.	428
d Liquefied hydrogen	.50			429
e Fischer-Tropsch process liquid fuel from coal (including peat)	.50			430
f Liquid fuel derived from biomass	.50			431
g Liquefied natural gas (LNG) (see instructions)	.50			432
h Liquefied gas derived from biomass	.50			436
i Compressed gas derived from biomass	.50			437

13 Registered Credit Card Issuers Registration No. ▶

	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a Diesel fuel sold for the exclusive use of a state or local government	$ .243		$	360
b Kerosene sold for the exclusive use of a state or local government	.243			346
c Kerosene for use in aviation sold for the exclusive use of a state or local government taxed at $.219	.218			369

14 Nontaxable Use of a Diesel-Water Fuel Emulsion

Caution: There is a reduced credit rate for use in certain intercity and local buses (type of use 5) (see instructions).

	(a) Type of use	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a Nontaxable use		$ .197		$	309
b Exported		.198			306

15 Diesel-Water Fuel Emulsion Blending Registration No. ▶

	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
Blender credit	$ .046		$	310

16 Exported Dyed Fuels and Exported Gasoline Blendstocks

	(b) Rate	(c) Gallons	(d) Amount of credit	(e) CRN
a Exported dyed diesel fuel and exported gasoline blendstocks taxed at $.001	$ .001		$	415
b Exported dyed kerosene	.001			416

17 **Total income tax credit claimed.** Add lines 1 through 16, column (d). Enter here and on Form 1040, line 72; Form 1120, Schedule J, line 19b; Form 1120S, line 23c; Form 1041, line 24g; or the proper line of other returns. ▶	17	$ 237,866.	

SCHEDULE B (Form 1120)
(Rev. December 2014)
Department of the Treasury
Internal Revenue Service

Additional Information for Schedule M-3 Filers

▶ Attach to Form 1120.
▶ See instructions on page 2.

OMB No. 1545-0123

Name: SCANA CORPORATION
Employer identification number (EIN): 57-0784499

		Yes	No
1	Does any amount reported on Schedule M-3 (Form 1120), Part II, lines 9 or 10, column (d), reflect allocations to this corporation from a partnership of income, gain, loss, deduction, or credit that are disproportionate to this corporation's capital contribution to the partnership or its ratio for sharing other items of the partnership?		X
2	At any time during the tax year, did the corporation sell, exchange, or transfer any interest in an intangible asset to a related person as defined in section 267(b)?	X	
3	At any time during the tax year, did the corporation acquire any interest in an intangible asset from a related person as defined in section 267(b)?	X	
4a	During the tax year, did the corporation enter into a cost-sharing arrangement with any related foreign party on whose behalf the corporation did not file Form 5471, Information Return of U.S. Persons With Respect To Certain Foreign Corporations?		X
b	At any time during the tax year, was the corporation a participant in a cost-sharing arrangement with any related foreign party on whose behalf the corporation did not file Form 5471?		X
5	At any time during the tax year, did the corporation make any change in accounting principle for financial accounting purposes? See instructions for the definition of change in accounting principle		X
6	At any time during the tax year, did the corporation make any change in a method of accounting for U.S. income tax purposes?		X
7	At any time during the tax year, did the corporation own any voluntary employees' beneficiary association (VEBA) trusts that were used to hold funds designated for employee benefits?	X	
8	At any time during the tax year, did the corporation use an allocation method for indirect costs capitalized to self-constructed assets that varied from its financial method of accounting?		X
9	At any time during the tax year, did the corporation treat for tax purposes indirect costs, as defined in Regulations sections 1.263A-1(e)(3)(ii)(F), (G), and (H), as mixed-service costs, as defined in Regulations section 1.263A-1(e)(4)(ii)(C)?	X	
10	Did the corporation, under section 118 or 362(c) and the related regulations, take a return filing position characterizing any amount as a contribution to the capital of the corporation during the tax year by any non-shareholders? Amounts so characterized may include, without limitation, incentives, inducements, money, and property.	X	

Form **851** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Affiliations Schedule

For tax year ending 12/31/2016

▶File with each consolidated income tax return.

▶Information about Form 851 and its instructions is at *www.irs.gov/form851.*

OMB No. 1545-0123

Name of common parent corporation: SCANA CORPORATION

Employer identification number: 57-0784499

Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY

City or town, state, and ZIP code: CAYCE, SC 29033-3701

Part I Overpayment Credits, Estimated Tax Payments, and Tax Deposits (see instructions)

Corp. No.	Name and address of corporation	Employer identification number	Portion of overpayment credits and estimated tax payments	Portion of tax deposited with Form 7004
1	Common parent corporation		6,000,000.	
	Subsidiary corporations:			
2	SCANA SERVICES INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-1092169		
3	SOUTH CAROLINA ELECTRIC and GAS COMPANY 220 OPERATION WAY CAYCE, SC 29033-3701	57-0248695		
4	SOUTH CAROLINA FUEL CO INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0691209		
5	SC GENERATING COMPANY INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0784498		
6	SCANA COMMUNICATIONS HOLDINGS INC 1011 CENTRE ROAD SUITE 322 WILMINGTON, DE 19805	51-0394908		
7	SCANA ENERGY MARKETING INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0850977		
	Totals (Must equal amounts shown on the consolidated tax return.) ▶		6,000,000.	

Part II Principal Business Activity, Voting Stock Information, Etc. (see instructions)

Corp. No.	Principal business activity (PBA)	PBA Code No.	Did the subsidiary make any nondividend distributions? Yes	No	Stock holdings at beginning of year: Number of shares	Percentage of voting power	Percentage of value	Owned by corporation no.
1	Common parent corporation HOLDING COMPANY	551112						
	Subsidiary corporations:							
2	SERVICES	541990		X	1,000	100.00 %	100.00%	1
3	UTILITY	221100		X	40,296,147	100.00 %	100.00%	1
4	WHOLESALE	423520		X	1	100.00 %	100.00%	1
5	Utility	221112		X	1	100.00 %	100.00%	1
6	OTHER INVESTMENT ACTIVITY	523999		X	1	100.00 %	100.00%	1
7	MARKETING	221210		X	1	100.00 %	100.00%	1

Form **851** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Affiliations Schedule

For tax year ending 12/31/2016

▶File with each consolidated income tax return.

▶ Information about Form 851 and its instructions is at *www.irs.gov/form851*.

OMB No. 1545-0123

Name of common parent corporation: SCANA CORPORATION

Employer identification number: 57-0784499

Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY

City or town, state, and ZIP code: CAYCE, SC 29033-3701

Part I **Overpayment Credits, Estimated Tax Payments, and Tax Deposits** (see instructions)

Corp. No.	Name and address of corporation	Employer identification number	Portion of overpayment credits and estimated tax payments	Portion of tax deposited with Form 7004
	Common parent corporation			
	Subsidiary corporations:			
8	SERVICECARE INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-1007394		
9	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 220 OPERATION WAY CAYCE, SC 29033-3701	56-2128483		
10	CLEAN ENERGY ENTERPRISES INC 220 OPERATION WAY CAYCE, SC 29033-3701	56-1078443		
11	PSNC BLUE RIDGE CORPORATION 220 OPERATION WAY CAYCE, SC 29033-3701	56-1791764		
12	PSNC CARDINAL PIPELINE COMPANY 220 OPERATION WAY CAYCE, SC 29033-3701	56-1955423		
13	SCANA CORPORATE SECURITY SERVICES INC 220 OPERATION WAY CAYCE, SC 29033-3701	20-0989017		
	Totals (Must equal amounts shown on the consolidated tax return.) . . . . ▶			

Part II **Principal Business Activity, Voting Stock Information, Etc.** (see instructions)

Corp. No.	Principal business activity (PBA)	PBA Code No.	Did the subsidiary make any nondividend distributions? Yes	No	Stock holdings at beginning of year: Number of shares	Percentage of voting power	Percentage of value	Owned by corporation no.
	Common parent corporation							
	Subsidiary corporations:							
8	SERVICES	811412		X	1,000	100.00 %	100.00%	1
9	NATURAL GAS DISTRIBUTION	221210		X	1,000	100.00 %	100.00%	1
10	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00%	9
11	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00%	9
12	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00%	9
13	SERVICES	541990		X	1,000	100.00 %	100.00%	1

Part III Changes in Stock Holdings During the Tax Year

Corp. No.	Name of corporation	Shareholder of Corporation No.	Date of transaction	(a) Changes: Number of shares acquired	(a) Changes: Number of shares disposed of	(b) Shares held after changes described in column (a): Percentage of voting power	(b) Shares held after changes described in column (a): Percentage of value
8	SERVICECARE INC	1	12/20/2016		1,000	%	%
						%	%
						%	%
						%	%
						%	%
						%	%
						%	%
						%	%

(c) If any transaction listed above caused a transfer of a share of subsidiary stock (defined to include dispositions and deconsolidations), did the share's basis exceed its value at the time of the transfer? See instructions . . . . ☐ Yes ☒ No

(d) Did any share of subsidiary stock become worthless within the meaning of section 165 (taking into account the provisions of Regulations section 1.1502-80(c)) during the taxable year? See instructions . . . . . . ☐ Yes ☒ No

(e) If the equitable owners of any capital stock shown above were other than the holders of record, provide details of the changes.

(f) If additional stock was issued, or if any stock was retired during the year, list the dates and amounts of these transactions.

Part IV Additional Stock Information (see instructions)

1 During the tax year, did the corporation have more than one class of stock outstanding? . . . . [X] Yes [ ] No

If "Yes," enter the name of the corporation and list and describe each class of stock.

Corp. No.	Name of corporation	Class of stock
3	SOUTH CAROLINA ELECTRIC and GAS COMPANY	COMMON AND PREFERRED 1000 SHS

2 During the tax year, was there any member of the consolidated group that reaffiliated within 60 months of disaffiliation? . . . . [ ] Yes [X] No

If "Yes," enter the name of the corporation(s) and explain the circumstances.

Corp. No.	Name of corporation	Explanation

3 During the tax year, was there any arrangement in existence by which one or more persons that were not members of the affiliated group could acquire any stock, or acquire any voting power without acquiring stock, in the corporation, other than a de minimis amount, from the corporation or another member of the affiliated group? . . . . [ ] Yes [X] No

If "Yes," enter the name of the corporation and see the instructions for the percentages to enter in columns (a), (b), and (c).

Corp. No.	Name of corporation	(a) Percentage of value	(b) Percentage of outstanding voting stock	(c) Percentage of voting power
		%	%	%
		%	%	%
		%	%	%
		%	%	%

Corp. No.	(d) Provide a description of any arrangement.

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SCHEDULE D (Form 1120)

Department of the Treasury Internal Revenue Service

Capital Gains and Losses

▶ Attach to Form 1120, 1120-C, 1120-F, 1120-FSC, 1120-H, 1120-IC-DISC, 1120-L, 1120-ND, 1120-PC, 1120-POL, 1120-REIT, 1120-RIC, 1120-SF, or certain Forms 990-T.

▶ Information about Schedule D (Form 1120) and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name: SCANA CORPORATION

Employer identification number: 57-0784499

Part I Short-Term Capital Gains and Losses - Assets Held One Year or Less

See instructions for how to figure the amounts to enter on the lines below. This form may be easier to complete if you round off cents to whole dollars.	(d) Proceeds (sales price)	(e) Cost (or other basis)	(g) Adjustments to gain or loss from Form(s) 8949, Part I, line 2, column (g)	(h) Gain or (loss) Subtract column (e) from column (d) and combine the result with column (g)
1a Totals for all short-term transactions reported on Form 1099-B for which basis was reported to the IRS and for which you have no adjustments (see instructions). However, if you choose to report all these transactions on Form 8949, leave this line blank and go to line 1b				
1b Totals for all transactions reported on Form(s) 8949 with Box A checked				
2 Totals for all transactions reported on Form(s) 8949 with Box B checked				
3 Totals for all transactions reported on Form(s) 8949 with Box C checked	28,933.	33,912.		-4,979.

4 Short-term capital gain from installment sales from Form 6252, line 26 or 37	4	
5 Short-term capital gain or (loss) from like-kind exchanges from Form 8824	5	
6 Unused capital loss carryover (attach computation)	6	( )
7 Net short-term capital gain or (loss). Combine lines 1a through 6 in column h	7	-4,979.

Part II Long-Term Capital Gains and Losses - Assets Held More Than One Year

See instructions for how to figure the amounts to enter on the lines below. This form may be easier to complete if you round off cents to whole dollars.	(d) Proceeds (sales price)	(e) Cost (or other basis)	(g) Adjustments to gain or loss from Form(s) 8949, Part II, line 2, column (g)	(h) Gain or (loss) Subtract column (e) from column (d) and combine the result with column (g)
8a Totals for all long-term transactions reported on Form 1099-B for which basis was reported to the IRS and for which you have no adjustments (see instructions). However, if you choose to report all these transactions on Form 8949, leave this line blank and go to line 8b				
8b Totals for all transactions reported on Form(s) 8949 with Box D checked				
9 Totals for all transactions reported on Form(s) 8949 with Box E checked				
10 Totals for all transactions reported on Form(s) 8949 with Box F checked	1,197,187.	1,119,842.		77,345.

11 Enter gain from Form 4797, line 7 or 9	11	
12 Long-term capital gain from installment sales from Form 6252, line 26 or 37	12	
13 Long-term capital gain or (loss) from like-kind exchanges from Form 8824	13	
14 Capital gain distributions (see instructions) See Statement 49	14	158,428.
15 Net long-term capital gain or (loss). Combine lines 8a through 14 in column h	15	235,773.

Part III Summary of Parts I and II

16 Enter excess of net short-term capital gain (line 7) over net long-term capital loss (line 15)	16	
17 Net capital gain. Enter excess of net long-term capital gain (line 15) over net short-term capital loss (line 7)	17	230,794.
18 Add lines 16 and 17. Enter here and on Form 1120, page 1, line 8, or the proper line on other returns. If the corporation has qualified timber gain, also complete Part IV	18	230,794.

Note: If losses exceed gains, see Capital losses in the instructions.

Form **8949**

Department of the Treasury
Internal Revenue Service

Sales and Other Dispositions of Capital Assets

▶ Information about Form 8949 and its separate instructions is at *www.irs.gov/form8949.*

▶ File with your Schedule D to list your transactions for lines 1b, 2, 3, 8b, 9, and 10 of Schedule D.

OMB No. 1545-0074

2016

Attachment Sequence No. 12A

Name(s) shown on return	Social security number or taxpayer identification number
SCANA CORPORATION	57-0784499

Before you check Box A, B, or C below, see whether you received any Form(s) 1099-B or substitute statement(s) from your broker. A substitute statement will have the same information as Form 1099-B. Either will show whether your basis (usually your cost) was reported to the IRS by your broker and may even tell you which box to check.

Part I **Short-Term.** Transactions involving capital assets you held 1 year or less are short term. For long-term transactions, see page 2.

Note: You may aggregate all short-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS and for which no adjustments or codes are required. Enter the totals directly on Schedule D, line 1a; you aren't required to report these transactions on Form 8949 (see instructions).

You *must* check Box A, B, *or* C below. Check only one box. If more than one box applies for your short-term transactions, complete a separate Form 8949, page 1, for each applicable box. If you have more short-term transactions than will fit on this page for one or more of the boxes, complete as many forms with the same box checked as you need.

- [ ] (A) Short-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS (see Note above)
- [ ] (B) Short-term transactions reported on Form(s) 1099-B showing basis wasn't reported to the IRS
- [x] (C) Short-term transactions not reported to you on Form 1099-B

1 (a) Description of property (Example: 100 sh. XYZ Co.)	(b) Date acquired (Mo., day, yr.)	(c) Date sold or disposed of (Mo., day, yr.)	(d) Proceeds (sales price) (see instructions)	(e) Cost or other basis. See the Note below and see Column (e) in the separate instructions	Adjustment, if any, to gain or loss. If you enter an amount in column (g), enter a code in column (f). See the separate instructions. (f) Code(s) from instructions	(g) Amount of adjustment	(h) Gain or (loss). Subtract column (e) from column (d) and combine the result with column (g)
EDCP SHORT TERM	04/20/2015	01/25/2016	28,933.	33,912.			-4,979.
2 Totals. Add the amounts in columns (d), (e), (g), and (h) (subtract negative amounts). Enter each total here and include on your Schedule D, line 1b (if Box A above is checked), line 2 (if Box B above is checked), or line 3 (if Box C above is checked) ▶			28,933.	33,912.			-4,979.

Note: If you checked Box A above but the basis reported to the IRS was incorrect, enter in column (e) the basis as reported to the IRS, and enter an adjustment in column (g) to correct the basis. See *Column (g)* in the separate instructions for how to figure the amount of the adjustment.

Form 8949 (2016) Attachment Sequence No. 12A Page 2

Name(s) shown on return. Name and SSN or taxpayer identification no. not required if shown on other side	Social security number or taxpayer identification number
SCANA CORPORATION	57-0784499

Before you check Box D, E, or F below, see whether you received any Form(s) 1099-B or substitute statement(s) from your broker. A substitute statement will have the same information as Form 1099-B. Either will show whether your basis (usually your cost) was reported to the IRS by your broker and may even tell you which box to check.

Part II **Long-Term.** Transactions involving capital assets you held more than 1 year are long term. For short-term transactions, see page 1.

Note: You may aggregate all long-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS and for which no adjustments or codes are required. Enter the totals directly on Schedule D, line 8a; you aren't required to report these transactions on Form 8949 (see instructions).

You ***must*** **check Box D, E, *or* F below. Check only one box.** If more than one box applies for your long-term transactions, complete a separate Form 8949, page 2, for each applicable box. If you have more long-term transactions than will fit on this page for one or more of the boxes, complete as many forms with the same box checked as you need.

[ ] (D) Long-term transactions reported on Form(s) 1099-B showing basis was reported to the IRS (see **Note** above)
[ ] (E) Long-term transactions reported on Form(s) 1099-B showing basis **wasn't** reported to the IRS
[x] (F) Long-term transactions not reported to you on Form 1099-B

1 (a) Description of property (Example: 100 sh. XYZ Co.)	(b) Date acquired (Mo., day, yr.)	(c) Date sold or disposed (Mo., day, yr.)	(d) Proceeds (sales price) (see instructions)	(e) Cost or other basis. See the Note below and see *Column (e)* in the separate instructions	Adjustment, if any, to gain or loss. If you enter an amount in column (g), enter a code in column (f). See the separate instructions. (f) Code(s) from instructions	(g) Amount of adjustment	(h) Gain or (loss). Subtract column (e) from column (d) and combine the result with column (g)
EDCP LONG TERM	02/05/2014	01/25/2016	979,243.	901,898.			77,345.
TIMBER SALES	VARIOUS		217,944.	217,944.			NONE
2 Totals. Add the amounts in columns (d), (e), (g), and (h) (subtract negative amounts). Enter each total here and include on your Schedule D, line 8b (if Box D above is checked), line 9 (if Box E above is checked), or line 10 (if Box F above is checked) ▶			1,197,187.	1,119,842.			77,345.

Note: *If you checked Box D above but the basis reported to the IRS was incorrect, enter in column (e) the basis as reported to the IRS, and enter an adjustment in column (g) to correct the basis. See Column (g) in the separate instructions for how to figure the amount of the adjustment.*

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Form **8949** (2016)

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SCHEDULE M-3 (Form 1120)
Department of the Treasury Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ Attach to Form 1120 or 1120-C. ▶ Information about Schedule M-3 (Form 1120) and its separate instructions is available at *www.irs.gov/form1120.*

OMB No. 1545-0123
2016

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Non-consolidated return (2) [X] Consolidated return (Form 1120 only)
(3) [ ] Mixed 1120/L/PC group (4) [ ] Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
[X] **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
[ ] **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
[ ] **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
[ ] **Yes.** Complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 01/01/2016 Ending 12/31/2016

b Has the corporation's income statement been restated for the income statement period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

3 a Is any of the corporation's voting common stock publicly traded?
[X] **Yes.**
[ ] **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock: SCG

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock: 80589M102

Line	Description	Box	Amount
4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	4a	591,551,110.
b	Indicate accounting standard used for line 4a (see instructions): (1) [X] GAAP (2) [ ] IFRS (3) [ ] Statutory (4) [ ] Tax-basis (5) [ ] Other (specify)		
5 a	Net income from nonincludible foreign entities (attach statement)	5a	( )
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount)	5b	
6 a	Net income from nonincludible U.S. entities (attach statement)	6a	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	6b	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	7a	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement)	7b	
c	Net income (loss) of other includible entities (attach statement)	7c	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	8	
9	Adjustment to reconcile income statement period to tax year (attach statement)	9	
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	10a	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	10b	
c	Other adjustments to reconcile to amount on line 11 (attach statement)	10c	
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	11	591,551,110.

Note. *Part I, line 11, must equal Part II, line 30, column (a) or Schedule M-1, line 1 (see instructions).*

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

		Total Assets	Total Liabilities
a	Included on Part I, line 4 ▶		
b	Removed on Part I, line 5 ▶		
c	Removed on Part I, line 6 ▶		
d	Included on Part I, line 7 ▶		

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return) | Employer identification number

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed		34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	-3,486,238.	-1,380,838.		-4,867,076.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	40,230,547.	200,985,885.		241,216,432.
14 Total accrual to cash adjustment				
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(2,169,000,078.)	72,440,739.		(2,096,559,339.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	566,889.	-566,889.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities		235,773.		235,773.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-4,979.		-4,979.
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-51,771,917.		-51,771,917.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement) Stmt 52	4,348,156,767.	24,580,638.	222,694.	4,372,960,099.
26 Total income (loss) items. Combine lines 1 through 25	2,195,097,603.	244,604,783.	222,694.	2,439,925,080.
27 Total expense/deduction items (from Part III, line 38)	-1,612,242,751.	-1,113,798,663.	214,770,120.	-2,511,271,294.
28 Other items with no differences	8,696,258.	Stmt 53		8,696,258.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	591,551,110.	-869,193,880.	214,992,814.	-62,649,956.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	591,551,110.	-869,193,880.	214,992,814.	-62,649,956.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)
Employer identification number

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	33,246,005.		-33,246,005.	
2 U.S. deferred income tax expense	201,820,874.		-201,820,874.	
3 State and local current income tax expense	12,805,324.	-11,240,307.		1,565,017.
4 State and local deferred income tax expense	21,269,254.	-21,269,254.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	342,269,370.	42,908,253.		385,177,623.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	2,833,057.		-1,501,983.	1,331,074.
12 Fines and penalties	-346,594.		346,594.	
13 Judgments, damages, awards, and similar costs	9,343,483.	-2,378,759.		6,964,724.
14 Parachute payments				
15 Compensation with section 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.
16 Pension and profit-sharing	24,499,724.	-23,804,767.		694,957.
17 Other post-retirement benefits	61,069,682.	-4,266,874.		56,802,808.
18 Deferred compensation Stmt 59	4,528,916.	-4,528,916.		
19 Charitable contribution of cash and tangible property	3,083,562.	497,595.	4,582.	3,585,739.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	4,391,015.	7,212,662.		11,603,677.
29 Reserved				
30 Depletion				
31 Depreciation	352,117,080.	322,789,444.		674,906,524.
32 Bad debt expense	10,931,132.	-583,897.		10,347,235.
33 Corporate-owned life insurance premiums	-624,899.		624,899.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs Stmt 59		722,622,385.		722,622,385.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement) Stmt 60	511,355,651.	85,841,098.	26,913,688.	624,110,437.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,612,242,751.	1,113,798,663.	-214,770,120.	2,511,271,294.

Schedule M-3 (Form 1120) 2016 Page **2**

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed		34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations	612,397,274.		-612,397,274.	
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities		-33,798.		-33,798.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	9,922,963.	-1,366,405.		8,556,558.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities		235,773.		235,773.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-4,979.		-4,979.
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	622,320,237.	-831,917.	-612,397,274.	9,091,046.
27 Total expense/deduction items (from Part III, line 38)	-28,096,287.	6,603,298.	-53,237,447.	-74,730,436.
28 Other items with no differences	-136,909.			-136,909.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	594,087,041.	5,771,381.	-665,634,721.	-65,776,299.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	594,087,041.	5,771,381.	-665,634,721.	-65,776,299.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-21,613,000.		21,613,000.	
2 U.S. deferred income tax expense	-3,623,000.		3,623,000.	
3 State and local current income tax expense	-3,261,300.	3,261,300.		
4 State and local deferred income tax expense	-544,700.	544,700.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	54,743,724.	-3,597.		54,740,127.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	170,908.		-170,908.	
12 Fines and penalties	-350,900.		350,900.	
13 Judgments, damages, awards, and similar costs		44,555.		44,555.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	481,120.	-1,983,346.		-1,502,226.
17 Other post-retirement benefits	-49,835.	-2,846,314.		-2,896,149.
18 Deferred compensation	4,528,916.	-4,528,916.		
19 Charitable contribution of cash and tangible property		145.		145.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums	-662,284.		662,284.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	-1,723,362.	-1,091,825.	27,159,171.	24,343,984.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	28,096,287.	-6,603,298.	53,237,447.	74,730,436.

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SCANA SERVICES INC	57-1092169

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	730,796.			730,796.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(74,318,188.)			(74,318,188.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-696,096.		-696,096.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-73,587,392.	-696,096.		-74,283,488.
27 Total expense/deduction items (from Part III, line 38)	-228,778,968.	11,381,801.		-217,397,167.
28 Other items with no differences	302,366,360.			302,366,360.
29a Mixed groups, see instructions. All others, combine lines 26 through 28		10,685,705.		10,685,705.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c		10,685,705.		10,685,705.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA SERVICES INC

Employer identification number: 57-1092169

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	5,064,100.		-5,064,100.	
2 U.S. deferred income tax expense	-5,064,100.		5,064,100.	
3 State and local current income tax expense	848,600.	-838,600.		10,000.
4 State and local deferred income tax expense	-848,600.	848,600.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	9,119,174.			9,119,174.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	5,113,014.	-522,071.		4,590,943.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	364,871.			364,871.
17 Other post-retirement benefits	29,670,928.			29,670,928.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	3,396,707.	-1,257,589.		2,139,118.
29 Reserved				
30 Depletion				
31 Depreciation	12,610,493.	3,229,767.		15,840,260.
32 Bad debt expense	57,907.			57,907.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		882,125.		882,125.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	168,445,874.	-13,724,033.		154,721,841.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	228,778,968.	-11,381,801.		217,397,167.

Schedule M-3 (Form 1120) 2016

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA ELECTRIC and GAS COMPANY
Employer identification number: 57-0248695

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	-3,486,238.	-1,347,040.		-4,833,278.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	32,004,614.	203,397,097.		235,401,711.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(1,104,945,601.)	16,634,798.		(1,088,310,803.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	621,436.	-621,436.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-38,024,208.		-38,024,208.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	2,974,321,805.	24,317,336.	60,389.	2,998,699,530.
26 Total income (loss) items. Combine lines 1 through 25	1,898,516,016.	204,356,547.	60,389.	2,102,932,952.
27 Total expense/deduction items (from Part III, line 38)	-1,155,512,001.	-959,826,350.	212,981,318.	-1,902,357,033.
28 Other items with no differences	-230,312,531.			-230,312,531.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	512,691,484.	-755,469,803.	213,041,707.	-29,736,612.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	512,691,484.	-755,469,803.	213,041,707.	-29,736,612.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA ELECTRIC and GAS COMPANY

Employer identification number: 57-0248695

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	45,571,465.		-45,571,465.	
2 U.S. deferred income tax expense	163,658,014.		-163,658,014.	
3 State and local current income tax expense	11,734,524.	-11,734,524.		
4 State and local deferred income tax expense	19,251,854.	-19,251,854.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	254,693,671.	42,604,735.		297,298,406.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	2,002,874.		-1,001,437.	1,001,437.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	7,729,228.	-1,922,201.		5,807,027.
14 Parachute payments				
15 Compensation with section 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.
16 Pension and profit-sharing	20,973,512.	-19,604,703.		1,368,809.
17 Other post-retirement benefits	44,703,978.	-1,089,215.		43,614,763.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	2,255,999.	478,374.	2,177.	2,736,550.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs		8,116,771.		8,116,771.
29 Reserved				
30 Depletion				
31 Depreciation	268,849,610.	163,071,582.		431,921,192.
32 Bad debt expense	6,625,659.	-275,701.		6,349,958.
33 Corporate owned life insurance premiums	28,544.		-28,544.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		721,608,322.		721,608,322.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	289,782,954.	77,824,764.	-218,753.	367,388,965.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,155,512,001.	959,826,350.	-212,981,318.	1,902,357,033.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION — Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA FUEL CO INC — Employer identification number: 57-0691209

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(235,135,917.)	55,780,868.		(179,355,049.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-235,135,917.	55,780,868.		-179,355,049.
27 Total expense/deduction items (from Part III, line 38)	-1,846,341.	-46,060,920.		-47,907,261.
28 Other items with no differences	236,982,258.			236,982,258.
29a Mixed groups, see instructions. All others, combine lines 26 through 28		9,719,948.		9,719,948.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c		9,719,948.		9,719,948.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA FUEL CO INC

Employer identification number: 57-0691209

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	3,232,500.		-3,232,500.	
2 U.S. deferred income tax expense	-3,232,500.		3,232,500.	
3 State and local current income tax expense	486,100.	-486,100.		
4 State and local deferred income tax expense	-486,100.	486,100.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	1,845,292.			1,845,292.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	11.			11.
17 Other post-retirement benefits	1,038.			1,038.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation		46,060,920.		46,060,920.
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,846,341.	46,060,920.		47,907,261.

Schedule M-3 (Form 1120) 2016

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SC GENERATING COMPANY INC

Employer identification number: 57-0784498

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	54,046.	-31,785.		22,261.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(113,725,200.)			(113,725,200.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-3,530,135.		-3,530,135.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-113,671,154.	-3,561,920.		-117,233,074.
27 Total expense/deduction items (from Part III, line 38)	-55,762,783.	-6,888,802.	6,916,462.	-55,735,123.
28 Other items with no differences	182,523,825.			182,523,825.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	13,089,888.	-10,450,722.	6,916,462.	9,555,628.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	13,089,888.	-10,450,722.	6,916,462.	9,555,628.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SC GENERATING COMPANY INC

Employer identification number: 57-0784498

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	1,526,840.		-1,526,840.	
2 U.S. deferred income tax expense	5,390,460.		-5,390,460.	
3 State and local current income tax expense	344,200.	-344,200.		
4 State and local deferred income tax expense	803,400.	-803,400.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	15,345,851.	-482,617.		14,863,234.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	744.		-372.	372.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	177,603.	20,908.		198,511.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	19,491.			19,491.
17 Other post-retirement benefits	1,568,904.			1,568,904.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	10,012.		2,405.	12,417.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	139,749.	-37,956.		101,793.
29 Reserved				
30 Depletion				
31 Depreciation	18,359,883.	1,230,464.		19,590,347.
32 Bad debt expense				
33 Corporate owned life insurance premiums	1,195.		-1,195.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	12,074,451.	7,305,603.		19,380,054.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	55,762,783.	6,888,802.	-6,916,462.	55,735,123.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA ENERGY MARKETING INC

Employer identification number: 57-0850977

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	374,179.			374,179.
14 Total accrual to cash adjustment				
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(812,053,946.)	-77,007.		(812,130,953.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	1,646.	-1,646.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		1,646.		1,646.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	938,014,128.	263,302.		938,277,430.
26 Total income (loss) items. Combine lines 1 through 25	104,965,723.	-64,826.		104,900,897.
27 Total expense/deduction items (from Part III, line 38)	-49,810,799.	2,042,244.	16,396,483.	-31,372,072.
28 Other items with no differences	-25,341,670.			-25,341,670.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	29,813,254.	1,977,418.	16,396,483.	48,187,155.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	29,813,254.	1,977,418.	16,396,483.	48,187,155.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page **3**

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA ENERGY MARKETING INC

Employer identification number: 57-0850977

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	15,814,300.		-15,814,300.	
2 U.S. deferred income tax expense	382,600.		-382,600.	
3 State and local current income tax expense	2,385,200.	-1,128,598.		1,256,602.
4 State and local deferred income tax expense	32,200.	-32,200.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	1,070,855.			1,070,855.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	384,040.		-192,020.	192,020.
12 Fines and penalties	4,306.		-4,306.	
13 Judgments, damages, awards, and similar costs	77,812.	3,175.		80,987.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	1,007,820.	-954,780.		53,040.
17 Other post-retirement benefits	4,442,895.	-121,580.		4,321,315.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	446,898.	6,536.		453,434.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	854,559.	244,088.		1,098,647.
29 Reserved				
30 Depletion				
31 Depreciation	237,169.	718,134.		955,303.
32 Bad debt expense	3,837,358.	-408,199.		3,429,159.
33 Corporate owned life insurance premiums	3,257.		-3,257.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		131,938.		131,938.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	18,829,530.	-500,758.		18,328,772.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	49,810,799.	-2,042,244.	-16,396,483.	31,372,072.

Schedule M-3 (Form 1120) 2016

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SERVICECARE INC

Employer identification number: 57-1007394

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	5,863.			5,863.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	5,863.			5,863.
27 Total expense/deduction items (from Part III, line 38)	10,393.	-1,168,109.	-8,400.	-1,166,116.
28 Other items with no differences	-31,927.			-31,927.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-15,671.	-1,168,109.	-8,400.	-1,192,180.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	-15,671.	-1,168,109.	-8,400.	-1,192,180.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SERVICECARE INC	57-1007394

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-401,900.		401,900.	
2 U.S. deferred income tax expense	393,500.		-393,500.	
3 State and local current income tax expense	-60,400.	60,400.		
4 State and local deferred income tax expense	59,000.	-59,000.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs		3,709.		3,709.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing		849,150.		849,150.
17 Other post-retirement benefits		313,850.		313,850.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense	-593.			-593.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-10,393.	1,168,109.	8,400.	1,166,116.

Schedule M-3 (Form 1120) 2016

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORTATED

Employer identification number: 56-2128483

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	6,572,645.	-1,013,022.		5,559,623.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(205,178,315.)	102,080.		(205,076,235.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	-56,193.	56,193.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-9,523,124.		-9,523,124.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	435,820,834.		162,305.	435,983,139.
26 Total income (loss) items. Combine lines 1 through 25	237,158,971.	-10,377,873.	162,305.	226,943,403.
27 Total expense/deduction items (from Part III, line 38)	-147,379,356.	-119,881,825.	28,136,365.	-239,124,816.
28 Other items with no differences	-35,495,924.			-35,495,924.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	54,283,691.	-130,259,698.	28,298,670.	-47,677,337.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	54,283,691.	-130,259,698.	28,298,670.	-47,677,337.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORTATED
Employer identification number: 56-2128483

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-15,947,900.		15,947,900.	
2 U.S. deferred income tax expense	43,915,900.		-43,915,900.	
3 State and local current income tax expense	328,400.	-29,985.		298,415.
4 State and local deferred income tax expense	3,002,200.	-3,002,200.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	25,177,074.	789,732.		25,966,806.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	274,491.		-137,246.	137,245.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	1,358,840.	-6,834.		1,352,006.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	2,017,770.	-2,111,088.		-93,318.
17 Other post-retirement benefits	10,402,702.	-523,615.		9,879,087.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	370,653.	12,540.		383,193.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs		147,348.		147,348.
29 Reserved				
30 Depletion				
31 Depreciation	52,059,925.	108,478,577.		160,538,502.
32 Bad debt expense	468,708.	100,003.		568,711.
33 Corporate owned life insurance premiums	4,389.		-4,389.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	23,946,204.	16,027,347.	-26,730.	39,946,821.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	147,379,356.	119,881,825.	-28,136,365.	239,124,816.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
CLEAN ENERGY ENTERPRISES INC	56-1078443

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25				
27 Total expense/deduction items (from Part III, line 38)	400.		-400.	
28 Other items with no differences	-1,703.			-1,703.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-1,303.		-400.	-1,703.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	-1,303.		-400.	-1,703.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
CLEAN ENERGY ENTERPRISES INC	56-1078443

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-400.		400.	
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-400.		400.	

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATE SECURITY SERVICES INC

Employer identification number: 20-0989017

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25				
27 Total expense/deduction items (from Part III, line 38)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28				
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c				

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATE SECURITY SERVICES INC

Employer identification number: 20-0989017

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive				

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [X] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): ELIMINATIONS SCANA CORPORATIO

Employer identification number:

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations	-612,397,274.		612,397,274.	
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	-9,434,559.			-9,434,559.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(-376,357,089.)			(-376,357,089.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-245,474,744.		612,397,274.	366,922,530.
27 Total expense/deduction items (from Part III, line 38)	54,932,991.			54,932,991.
28 Other items with no differences	-421,855,521.			-421,855,521.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-612,397,274.		612,397,274.	
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	-612,397,274.		612,397,274.	

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [X] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
ELIMINATIONS SCANA CORPORATIO	

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	-19,726,271.			-19,726,271.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	-5,113,014.			-5,113,014.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	-364,871.			-364,871.
17 Other post-retirement benefits	-29,670,928.			-29,670,928.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense	-57,907.			-57,907.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-54,932,991.			-54,932,991.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): Adjustments

Employer identification number:

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25				
27 Total expense/deduction items (from Part III, line 38)			3,585,739.	3,585,739.
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28			3,585,739.	3,585,739.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c			3,585,739.	3,585,739.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): Adjustments

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive			-3,585,739.	-3,585,739.

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SCHEDULE UTP (Form 1120)
Department of the Treasury Internal Revenue Service

Uncertain Tax Position Statement

▶ File with Form 1120, 1120-F, 1120-L, or 1120-PC.
▶ Information about Schedule UTP (Form 1120) and its separate instructions is at www.irs.gov/scheduleutp.

OMB No. 1545-0123
2016

Name of entity as shown on page 1 of tax return: SCANA CORPORATION
EIN of entity: 57-0784499

This Part I, Schedule UTP (Form 1120) is page 1 of 1 Part I pages.

Part I **Uncertain Tax Positions for the Current Tax Year.** See instructions for how to complete columns (a) through (g). Enter, in Part III, a description for each uncertain tax position (UTP).

Check this box if the corporation was unable to obtain information from related parties sufficient to determine whether a tax position is a UTP. See instructions. ▶ ☐

(a) UTP No.	(b) Primary IRC Sections (for example, "61", "108", "263A") / Primary IRC Subsections (for example, (f)(2)(A)(ii))			(c) Timing Codes (check if Permanent, Temporary, or both)		(d) Pass-Through Entity EIN	(e) Major Tax Position	(f) Ranking of Tax Position	(g) Reserved for Future Use
C1	41(a)			P ☒	T ☐		☒	G2	
C2	174			P ☐	T ☒		☒	G1	
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		
C				P ☐	T ☐		☐		

Schedule UTP (Form 1120) 2016 Page **2**

Name of entity as shown on page 1 of tax return	EIN of entity
SCANA CORPORATION	57-0784499

This Part II, Schedule UTP (Form 1120) is page 1 of 1 Part II pages.

Part II **Uncertain Tax Positions for Prior Tax Years.**
See instructions for how to complete columns (a) through (h). Enter, in Part III, a description for each uncertain tax position (UTP).

Check this box if the corporation was unable to obtain information from related parties sufficient to determine whether a tax position is a UTP. See instructions. ▶ ☐

(a) UTP No.	(b) Primary IRC Sections (for example, "61", "108", "263A") / Primary IRC Subsections (for example, (f)(2)(A)(ii))			(c) Timing Codes (check if Permanent, Temporary, or both)		(d) Pass-Through Entity EIN	(e) Major Tax Position	(f) Ranking of Tax Position	(g) Reserved for Future Use	(h) Year of Tax Position
P3	41(a)			P ☒	T ☐		☒	G4		2015-12
P4	41(a)			P ☒	T ☐		☒	G4		2014-12
P5	41(a)			P ☒	T ☐		☒	G4		2013-12
P6	41(a)			P ☒	T ☐		☒	G4		2012-12
P7	41(a)			P ☒	T ☐		☒	G4		2011-12
P8	41(a)			P ☒	T ☐		☒	G4		2010-12
P9	41(a)			P ☒	T ☐		☒	G4		2009-12
P10	41(a)			P ☒	T ☐		☒	G4		2008-12
P11	174			P ☐	T ☒		☒	G3		2015-12
P12	174			P ☐	T ☒		☒	G3		2014-12
P13	174			P ☐	T ☒		☒	G3		2013-12
P14	174			P ☐	T ☒		☒	G3		2012-12
P15	174			P ☐	T ☒		☒	G3		2011-12
P16	174			P ☐	T ☒		☒	G3		2010-12
P17	174			P ☐	T ☒		☒	G3		2009-12
P18	174			P ☐	T ☒		☒	G3		2008-12
P				P ☐	T ☐		☐			
P				P ☐	T ☐		☐			
P				P ☐	T ☐		☐			
P				P ☐	T ☐		☐			
P				P ☐	T ☐		☐			

Name of entity as shown on page 1 of tax return: SCANA CORPORATION

EIN of entity: 57-0784499

This Part III, Schedule UTP (Form 1120) is page 1 of 3 Part III pages.

Part III **Concise Descriptions of UTPs.** Indicate the corresponding UTP number from Part I, column (a) (for example, C1) or Part II column (a) (for example, P2). Use as many Part III pages as necessary. See instructions.

UTP No.	Concise Description of Uncertain Tax Position
C1	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
C2	The taxpayer claimed deductions for research expenses related to its nuclear facility. The issues are whether adequate documentation has been retained to substantiate the deductions claimed and whether the expenses constitute research expenses. This position is based on the final regulations as issued under Treasury Regulation Sec 1.174-2.
P3	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
P4	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
P5	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation expenditures in Treasury Regulation Sec 1.174-2 including consideration of the nuclear facility as a pilot model.
P6	The taxpayer incurred costs that were characterized amongst various research activities concerning its nuclear facility based upon a methodology the taxpayer considers reasonable and claimed Sec 41 credits related to these costs. The issues are whether the taxpayer's method of characterizing these costs is acceptable and whether the activities were research. This position is based on the definition of increasing research and experimentation

Name of entity as shown on page 1 of tax return: SCANA CORPORATION

EIN of entity: 57-0784499

This Part III, Schedule UTP (Form 1120) is page 2 of 3 Part III pages.

Part III **Concise Descriptions of UTPs.** Indicate the corresponding UTP number from Part I, column (a) (for example, C1) or Part II column (a) (for example, P2). Use as many Part III pages as necessary. See instructions.

UTP No.	Concise Description of Uncertain Tax Position
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P7	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P8	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P9	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P10	The taxpayer incurred costs that were characterized amongst
	various research activities concerning its nuclear facility based
	upon a methodology the taxpayer considers reasonable and claimed
	Sec 41 credits related to these costs. The issues are whether the
	taxpayer's method of characterizing these costs is acceptable and
	whether the activities were research. This position is based on
	the definition of increasing research and experimentation
	expenditures in Treasury Regulation Sec 1.174-2 including
	consideration of the nuclear facility as a pilot model.
P11	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P12	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under

Name of entity as shown on page 1 of tax return: SCANA CORPORATION

EIN of entity: 57-0784499

This Part III, Schedule UTP (Form 1120) is page 3 of 3 Part III pages.

Part III **Concise Descriptions of UTPs.** Indicate the corresponding UTP number from Part I, column (a) (for example, C1) or Part II column (a) (for example, P2). Use as many Part III pages as necessary. See instructions.

UTP No.	Concise Description of Uncertain Tax Position
	Treasury Regulation Sec 1.174-2.
P13	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P14	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P15	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P16	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P17	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.
P18	The taxpayer claimed deductions for research expenses related to
	its nuclear facility. The issues are whether adequate
	documentation has been retained to substantiate the deductions
	claimed and whether the expenses constitute research expenses.
	This position is based on the final regulations as issued under
	Treasury Regulation Sec 1.174-2.

Form **966** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Corporate Dissolution or Liquidation

(Required under section 6043(a) of the Internal Revenue Code)
▶ Information about Form 966 and its instructions is at *www.irs.gov/form966*.

OMB No. 1545-0123

Please type or print: Name of corporation: SERVICECARE INC			Employer identification number: 57-1007394
Number, street, and room or suite no. (If a P.O. box number, see instructions.): 220 OPERATION WAY			Check type of return: [X] 1120 [ ] 1120-L [ ] 1120-IC-DISC [ ] 1120S [ ] Other ▶
City or town, state, and ZIP code: CAYCE SC 29033-3701			
1 Date incorporated: 09/20/1994	2 Place incorporated: SOUTH CAROLINA	3 Type of liquidation: [X] Complete [ ] Partial	4 Date resolution or plan of complete or partial liquidation was adopted: 12/20/2016
5 Service Center where corporation filed its immediately preceding tax return: efile	6 Last month, day, and year of immediately preceding tax year: 12/31/2015	7a Last month, day, and year of final tax year: 12/31/2016	7b Was corporation's final tax return filed as part of a consolidated income tax return? If "Yes," complete 7c, 7d, and 7e. [X] Yes [ ] No
7c Name of common parent: SCANA CORPORATION		7d Employer identification number of common parent: 57-0784499	7e Service Center where consolidated return was filed: efile

	Common	Preferred
8 Total number of shares outstanding at time of adoption of plan of liquidation	1,000.	
9 Date(s) of any amendments to plan of dissolution		
10 Section of the Code under which the corporation is to be dissolved or liquidated	332	
11 If this form concerns an amendment or supplement to a resolution or plan, enter the date the previous Form 966 was filed		

Attach a certified copy of the resolution or plan and all amendments or supplements not previously filed.

Under penalties of perjury, I declare that I have examined this form, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete.

▶ Signature of officer | CONTROLLER Title | Date

Instructions

Section references are to the Internal Revenue Code unless otherwise noted.

Who Must File

A corporation (or a farmer's cooperative) must file Form 966 if it adopts a resolution or plan to dissolve the corporation or liquidate any of its stock.

Exempt organizations and qualified subchapter S subsidiaries should *not* file Form 966. Exempt organizations should see the instructions for Form 990, Return of Organization Exempt From Income Tax, or Form 990-PF, Return of Private Foundation or Section 4947(a)(1) Trust Treated as Private Foundation. Subchapter S subsidiaries should see Form 8869, Qualified Subchapter S Subsidiary Election.

! CAUTION *Do not file Form 966 for a deemed liquidation (such as a section 338 election or an election to be treated as a disregarded entity under Regulations section 301.7701-3).*

When To File

File Form 966 within 30 days after the resolution or plan is adopted to dissolve the corporation or liquidate any of its stock. If the resolution or plan is amended or supplemented after Form 966 is filed, file another Form 966 within 30 days after the amendment or supplement is adopted. The additional form will be sufficient if the date the earlier form was filed is entered on line 11 and a certified copy of the amendment or supplement is attached. Include all information required by Form 966 that was not given in the earlier form.

Where To File

File Form 966 with the Internal Revenue Service Center at the address where the corporation (or cooperative) files its income tax return.

Distribution of Property

A corporation must recognize gain or loss on the distribution of its assets in the complete liquidation of its stock. For purposes of determining gain or loss, the

Form **1125-A**
(Rev. October 2016)
Department of the Treasury
Internal Revenue Service

Cost of Goods Sold

▶ Attach to Form 1120, 1120-C, 1120-F, 1120S, 1065, or 1065-B.
▶ Information about Form 1125-A and its instructions is at *www.irs.gov/form1125a*.

OMB No. 1545-0123

Name	Employer identification number
SCANA CORPORATION	57-0784499

1	Inventory at beginning of year	1	311,778,910.
2	Purchases	2	730,665,983.
3	Cost of labor	3	-429,280.
4	Additional section 263A costs (attach schedule)	4	
5	Other costs (attach schedule) See. Statement. 66.	5	1,366,645,976.
6	**Total.** Add lines 1 through 5	6	2,408,661,589.
7	Inventory at end of year	7	290,480,845.
8	**Cost of goods sold.** Subtract line 7 from line 6. Enter here and on Form 1120, page 1, line 2 or the appropriate line of your tax return. See instructions	8	2,118,180,744.

9a Check all methods used for valuing closing inventory:
(i) ☐ Cost
(ii) ☐ Lower of cost or market
(iii) ☒ Other (Specify method used and attach explanation.) ▶

b Check if there was a writedown of subnormal goods ▶ ☐

c Check if the LIFO inventory method was adopted this tax year for any goods (if checked, attach Form 970) ▶ ☐

d If the LIFO inventory method was used for this tax year, enter amount of closing inventory computed under LIFO | 9d |

e If property is produced or acquired for resale, do the rules of section 263A apply to the entity? See instructions ☐ Yes ☒ No

f Was there any change in determining quantities, cost, or valuations between opening and closing inventory? If "Yes," attach explanation ☐ Yes ☒ No

Section references are to the Internal Revenue Code unless otherwise noted.

General Instructions

Purpose of Form

Use Form 1125-A to calculate and deduct cost of goods sold for certain entities.

Who Must File

Filers of Form 1120, 1120-C, 1120-F, 1120S, 1065, or 1065-B, must complete and attach Form 1125-A if the applicable entity reports a deduction for cost of goods sold.

Inventories

Generally, inventories are required at the beginning and end of each tax year if the production, purchase, or sale of merchandise is an income-producing factor. See Regulations section 1.471-1. If inventories are required, you generally must use an accrual method of accounting for sales and purchases of inventory items.

Exception for certain taxpayers. If you are a qualifying taxpayer or a qualifying small business taxpayer (defined below), you can adopt or change your accounting method to account for inventoriable items in the same manner as materials and supplies that are not incidental.

Under this accounting method, inventory costs for raw materials purchased for use in producing finished goods and merchandise purchased for resale are deductible in the year the finished goods or merchandise are sold (but not before the year you paid for the raw materials or merchandise, if you are also using the cash method).

If you account for inventoriable items in the same manner as materials and supplies that are not incidental, you can currently deduct expenditures for direct labor and all indirect costs that would otherwise be included in inventory costs. See the instructions for lines 2 and 7.

For additional guidance on this method of accounting, see Pub. 538, Accounting Periods and Methods. For guidance on adopting or changing to this method of accounting, see Form 3115, Application for Change in Accounting Method, and its instructions.

Qualifying taxpayer. A qualifying taxpayer is a taxpayer that, (a) for each prior tax year ending after December 16, 1998, has average annual gross receipts of $1 million or less for the 3 prior tax years, and (b) its business is not a tax shelter (as defined in section 448(d)(3)). See Rev. Proc. 2001-10, 2001-2 I.R.B. 272.

Qualifying small business taxpayer. A qualifying small business taxpayer is a taxpayer that, (a) for each prior tax year ending on or after December 31, 2000, has average annual gross receipts of $10 million or less for the 3 prior tax years, (b) whose principal business activity is not an ineligible activity, and (c) whose business is not a tax shelter (as defined in section 448 (d)(3)). See Rev. Proc. 2002-28, 2002-18 I.R.B. 815.

Uniform capitalization rules. The uniform capitalization rules of section 263A generally require you to capitalize, or include in inventory, certain costs incurred in connection with the following.

- The production of real property and tangible personal property held in inventory or held for sale in the ordinary course of business.
- Real property or personal property (tangible and intangible) acquired for resale.
- The production of real property and tangible personal property by a corporation for use in its trade or business or in an activity engaged in for profit.

See the discussion on section 263A uniform capitalization rules in the *instructions for your tax return* before completing Form 1125-A. Also see Regulations sections 1.263A-1 through 1.263A-3. See Regulations section 1.263A-4 for rules for property produced in a farming business.

Form **1125-E**
(Rev. October 2016)
Department of the Treasury
Internal Revenue Service

Compensation of Officers

▶ Attach to Form 1120, 1120-C, 1120-F, 1120-REIT, 1120-RIC, or 1120S.
▶ Information about Form 1125-E and its separate instructions is at *www.irs.gov/form1125e*.

OMB No. 1545-0123

Name: SCANA CORPORATION

Employer identification number: 57-0784499

Note: Complete Form 1125-E only if total receipts are $500,000 or more. See instructions for definition of total receipts.

(a) Name of officer	(b) Social security number (see instructions)	(c) Percent of time devoted to business	Percent of stock owned (d) Common	(e) Preferred	(f) Amount of compensation
1		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	
		%	%	%	

2 Total compensation of officers	2	15,144,833.
3 Compensation of officers claimed on Form 1125-A or elsewhere on return	3	
4 Subtract line 3 from line 2. Enter the result here and on Form 1120, page 1, line 12 or the appropriate line of your tax return . . . See Statement 68	4	15,144,833.

Form **3800** Department of the Treasury Internal Revenue Service (99)

General Business Credit

▶ Information about Form 3800 and its separate instructions is at *www.irs.gov/form3800*.
▶ You must attach all pages of Form 3800, pages 1, 2, and 3, to your tax return.

OMB No. 1545-0895 **2016** Attachment Sequence No. 22

Name(s) shown on return: SCANA CORPORATION | Identifying number: 57-0784499

Part I Current Year Credit for Credits Not Allowed Against Tentative Minimum Tax (TMT) (See instructions and complete Part(s) III before Parts I and II)

1	General business credit from line 2 of all Parts III with box A checked	1	28,148,334.
2	Passive activity credits from line 2 of all Parts III with box B checked [2]		
3	Enter the applicable passive activity credits allowed for 2016 (see instructions)	3	
4	Carryforward of general business credit to 2016. Enter the amount from line 2 of Part III with box C checked. See instructions for statement to attach	4	
5	Carryback of general business credit from 2017. Enter the amount from line 2 of Part III with box D checked (see instructions)	5	
6	Add lines 1, 3, 4, and 5	6	28,148,334.

Part II Allowable Credit

7	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46, or the sum of the amounts from Form 1040NR, lines 42 and 44 • Corporations. Enter the amount from Form 1120, Schedule J, Part I, line 2; or the applicable line of your return • Estates and trusts. Enter the sum of the amounts from Form 1041, Schedule G, lines 1a and 1b; or the amount from the applicable line of your return	7	
8	Alternative minimum tax: • Individuals. Enter the amount from Form 6251, line 35 • Corporations. Enter the amount from Form 4626, line 14 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 56	8	
9	Add lines 7 and 8	9	
10a	Foreign tax credit [10a]		
b	Certain allowable credits (see instructions) [10b]		
c	Add lines 10a and 10b	10c	
11	**Net income tax.** Subtract line 10c from line 9. If zero, skip lines 12 through 15 and enter -0- on line 16	11	
12	**Net regular tax.** Subtract line 10c from line 7. If zero or less, enter -0- [12]		
13	Enter 25% (.25) of the excess, if any, of line 12 over $25,000 (see instructions) [13]		
14	Tentative minimum tax: • Individuals. Enter the amount from Form 6251, line 33 • Corporations. Enter the amount from Form 4626, line 12 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 54 [14]		
15	Enter the greater of line 13 or line 14	15	
16	Subtract line 15 from line 11. If zero or less, enter -0-	16	
17	Enter the **smaller** of line 6 or line 16 **C corporations:** See the line 17 instructions if there has been an ownership change, acquisition, or reorganization.	17	

Form 3800 (2016) SCANA CORPORATION 57-0784499 Page 2

Part II **Allowable Credit** *(Continued)*

Note: If you are not required to report any amounts on lines 22 or 24 below, skip lines 18 through 25 and enter -0- on line 26.

18	Multiply line 14 by 75% (.75) (see instructions)	18	
19	Enter the greater of line 13 or line 18	19	
20	Subtract line 19 from line 11. If zero or less, enter -0-	20	
21	Subtract line 17 from line 20. If zero or less, enter -0-	21	
22	Combine the amounts from line 3 of all Parts III with box A, C, or D checked	22	
23	Passive activity credit from line 3 of all Parts III with box B checked [23]		
24	Enter the applicable passive activity credit allowed for 2016 (see instructions)	24	
25	Add lines 22 and 24	25	
26	Empowerment zone and renewal community employment credit allowed. Enter the smaller of line 21 or line 25	26	
27	Subtract line 13 from line 11. If zero or less, enter -0-	27	
28	Add lines 17 and 26	28	
29	Subtract line 28 from line 27. If zero or less, enter -0-	29	
30	Enter the general business credit from line 5 of all Parts III with box A checked	30	8,254,946.
31	Reserved	31	
32	Passive activity credits from line 5 of all Parts III with box B checked [32]		
33	Enter the applicable passive activity credits allowed for 2016 (see instructions)	33	
34	Carryforward of business credit to 2016. Enter the amount from line 5 of Part III with box C checked and line 6 of Part III with box G checked. See instructions for statement to attach	34	
35	Carryback of business credit from 2017. Enter the amount from line 5 of Part III with box D checked (see instructions)	35	
36	Add lines 30, 33, 34, and 35	36	8,254,946.
37	Enter the smaller of line 29 or line 36	37	
38	**Credit allowed for the current year.** Add lines 28 and 37. Report the amount from line 38 (if smaller than the sum of Part I, line 6, and Part II, lines 25 and 36, see instructions) as indicated below or on the applicable line of your return: • Individuals. Form 1040, line 54, or Form 1040NR, line 51 • Corporations. Form 1120, Schedule J, Part I, line 5c • Estates and trusts. Form 1041, Schedule G, line 2b	38	

Form 3800 (2016) Page 3

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part III **General Business Credits or Eligible Small Business Credits** (see instructions)

Complete a separate Part III for each box checked below (see instructions).

A	[X]	General Business Credit From a Non-Passive Activity	E	[ ]	Reserved
B	[ ]	General Business Credit From a Passive Activity	F	[ ]	Reserved
C	[ ]	General Business Credit Carryforwards	G	[ ]	Eligible Small Business Credit Carryforwards
D	[ ]	General Business Credit Carrybacks	H	[ ]	Reserved

I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III ▶ [ ]

(a) Description of credit **Note:** On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b Reserved	1b		
c Increasing research activities (Form 6765)	1c		28,145,407.
d Low-income housing (Form 8586, Part I only)	1d		
e Disabled access (Form 8826) (see instructions for limitation)	1e		
f Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g Indian employment (Form 8845)	1g		
h Orphan drug (Form 8820)	1h		
i New markets (Form 8874)	1i		
j Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m Low sulfur diesel fuel production (Form 8896)	1m		
n Distilled spirits (Form 8906)	1n		
o Nonconventional source fuel (carryforward only)	1o		
p Energy efficient home (Form 8908)	1p		
q Energy efficient appliance (carryforward only)	1q		
r Alternative motor vehicle (Form 8910)	1r		
s Alternative fuel vehicle refueling property (Form 8911)	1s		2,927.
t Reserved	1t		
u Mine rescue team training (Form 8923)	1u		
v Agricultural chemicals security (carryforward only)	1v		
w Employer differential wage payments (Form 8932)	1w		
x Carbon dioxide sequestration (Form 8933)	1x		
y Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z Qualified plug-in electric vehicle (carryforward only)	1z		
aa New hire retention (carryforward only)	1aa		
bb General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz Other. Enhanced oil recovery (Form 8830) and certain other credits	1zz		
2 Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		28,148,334.
3 Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a Investment (Form 3468, Part III) (attach Form 3468)	4a		
b Work opportunity (Form 5884)	4b		
c Biofuel producer (Form 6478)	4c		
d Low-income housing (Form 8586, Part II)	4d		
e Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		8,254,946.
f Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g Qualified railroad track maintenance (Form 8900)	4g		
h Small employer health insurance premiums (Form 8941)	4h		
i Increasing research activities (Form 6765)	4i		
j Reserved	4j		
z Other	4z		
5 Add lines 4a through 4z and enter here and on the applicable line of Part II	5		8,254,946.
6 Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		36,403,280.

Form **4562** | **Depreciation and Amortization** (Including Information on Listed Property) ▶ Attach to your tax return. ▶ Information about Form 4562 and its separate instructions is at www.irs.gov/form4562. | OMB No. 1545-0172 **2016** Attachment Sequence No. 179

Department of the Treasury Internal Revenue Service (99)

Name(s) shown on return: SCANA CORPORATION | Identifying number: 57-0784499

Business or activity to which this form relates: General Depreciation & Amortization

Part I Election To Expense Certain Property Under Section 179

Note: If you have any listed property, complete Part V before you complete Part I.

1	Maximum amount (see instructions)	1	
2	Total cost of section 179 property placed in service (see instructions)	2	
3	Threshold cost of section 179 property before reduction in limitation (see instructions)	3	
4	Reduction in limitation. Subtract line 3 from line 2. If zero or less, enter -0-	4	
5	Dollar limitation for tax year. Subtract line 4 from line 1. If zero or less, enter -0-. If married filing separately, see instructions	5	

6 (a) Description of property	(b) Cost (business use only)	(c) Elected cost
7 Listed property. Enter the amount from line 29	7	

8	Total elected cost of section 179 property. Add amounts in column (c), lines 6 and 7	8	
9	Tentative deduction. Enter the smaller of line 5 or line 8	9	
10	Carryover of disallowed deduction from line 13 of your 2015 Form 4562	10	
11	Business income limitation. Enter the smaller of business income (not less than zero) or line 5 (see instructions)	11	
12	Section 179 expense deduction. Add lines 9 and 10, but don't enter more than line 11	12	
13	Carryover of disallowed deduction to 2017. Add lines 9 and 10, less line 12 ▶	13	

Note: Don't use Part II or Part III below for listed property. Instead, use Part V.

Part II Special Depreciation Allowance and Other Depreciation (Don't include listed property.) (See instructions.)

14	Special depreciation allowance for qualified property (other than listed property) placed in service during the tax year (see instructions)	14	309,573,587.
15	Property subject to section 168(f)(1) election	15	
16	Other depreciation (including ACRS)	16	2,616,055.

Part III MACRS Depreciation (Don't include listed property.) (See instructions.)

Section A

17	MACRS deductions for assets placed in service in tax years beginning before 2016	17	347,024,206.
18	If you are electing to group any assets placed in service during the tax year into one or more general asset accounts, check here ▶ ☐		

Section B - Assets Placed in Service During 2016 Tax Year Using the General Depreciation System

(a) Classification of property	(b) Month and year placed in service	(c) Basis for depreciation (business/investment use only - see instructions)	(d) Recovery period	(e) Convention	(f) Method	(g) Depreciation deduction
19a 3-year property						
b 5-year property		9,822,207.	5.000	HY	200 DB	1,964,443.
c 7-year property		13,156,047.	7.000	HY	200 DB	1,879,486.
d 10-year property						
e 15-year property		126,315,695.	15.000	HY	150 DB	6,315,785.
f 20-year property		147,377,601.	20.000	HY	150 DB	5,527,192.
g 25-year property			25 yrs.		S/L	
h Residential rental property			27.5 yrs.	MM	S/L	
			27.5 yrs.	MM	S/L	
i Nonresidential real property		450,159.	39 yrs.	MM	S/L	5,770.
				MM	S/L	

Section C - Assets Placed in Service During 2016 Tax Year Using the Alternative Depreciation System

(a) Classification of property	(b)	(c)	(d)	(e)	(f)	(g)
20a Class life					S/L	
b 12-year			12 yrs.		S/L	
c 40-year			40 yrs.	MM	S/L	

Part IV Summary (See instructions.)

21	Listed property. Enter amount from line 28	21	
22	Total. Add amounts from line 12, lines 14 through 17, lines 19 and 20 in column (g), and line 21. Enter here and on the appropriate lines of your return. Partnerships and S corporations - see instructions	22	674,906,524.
23	For assets shown above and placed in service during the current year, enter the portion of the basis attributable to section 263A costs	23	

SCANA CORPORATION 57-0784499
Form 4562 (2016) Page 2

Part V **Listed Property** (Include automobiles, certain other vehicles, certain aircraft, certain computers, and property used for entertainment, recreation, or amusement.)
Note: For any vehicle for which you are using the standard mileage rate or deducting lease expense, complete only 24a, 24b, columns (a) through (c) of Section A, all of Section B, and Section C if applicable.

Section A - Depreciation and Other Information (Caution: See the instructions for limits for passenger automobiles.)

24a Do you have evidence to support the business/investment use claimed? Yes No 24b If "Yes," is the evidence written? Yes No

(a) Type of property (list vehicles first)	(b) Date placed in service	(c) Business/investment use percentage	(d) Cost or other basis	(e) Basis for depreciation (business/investment use only)	(f) Recovery period	(g) Method/Convention	(h) Depreciation deduction	(i) Elected section 179 cost
25 Special depreciation allowance for qualified listed property placed in service during the tax year and used more than 50% in a qualified business use (see instructions)						25		
26 Property used more than 50% in a qualified business use:								
		%						
		%						
		%						
27 Property used 50% or less in a qualified business use:								
		%				S/L -		
		%				S/L -		
		%				S/L -		
28 Add amounts in column (h), lines 25 through 27. Enter here and on line 21, page 1						28		
29 Add amounts in column (i), line 26. Enter here and on line 7, page 1							29	

Section B - Information on Use of Vehicles

Complete this section for vehicles used by a sole proprietor, partner, or other "more than 5% owner," or related person. If you provided vehicles to your employees, first answer the questions in Section C to see if you meet an exception to completing this section for those vehicles.

	(a) Vehicle 1		(b) Vehicle 2		(c) Vehicle 3		(d) Vehicle 4		(e) Vehicle 5		(f) Vehicle 6	
30 Total business/investment miles driven during the year (don't include commuting miles)												
31 Total commuting miles driven during the year												
32 Total other personal (noncommuting) miles driven												
33 Total miles driven during the year. Add lines 30 through 32												
	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
34 Was the vehicle available for personal use during off-duty hours?												
35 Was the vehicle used primarily by a more than 5% owner or related person?												
36 Is another vehicle available for personal use?												

Section C - Questions for Employers Who Provide Vehicles for Use by Their Employees

Answer these questions to determine if you meet an exception to completing Section B for vehicles used by employees who aren't more than 5% owners or related persons (see instructions).

	Yes	No
37 Do you maintain a written policy statement that prohibits all personal use of vehicles, including commuting, by your employees?		
38 Do you maintain a written policy statement that prohibits personal use of vehicles, except commuting, by your employees? See the instructions for vehicles used by corporate officers, directors, or 1% or more owners		
39 Do you treat all use of vehicles by employees as personal use?		
40 Do you provide more than five vehicles to your employees, obtain information from your employees about the use of the vehicles, and retain the information received?		
41 Do you meet the requirements concerning qualified automobile demonstration use? (See instructions.)		

Note: If your answer to 37, 38, 39, 40, or 41 is "Yes," don't complete Section B for the covered vehicles.

Part VI **Amortization**

(a) Description of costs	(b) Date amortization begins	(c) Amortizable amount	(d) Code section	(e) Amortization period or percentage	(f) Amortization for this year
42 Amortization of costs that begins during your 2016 tax year (see instructions):					
				Total	2,067,441.
43 Amortization of costs that began before your 2016 tax year				43	9,536,236.
44 Total. Add amounts in column (f). See the instructions for where to report				44	11,603,677.

Form **4797**

Department of the Treasury
Internal Revenue Service

Sales of Business Property

(Also Involuntary Conversions and Recapture Amounts Under Sections 179 and 280F(b)(2))

▶ Attach to your tax return.

▶ Information about Form 4797 and its separate instructions is at *www.irs.gov/form4797*.

OMB No. 1545-0184

2016

Attachment Sequence No. 27

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

1 Enter the gross proceeds from sales or exchanges reported to you for 2016 on Form(s) 1099-B or 1099-S (or substitute statement) that you are including on line 2, 10, or 20. See instructions **1**

Part I **Sales or Exchanges of Property Used in a Trade or Business and Involuntary Conversions From Other Than Casualty or Theft - Most Property Held More Than 1 Year** (see instructions)

2 (a) Description of property	(b) Date acquired (mo., day, yr.)	(c) Date sold (mo., day, yr.)	(d) Gross sales price	(e) Depreciation allowed or allowable since acquisition	(f) Cost or other basis, plus improvements and expense of sale	(g) Gain or (loss) Subtract (f) from the sum of (d) and (e)
Stmt 75						-53,778,949.

	Line	Amount
3 Gain, if any, from Form 4684, line 39	3	
4 Section 1231 gain from installment sales from Form 6252, line 26 or 37	4	
5 Section 1231 gain or (loss) from like-kind exchanges from Form 8824	5	
6 Gain, if any, from line 32, from other than casualty or theft	6	
7 Combine lines 2 through 6. Enter the gain or (loss) here and on the appropriate line as follows:	7	-53,778,949.

Partnerships (except electing large partnerships) and S corporations. Report the gain or (loss) following the instructions for Form 1065, Schedule K, line 10, or Form 1120S, Schedule K, line 9. Skip lines 8, 9, 11, and 12 below.

Individuals, partners, S corporation shareholders, and all others. If line 7 is zero or a loss, enter the amount from line 7 on line 11 below and skip lines 8 and 9. If line 7 is a gain and you didn't have any prior year section 1231 losses, or they were recaptured in an earlier year, enter the gain from line 7 as a long-term capital gain on the Schedule D filed with your return and skip lines 8, 9, 11, and 12 below.

	Line	Amount
8 Nonrecaptured net section 1231 losses from prior years. See instructions	8	
9 Subtract line 8 from line 7. If zero or less, enter -0-. If line 9 is zero, enter the gain from line 7 on line 12 below. If line 9 is more than zero, enter the amount from line 8 on line 12 below and enter the gain from line 9 as a long-term capital gain on the Schedule D filed with your return. See instructions	9	

Part II **Ordinary Gains and Losses** (see instructions)

10 Ordinary gains and losses not included on lines 11 through 16 (include property held 1 year or less):

Stmt 80						-1,782,435.

	Line	Amount
11 Loss, if any, from line 7	11	(53,778,949.)
12 Gain, if any, from line 7 or amount from line 8, if applicable	12	
13 Gain, if any, from line 31	13	3,789,467.
14 Net gain or (loss) from Form 4684, lines 31 and 38a	14	
15 Ordinary gain from installment sales from Form 6252, line 25 or 36	15	
16 Ordinary gain or (loss) from like-kind exchanges from Form 8824	16	
17 Combine lines 10 through 16	17	-51,771,917.
18 For all except individual returns, enter the amount from line 17 on the appropriate line of your return and skip lines a and b below. For individual returns, complete lines a and b below:		
a If the loss on line 11 includes a loss from Form 4684, line 35, column (b)(ii), enter that part of the loss here. Enter the part of the loss from income-producing property on Schedule A (Form 1040), line 28, and the part of the loss from property used as an employee on Schedule A (Form 1040), line 23. Identify as from "Form 4797, line 18a." See instructions	18a	
b Redetermine the gain or (loss) on line 17 excluding the loss, if any, on line 18a. Enter here and on Form 1040, line 14	18b	

For Paperwork Reduction Act Notice, see separate instructions.

Form 4797 (2016) Page 2

Part III **Gain From Disposition of Property Under Sections 1245, 1250, 1252, 1254, and 1255** (see instructions)

19 (a) Description of section 1245, 1250, 1252, 1254, or 1255 property:	(b) Date acquired (mo., day, yr.)	(c) Date sold (mo., day, yr.)
A VARIOUS		
B Various	VARIOUS	VARIOUS
C		
D		

These columns relate to the properties on lines 19A through 19D. ▶		Property A	Property B	Property C	Property D
20 Gross sales price (**Note:** *See line 1 before completing.*)	20	3,145,850.	819,826.		
21 Cost or other basis plus expense of sale	21	9,970,544.	1,713,829.		
22 Depreciation (or depletion) allowed or allowable	22	9,807,650.	1,700,514.		
23 Adjusted basis. Subtract line 22 from line 21	23	162,894.	13,315.		
24 Total gain. Subtract line 23 from line 20	24	2,982,956.	806,511.		
25 **If section 1245 property:**					
a Depreciation allowed or allowable from line 22	25a	9,807,650.	1,700,514.		
b Enter the smaller of line 24 or 25a	25b	2,982,956.	806,511.		
26 **If section 1250 property:** If straight line depreciation was used, enter -0- on line 26g, except for a corporation subject to section 291.					
a Additional depreciation after 1975. See instructions	26a				
b Applicable percentage multiplied by the smaller of line 24 or line 26a. See instructions	26b				
c Subtract line 26a from line 24. If residential rental property or line 24 isn't more than line 26a, skip lines 26d and 26e	26c				
d Additional depreciation after 1969 and before 1976	26d				
e Enter the smaller of line 26c or 26d	26e				
f Section 291 amount (corporations only)	26f				
g Add lines 26b, 26e, and 26f	26g				
27 **If section 1252 property:** Skip this section if you didn't dispose of farmland or if this form is being completed for a partnership (other than an electing large partnership).					
a Soil, water, and land clearing expenses	27a				
b Line 27a multiplied by applicable percentage. See instructions	27b				
c Enter the smaller of line 24 or 27b	27c				
28 **If section 1254 property:**					
a Intangible drilling and development costs, expenditures for development of mines and other natural deposits, mining exploration costs, and depletion. See instructions	28a				
b Enter the smaller of line 24 or 28a	28b				
29 **If section 1255 property:**					
a Applicable percentage of payments excluded from income under section 126. See instructions	29a				
b Enter the smaller of line 24 or 29a. See instructions	29b				

Summary of Part III Gains. Complete property columns A through D through line 29b before going to line 30.

30 Total gains for all properties. Add property columns A through D, line 24	30	3,789,467.
31 Add property columns A through D, lines 25b, 26g, 27c, 28b, and 29b. Enter here and on line 13	31	3,789,467.
32 Subtract line 31 from line 30. Enter the portion from casualty or theft on Form 4684, line 33. Enter the portion from other than casualty or theft on Form 4797, line 6	32	

Part IV **Recapture Amounts Under Sections 179 and 280F(b)(2) When Business Use Drops to 50% or Less** (see instructions)

		(a) Section 179	(b) Section 280F(b)(2)
33 Section 179 expense deduction or depreciation allowable in prior years	33		
34 Recomputed depreciation. See instructions	34		
35 Recapture amount. Subtract line 34 from line 33. See the instructions for where to report	35		

Form **6765**

Department of the Treasury
Internal Revenue Service

Credit for Increasing Research Activities

▶ Attach to your tax return.
▶ Information about Form 6765 and its separate instructions is at *www.irs.gov/form6765*.

OMB No. 1545-0619
2016
Attachment Sequence No. 81

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Section A - Regular Credit. Skip this section and go to Section B if you are electing or previously elected (and are not revoking) the alternative simplified credit.

Line	Description	Box	Amount	Box	Amount
1	Certain amounts paid or incurred to energy consortia (see instructions)			1	1,723,298.
2	Basic research payments to qualified organizations (see instructions)	2			
3	Qualified organization base period amount	3			
4	Subtract line 3 from line 2. If zero or less, enter -0-			4	
5	Wages for qualified services (do not include wages used in figuring the work opportunity credit)	5	2,585,567.		
6	Cost of supplies	6	9,839,450.		
7	Rental or lease costs of computers (see instructions)	7			
8	Enter the applicable percentage of contract research expenses (see instructions)	8	417,134,646.		
9	Total qualified research expenses. Add lines 5 through 8	9	429,559,663.		
10	Enter fixed-base percentage, but not more than 16% (0.16) (see instructions)	10	0.030 %		
11	Enter average annual gross receipts (see instructions)	11	5,039,022,108.		
12	Multiply line 11 by the percentage on line 10	12	1,511,707.		
13	Subtract line 12 from line 9. If zero or less, enter -0-	13	428,047,956.		
14	Multiply line 9 by 50% (0.50)	14	214,779,832.		
15	Enter the smaller of line 13 or line 14			15	214,779,832.
16	Add lines 1, 4, and 15			16	216,503,130.
17	Are you electing the reduced credit under section 280C? ▶ Yes ☐ No ☐ If "Yes," multiply line 16 by 13% (0.13). If "No," multiply line 16 by 20% (0.20) and see the instructions for the statement that must be attached. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached . . . Stmt 83			17	28,145,407.

Section B - Alternative Simplified Credit. Skip this section if you are completing Section A.

Line	Description	Box	Amount	Box	Amount
18	Certain amounts paid or incurred to energy consortia (see the line 1 instructions)			18	
19	Basic research payments to qualified organizations (see the line 2 instructions)	19			
20	Qualified organization base period amount (see the line 3 instructions)	20			
21	Subtract line 20 from line 19. If zero or less, enter -0-			21	
22	Add lines 18 and 21			22	
23	Multiply line 22 by 20% (0.20)			23	
24	Wages for qualified services (do not include wages used in figuring the work opportunity credit)	24			
25	Cost of supplies	25			
26	Rental or lease costs of computers (see the line 7 instructions)	26			
27	Enter the applicable percentage of contract research expenses (see the line 8 instructions)	27			
28	Total qualified research expenses. Add lines 24 through 27	28			
29	Enter your total qualified research expenses for the prior 3 tax years. If you had no qualified research expenses in any one of those years, skip lines 30 and 31	29			
30	Divide line 29 by 6.0	30			
31	Subtract line 30 from line 28. If zero or less, enter -0-	31			
32	Multiply line 31 by 14% (0.14). If you skipped lines 30 and 31, multiply line 28 by 6% (0.06)			32	

SCANA CORPORATION 57-0784499

Section B - Alternative Simplified Credit *(continued)*

33	Add lines 23 and 32	33	
34	Are you electing the reduced credit under section 280C? ▶ Yes ☐ No ☐ If "Yes," multiply line 33 by 65% (0.65). If "No," enter the amount from line 33 and see the line 17 instructions for the statement that must be attached. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached	34	

Section C - Current Year Credit

35	Enter the portion of the credit from Form 8932, line 2, that is attributable to wages that were also used to figure the credit on line 17 or line 34 (whichever applies)	35	
36	Subtract line 35 from line 17 or line 34 (whichever applies). If zero or less, enter -0-	36	28,145,407.
37	Credit for increasing research activities from partnerships, S corporations, estates, and trusts	37	
38	Add lines 36 and 37	38	28,145,407.
	• Estates and trusts, go to line 39. • Partnerships and S corporations not electing the payroll tax credit, stop here and report this amount on Schedule K. • Partnerships and S corporations electing the payroll tax credit, complete Section D and report on Schedule K the amount on this line reduced by the amount on line 44. • Eligible small businesses, stop here and report the credit on Form 3800, Part III, line 4i. See instructions for the definition of eligible small business. • Filers other than eligible small businesses, stop here and report the credit on Form 3800, Part III, line 1c. **Note:** Qualified small business filers, other than partnerships and S corporations, electing the payroll tax credit must complete Form 3800 before completing Section D.		
39	Amount allocated to beneficiaries of the estate or trust (see instructions)	39	
40	Estates and trusts, subtract line 39 from line 38. For eligible small businesses, report the credit on Form 3800, Part III, line 4i. See instructions. For filers other than eligible small businesses, report the credit on Form 3800, Part III, line 1c	40	

Section D - Qualified Small Business Payroll Tax Election and Payroll Tax Credit. Skip this section if the payroll tax election does not apply. See instructions.

41	Check this box if you are a qualified small business electing the payroll tax credit. See instructions ☐		
42	Enter the portion of line 36 elected as a payroll tax credit (do not enter more than $250,000). See instructions	42	
43	General business credit carryforward from the current year (see instructions). Partnerships and S corporations skip this line and go to line 44	43	
44	Partnerships and S corporations, enter the smaller of line 36 or line 42. All others, enter the smallest of line 36, line 42, or line 43. Enter here and on Form 8974, line 5. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached	44	

Form **8082**

(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. 84

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity
27-1302931

4 Name, address, and ZIP code of pass-through entity
CANADYS REFINED COAL LLC
TWO PIERCE PLACE
ITASCA, IL 60143

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8 ORDINARY BUSINESS INCOME/LOSS			-2,143,846.	-2,143,846.	
9					
10					
11					

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790
Attachment Sequence No. 84

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY
Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 26-0468152

4 Name, address, and ZIP code of pass-through entity:
APOG LLC
42 INVERNESS CENTER PARKWAY
BIRMINGHAM, AL 35242

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	(b) Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8 ORDINARY BUSINESS INCOME/LOSS	X				
9					
10					
11					

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. 84

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 45-3989987

4 Name, address, and ZIP code of pass-through entity:
BRANDON SHORES COALTECH LLC
TWO PIERCE PLACE
ITASCA, IL 60143

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8 ORDINARY BUSINESS INCOME/LOSS	X		-1,351,550.	-1,351,550.	
9					
10					
11					

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. 84

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 45-3444400

4 Name, address, and ZIP code of pass-through entity:
LOUISA REFINED COAL LLC
6901 DODGE ST SUITE 201
OMAHA, NE 68132

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	(b) Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS			-1,371,983.	-1,371,983.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. 84

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 90-1010358

4 Name, address, and ZIP code of pass-through entity:
MPH ENERGY MIDCO LP
99 RIVER ROAD
COS COB, CT 06807

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	(b) Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	ORDINARY BUSINESS INCOME/LOSS	X		-69.	-69.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790
Attachment Sequence No. 84

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY
Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:
(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 46-2244841

4 Name, address, and ZIP code of pass-through entity:
REPOWER SOUTH LLC
314 SOUTH PINE STREET SUITE 200
SPARTANBURG, SC 29302

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference - between (c) and (d)
8 ORDINARY BUSINESS INCOME/LOSS	X		-45,015.	-45,015.	
9					
10					
11					

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. 84

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity
47-5603086

4 Name, address, and ZIP code of pass-through entity
BRUNNER ISLAND REFINED COAL LLC
2850 GOLF ROAD
ROLLING MEADOWS, IL 60008

5 Internal Revenue Service Center where pass-through entity filed its return
Ogden, UT 84201

6 Tax year of pass-through entity
01/01/2016 to 12/31/2016

7 Your tax year
01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8 ORDINARY BUSINESS INCOME/LOSS	X		-906,042.	-906,042.	
9					
10					
11					

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

LN 8 FINAL K-1 NOT RECEIVED PRIOR TO FILING.

Form **8082** (Rev. December 2011) Department of the Treasury Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790
Attachment Sequence No. 84

Name(s) shown on return: PSNC BLUE RIDGE CORPORATION
Identifying number: 56-1791764

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 76-0479579

4 Name, address, and ZIP code of pass-through entity:
PINE NEEDLE LNG COMPANY LLC
ONE WILLIAMS CENTER PO BOX 2400
TULSA, OK 74102

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8 SEE ATTACHED	X		1,618,996.	1,618,996.	
9					
10					
11					

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

PRELIMINARY K-1 RECEIVED AT TIME OF FILING

Form **8082**

(Rev. December 2011)
Department of the Treasury
Internal Revenue Service

Notice of Inconsistent Treatment or Administrative Adjustment Request (AAR)

(For use by partners, S corporation shareholders, estate and domestic trust beneficiaries, foreign trust owners and beneficiaries, REMIC residual interest holders, and TMPs.)

▶ See separate instructions.

OMB No. 1545-0790

Attachment Sequence No. 84

Name(s) shown on return: PSNC CARDINAL PIPELINE COMPANY

Identifying number: 56-1955423

Part I General Information

1 Check boxes that apply: (a) [X] Notice of inconsistent treatment (b) [ ] Administrative adjustment request (AAR)

2 Identify type of pass-through entity:

(a) [X] Partnership (b) [ ] S corporation (c) [ ] Estate (d) [ ] Trust (e) [ ] REMIC

3 Employer identification number of pass-through entity: 76-0489410

5 Internal Revenue Service Center where pass-through entity filed its return: Ogden, UT 84201

4 Name, address, and ZIP code of pass-through entity:
CARDINAL PIPELINE COMPANY LLC
ONE WILLIAMS CENTER PO BOX 2400
TULSA,OK 74102

6 Tax year of pass-through entity: 01/01/2016 to 12/31/2016

7 Your tax year: 01/01/2016 to 12/31/2016

Part II Inconsistent or Administrative Adjustment Request (AAR) Items

	(a) Description of inconsistent or administrative adjustment request (AAR) items (see instructions)	(b) Inconsistency is in, or AAR is to correct (check boxes that apply): Amount of item	Treatment of item	(c) Amount as shown on Schedule K-1, Schedule Q, or similar statement, a foreign trust statement, or your return, whichever applies (see instructions)	(d) Amount you are reporting	(e) Difference between (c) and (d)
8	SEE ATTACHED	X		3,102,461.	3,102,461.	
9						
10						
11						

Part III Explanations - Enter the Part II item number before each explanation. If more space is needed, continue your explanations on the back.

PRELIMINARY K-1 RECEIVED AT TIME OF FILING

Form **8283** (Rev. December 2014) Department of the Treasury Internal Revenue Service

Noncash Charitable Contributions

▶ Attach to your tax return if you claimed a total deduction of over $500 for all contributed property.
▶ Information about Form 8283 and its separate instructions is at www.irs.gov/form8283.

OMB No. 1545-0908
Attachment Sequence No. 155

Name(s) shown on your income tax return: SOUTH CAROLINA ELECTRIC and GAS COMPANY
Identifying number: 57-0248695

Note. Figure the amount of your contribution deduction before completing this form. See your tax return instructions.

Section A. Donated Property of $5,000 or Less and Publicly Traded Securities - List in this section only items (or groups of similar items) for which you claimed a deduction of $5,000 or less. Also, list publicly traded securities even if the deduction is more than $5,000 (see instructions).

Part I Information on Donated Property - If you need more space, attach a statement.

1	(a) Name and address of the donee organization	(b) If donated property is a vehicle (see instructions), check the box. Also enter the vehicle identification number (unless Form 1098-C is attached).	(c) Description of donated property (For a vehicle, enter the year, make, model, and mileage. For securities, enter the company name and the number of shares.)
A	CALHOUN COUNTY RURAL FIRE DISTRICT		2009 CHEVROLET
B	102 COURTHOUSE DRIVE		
C	ST MATTHEWS, SC 29135		
D			
E			

Note. If the amount you claimed as a deduction for an item is $500 or less, you do not have to complete columns (e), (f), and (g).

	(d) Date of the contribution	(e) Date acquired by donor (mo., yr.)	(f) How acquired by donor	(g) Donor's cost or adjusted basis	(h) Fair market value (see instructions)	(i) Method used to determine the fair market value
A	05/04/2016	2009-06	PURCHASE	3,680.	5,857.	
B						
C						
D						
E						

Part II Partial Interests and Restricted Use Property - Complete lines 2a through 2e if you gave less than an entire interest in a property listed in Part I. Complete lines 3a through 3c if conditions were placed on a contribution listed in Part I; also attach the required statement (see instructions).

2a Enter the letter from Part I that identifies the property for which you gave less than an entire interest ▶ ______
If Part II applies to more than one property, attach a separate statement.

b Total amount claimed as a deduction for the property listed in Part I: (1) For this tax year ▶ ______
(2) For any prior tax years ▶ ______

c Name and address of each organization to which any such contribution was made in a prior year (complete only if different from the donee organization above):

Name of charitable organization (donee)

Address (number, street, and room or suite no.)

City or town, state, and ZIP code

d For tangible property, enter the place where the property is located or kept ▶ ______

e Name of any person, other than the donee organization, having actual possession of the property ▶ ______

		Yes	No
3a	Is there a restriction, either temporary or permanent, on the donee's right to use or dispose of the donated property?		
b	Did you give to anyone (other than the donee organization or another organization participating with the donee organization in cooperative fundraising) the right to the income from the donated property or to the possession of the property, including the right to vote donated securities, to acquire the property by purchase or otherwise, or to designate the person having such income, possession, or right to acquire?		
c	Is there a restriction limiting the donated property for a particular use?		

Form 8283 (Rev 12-2014) Page 2

Name(s) shown on your income tax return	Identifying number
CALHOUN COUNTY RURAL FIRE DISTRICT SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695

Section B. Donated Property Over $5,000 (Except Publicly Traded Securities) - Complete this section for one item (or one group of similar items) for which you claimed a deduction of more than $5,000 per item or group (except contributions of publicly traded securities reported in Section A). Provide a separate form for each property donated unless it is part of a group of similar items. An appraisal is generally required for property listed in Section B. See instructions.

Part I Information on Donated Property - To be completed by the taxpayer and/or the appraiser.

4 Check the box that describes the type of property donated:

a ☐ Art* (contribution of $20,000 or more)
b ☐ Qualified Conservation Contribution
c ☐ Equipment
d ☐ Art* (contribution of less than $20,000)
e ☐ Other Real Estate
f ☐ Securities
g ☐ Collectibles**
h ☐ Intellectual Property
i ☐ Vehicles
j ☐ Other

*Art includes paintings, sculptures, watercolors, prints, drawings, ceramics, antiques, decorative arts, textiles, carpets, silver, rare manuscripts, historical memorabilia, and other similar objects.
**Collectibles include coins, stamps, books, gems, jewelry, sports memorabilia, dolls, etc., but not art as defined above.

Note. In certain cases, you must attach a qualified appraisal of the property. See instructions.

5	(a) Description of donated property (if you need more space, attach a separate statement)	(b) If tangible property was donated, give a brief summary of the overall physical condition of the property at the time of the gift	(c) Appraised fair market value
A			
B			
C			
D			

	(d) Date acquired by donor (mo., yr.)	(e) How acquired by donor	(f) Donor's cost or adjusted basis	(g) For bargain sales, enter amount received	See instructions (h) Amount claimed as a deduction	(i) Date of contribution
A						
B						
C						
D						

Part II Taxpayer (Donor) Statement - List each item included in Part I above that the appraisal identifies as having a value of $500 or less. See instructions.

I declare that the following item(s) included in Part I above has to the best of my knowledge and belief an appraised value of not more than $500 (per item). Enter identifying letter from Part I and describe the specific item. See instructions. ▶

Signature of taxpayer (donor) ▶ Date ▶

Part III Declaration of Appraiser

I declare that I am not the donor, the donee, a party to the transaction in which the donor acquired the property, employed by, or related to any of the foregoing persons, or married to any person who is related to any of the foregoing persons. And, if regularly used by the donor, donee, or party to the transaction, I performed the majority of my appraisals during my tax year for other persons.

Also, I declare that I perform appraisals on a regular basis; and that because of my qualifications as described in the appraisal, I am qualified to make appraisals of the type of property being valued. I certify that the appraisal fees were not based on a percentage of the appraised property value. Furthermore, I understand that a false or fraudulent overstatement of the property value as described in the qualified appraisal or this Form 8283 may subject me to the penalty under section 6701(a) (aiding and abetting the understatement of tax liability). In addition, I understand that I may be subject to a penalty under section 6695A if I know, or reasonably should know, that my appraisal is to be used in connection with a return or claim for refund and a substantial or gross valuation misstatement results from my appraisal. I affirm that I have not been barred from presenting evidence or testimony by the Office of Professional Responsibility.

Sign Here Signature ▶ Title ▶ Date ▶

Business address (including room or suite no.)	Identifying number
102 COURTHOUSE DRIVE	

City or town, state, and ZIP code
ST MATTHEWS, SC 29135

Part IV Donee Acknowledgment - To be completed by the charitable organization.

This charitable organization acknowledges that it is a qualified organization under section 170(c) and that it received the donated property as described in Section B, Part I, above on the following date ▶

Furthermore, this organization affirms that in the event it sells, exchanges, or otherwise disposes of the property described in Section B, Part I (or any portion thereof) within 3 years after the date of receipt, it will file Form 8282, Donee Information Return, with the IRS and give the donor a copy of that form. This acknowledgment does not represent agreement with the claimed fair market value.

Does the organization intend to use the property for an unrelated use? . . . . ▶ ☐ Yes ☐ No

Name of charitable organization (donee)	Employer identification number	
Address (number, street, and room or suite no.)	City or town, state, and ZIP code	
Authorized signature	Title	Date

Form **8835**

Department of the Treasury
Internal Revenue Service

Renewable Electricity, Refined Coal, and Indian Coal Production Credit

▶ Attach to your tax return.
▶ Information about Form 8835 and its separate instructions is at *www.irs.gov/form8835*.

OMB No. 1545-1362
2016
Attachment Sequence No. 95

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Electricity and Refined Coal Produced at Qualified Facilities Placed in Service After October 22, 2004 (After October 2, 2008, for Electricity Produced From Marine and Hydrokinetic Renewables), and Indian Coal Produced at Facilities Placed in Service After August 8, 2005

			(a) Kilowatt-hours produced and sold (see instructions)	(b) Rate	(c) Column (a) x Column (b)
1	Electricity produced at qualified facilities using:				
a	Wind	1a		0.023	
b	Closed-loop biomass	1b		0.023	
c	Geothermal	1c		0.023	
d	Solar	1d		0.023	

e	Add column (c) of lines 1a through 1d and enter here (see instructions)	1e	

			(a) Kilowatt-hours produced and sold (see instructions)	(b) Rate	(c) Column (a) x Column (b)
2	Electricity produced at qualified facilities using:				
a	Open-loop biomass	2a		0.012	
b	Small irrigation power	2b		0.012	
c	Landfill gas	2c		0.012	
d	Trash	2d		0.012	
e	Hydropower	2e		0.012	
f	Marine and hydrokinetic renewables	2f		0.012	

g	Add column (c) of lines 2a through 2f and enter here (see instructions)	2g	
3	Add lines 1e and 2g	3	
4	Phaseout adjustment (see instructions) $ ______ x ______	4	
5	Subtract line 4 from line 3	5	
	Refined coal produced at a qualified refined coal production facility		
6	Tons produced and sold (see instructions) 1212180 x $6.810	6	8,254,946.
7	Phaseout adjustment (see instructions) $ ______ x ______	7	
8	Subtract line 7 from line 6	8	8,254,946.
9	Reserved	9	
	Indian coal produced at a qualified Indian coal production facility		
10	Tons produced and sold (see instructions) ______ x $2.387	10	
11	Credit before reduction. Add lines 5, 8, and 10	11	8,254,946.
	Reduction for government grants, subsidized financing, and other credits:		
12	Total of government grants, proceeds of tax-exempt government obligations, subsidized energy financing, and any federal tax credits allowed for the project for this and all prior tax years (see instructions)	12	
13	Total of additions to the capital account for the project for this and all prior tax years	13	
14	Divide line 12 by line 13. Show as a decimal carried to at least 4 places	14	
15	Multiply line 11 by the smaller of 1/2 or line 14	15	
16	Subtract line 15 from line 11	16	8,254,946.
17a	Enter the amount from line 16 applicable to wind facilities the construction of which began during 2017	17a	
b	Multiply line 17a by 20% (0.20)	17b	
18	Subtract line 17b from line 16	18	8,254,946.
19	Renewable electricity, refined coal, and Indian coal production credit from partnerships, S corporations, cooperatives, estates, and trusts (see instructions)	19	
20	Add lines 18 and 19. Cooperatives, estates, and trusts, go to line 21. Partnerships and S corporations, stop here and report this amount on Schedule K. All others: For electricity or refined coal produced during the 4-year period beginning on the date the facility was placed in service or Indian coal produced, stop here and report the applicable part of this amount on Form 3800, Part III, line 4e. For all other production of electricity or refined coal, stop here and report the applicable part of this amount on Form 3800, Part III, line 1f (see instructions)	20	8,254,946.
21	Amount allocated to patrons of the cooperative or beneficiaries of the estate or trust (see instructions)	21	
22	Cooperatives, estates, and trusts, subtract line 21 from line 20. For electricity or refined coal produced during the 4-year period beginning on the date the facility was placed in service or Indian coal produced, report the applicable part of this amount on Form 3800, Part III, line 4e. For all other production of electricity or refined coal, report the applicable part of this amount on Form 3800, Part III, line 1f	22	

For Paperwork Reduction Act Notice, see separate instructions.
JSA
6X2636 3.000

00002U M16C 09/28/2017 12:42:01 V16-7F 57-0784499

Form **8903** (Rev. December 2010) Department of the Treasury Internal Revenue Service

Domestic Production Activities Deduction

▶ Attach to your tax return. ▶ See separate instructions.

OMB No. 1545-1984

Attachment Sequence No. **143**

Name(s) as shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Note. Do not complete column (a), unless you have oil-related production activities. Enter amounts for all activities in column (b), including oil-related production activities.

Line	Description		(a) Oil-related production activities	(b) All activities
1	Domestic production gross receipts (DPGR)	1		4,497,365,433.
2	Allocable cost of goods sold. If you are using the small business *simplified overall method, skip lines 2 and 3*	2		4,338,581,720.
3	Enter deductions and losses allocable to DPGR (see instructions)	3		374,307,595.
4	If you are using the small business simplified overall method, enter the amount of cost of goods sold and other deductions or losses you ratably apportion to DPGR. All others, skip line 4	4		
5	Add lines 2 through 4	5		4,712,889,315.
6	Subtract line 5 from line 1	6		-215,523,882.
7	Qualified production activities income from estates, trusts, and certain partnerships and S corporations (see instructions)	7		
8	Add lines 6 and 7. Estates and trusts, go to line 9, all others, skip line 9 and go to line 10	8		
9	Amount allocated to beneficiaries of the estate or trust (see instructions)	9		
10a	**Oil-related qualified production activities income.** Estates and trusts, subtract line 9, column (a), from line 8, column (a), all others, enter amount from line 8, column (a). If zero or less, enter -0- here	10a		
b	**Qualified production activities income.** Estates and trusts, subtract line 9, column (b), from line 8, column (b), all others, enter amount from line 8, column (b). If zero or less, enter -0- here, skip lines 11 through 21, and enter -0- on line 22	10b		

Line	Description		Amount
11	Income limitation (see instructions): • Individuals, estates, and trusts. Enter your adjusted gross income figured without the domestic production activities deduction • All others. Enter your taxable income figured without the domestic production activities deduction (tax-exempt organizations, see instructions)	11	
12	Enter the smaller of line 10b or line 11. If zero or less, enter -0- here, skip lines 13 through 21, and enter -0- on line 22	12	
13	Enter 9% of line 12	13	
14a	Enter the smaller of line 10a or line 12 — 14a		
b	Reduction for oil-related qualified production activities income. Multiply line 14a by 3%	14b	
15	Subtract line 14b from line 13	15	
16	Form W-2 wages (see instructions)	16	
17	Form W-2 wages from estates, trusts, and certain partnerships and S corporations (see instructions)	17	
18	Add lines 16 and 17. Estates and trusts, go to line 19, all others, skip line 19 and go to line 20	18	
19	Amount allocated to beneficiaries of the estate or trust (see instructions)	19	
20	Estates and trusts, subtract line 19 from line 18, all others, enter amount from line 18	20	
21	Form W-2 wage limitation. Enter 50% of line 20	21	
22	Enter the smaller of line 15 or line 21	22	
23	Domestic production activities deduction from cooperatives. Enter deduction from Form 1099-PATR, box 6	23	
24	Expanded affiliated group allocation (see instructions)	24	
25	**Domestic production activities deduction.** Combine lines 22 through 24 and enter the result here and on Form 1040, line 35; Form 1120, line 25; or the applicable line of your return	25	

Form **8911**

Department of the Treasury
Internal Revenue Service

Alternative Fuel Vehicle Refueling Property Credit

▶ Attach to your tax return.

▶ Information about Form 8911 and its instructions is at *www.irs.gov/form8911*.

OMB No. 1545-1981

2016

Attachment Sequence No. **151**

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Part I — Total Cost of Refueling Property

1	Total cost of qualified alternative fuel vehicle refueling property placed in service during the tax year (see **What's New** in the instructions)	1	9,755.

Part II — Credit for Business/Investment Use Part of Refueling Property

2	Business/investment use part (see instructions)	2	9,755.
3	Section 179 expense deduction (see instructions)	3	
4	Subtract line 3 from line 2	4	9,755.
5	Multiply line 4 by 30% (0.30)	5	2,927.
6	*Maximum business/investment use part of credit* (see instructions)	6	2,927.
7	Enter the **smaller** of line 5 or line 6	7	2,927.
8	Alternative fuel vehicle refueling property credit from partnerships and S corporations (see instructions)	8	
9	**Business/investment use part of credit.** Add lines 7 and 8. Partnerships and S corporations, stop here and report this amount on Schedule K. All others, report this amount on Form 3800, Part III, line 1s	9	2,927.

Part III — Credit for Personal Use Part of Refueling Property

10	Subtract line 2 from line 1. If zero, stop here; do not file this form unless you are claiming a credit on line 9	10	
11	Multiply line 10 by 30% (0.30)	11	
12	Maximum personal use part of credit (see instructions)	12	
13	Enter the **smaller** of line 11 or line 12	13	
14	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46; or the sum of the amounts from Form 1040NR, lines 42 and 44. • Other filers. Enter the regular tax before credits from your return.	14	
15	Credits that reduce regular tax before the alternative fuel vehicle refueling property credit:		
a	Foreign tax credit — 15a		
b	Certain allowable credits (see instructions) — 15b		
c	Add lines 15a and 15b	15c	
16	Net regular tax. Subtract line 15c from line 14. If zero or less, enter -0- and stop here; do not file this form unless you are claiming a credit on line 9	16	
17	Tentative minimum tax (see instructions): • Individuals. Enter the amount from Form 6251, line 33. • Other filers. Enter the tentative minimum tax from your alternative minimum tax form or schedule.	17	
18	Subtract line 17 from line 16. If zero or less, stop here; do not file this form unless you are claiming a credit on line 9	18	
19	**Personal use part of credit.** Enter the smaller of line 13 or line 18 here and on Form 1040, line 54; Form 1040NR, line 51; or the appropriate line of your return. If line 18 is smaller than line 13, see instructions	19	

For Paperwork Reduction Act Notice, see instructions. Form **8911** (2016)

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Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120*.

OMB No. 1545-0123

2016

Name of common parent
SCANA CORPORATION

Employer identification number
57-0784499

Name of subsidiary

Employer identification number

Part I Cost of Goods Sold

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs		361,986.		361,986.
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)	235,499,349.	Stmt 88 -72,802,725.		162,696,624.
7 Other items with no differences	1,933,500,729.	Stmt 89		1,933,500,729.
8 Total cost of goods sold. Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	2,169,000,078.	-72,440,739.		2,096,559,339.

For Paperwork Reduction Act Notice, see instructions.

Form **8916-A** (2016)

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SCANA CORPORATION 57-0784499

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income		15,820.		
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	63,471.			63,471.
5	Other interest income Stmt 91	40,167,076.	200,970,065.		241,137,141.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	40,230,547.	200,985,885.		241,216,432.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,317,328.			1,317,328.
4	Other interest expense Stmt 94	340,952,042.	42,908,253.		383,860,295.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	342,269,370.	42,908,253.		385,177,623.

Form 8916-A (2016)

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120*.

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: SCANA CORPORATION
Employer identification number: 57-0784499

Part I Cost of Goods Sold

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs				
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)				
7 Other items with no differences				
8 **Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions				

SCANA CORPORATION 57-0784499

Form 8916-A (2016) Page 2

Part II **Interest Income**

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income		15,820.		
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	8,327,745.			8,327,745.
5	Other interest income	1,595,218.	-1,382,225.		212,993.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	9,922,963.	-1,366,405.		8,556,558.

Part III **Interest Expense**

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group				
4	Other interest expense	54,743,724.	-3,597.		54,740,127.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3 See instructions.	54,743,724.	-3,597.		54,740,127.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at www.irs.gov/form1120.

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION | Employer identification number: 57-0784499

Name of subsidiary: SCANA SERVICES INC | Employer identification number: 57-1092169

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences	74,318,188.			74,318,188.
8	Total cost of goods sold. Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	74,318,188.			74,318,188.

SCANA SERVICES INC 57-1092169

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	716,842.			716,842.
5	Other interest income	13,954.			13,954.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	730,796.			730,796.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	9,118,712.			9,118,712.
4	Other interest expense	462.			462.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	9,119,174.			9,119,174.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at www.irs.gov/form1120.

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: SOUTH CAROLINA ELECTRIC and GAS COMPANY
Employer identification number: 57-0248695

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs		222,266.		222,266.
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)		-16,857,064.		-16,857,064.
7	Other items with no differences	1,104,945,601.			1,104,945,601.
8	Total cost of goods sold. Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	1,104,945,601.	-16,634,798.		1,088,310,803.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	59,543.			59,543.
5	Other interest income	31,945,071.	203,397,097.		235,342,168.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	32,004,614.	203,397,097.		235,401,711.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	6,644,766.			6,644,766.
4	Other interest expense	248,048,905.	42,604,735.		290,653,640.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	254,693,671.	42,604,735.		297,298,406.

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Form **8916-A** Department of the Treasury Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION — Employer identification number: 57-0784499

Name of subsidiary: SOUTH CAROLINA FUEL CO INC — Employer identification number: 57-0691209

Part I Cost of Goods Sold

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs				
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)	235,135,917.	-55,780,868.		179,355,049.
7 Other items with no differences				
8 Total cost of goods sold. Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	235,135,917.	-55,780,868.		179,355,049.

SOUTH CAROLINA FUEL CO INC 57-0691209

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group				
5	Other interest income				
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.				

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	58,045.			58,045.
4	Other interest expense	1,787,247.			1,787,247.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	1,845,292.			1,845,292.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123
2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: SC GENERATING COMPANY INC
Employer identification number: 57-0784498

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences	113,725,200.			113,725,200.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	113,725,200.			113,725,200.

SC GENERATING COMPANY INC 57-0784498

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	29.			29.
5	Other interest income	54,017.	-31,785.		22,232.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	54,046.	-31,785.		22,261.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,212,200.			1,212,200.
4	Other interest expense	14,133,651.	-482,617.		13,651,034.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	15,345,851.	-482,617.		14,863,234.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent	Employer identification number
SCANA CORPORATION	57-0784499
Name of subsidiary	**Employer identification number**
SCANA ENERGY MARKETING INC	57-0850977

Part I Cost of Goods Sold

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs		77,007.		77,007.
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)				
7 Other items with no differences	812,053,946.			812,053,946.
8 Total cost of goods sold. Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	812,053,946.	77,007.		812,130,953.

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SCANA ENERGY MARKETING INC 57-0850977

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	373,958.			373,958.
5	Other interest income	221.			221.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	374,179.			374,179.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,083,289.			1,083,289.
4	Other interest expense	-12,434.			-12,434.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	1,070,855.			1,070,855.

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Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at www.irs.gov/form1120.

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION
Employer identification number: 57-0784499

Name of subsidiary: SERVICECARE INC
Employer identification number: 57-1007394

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs				
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)				
7	Other items with no differences				
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions				

SERVICECARE INC 57-1007394

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	5,863.			5,863.
5	Other interest income				
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	5,863.			5,863.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group				
4	Other interest expense				
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.				

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Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION

Employer identification number: 57-0784499

Name of subsidiary: PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORATED

Employer identification number: 56-2128483

Part I Cost of Goods Sold

	Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Amounts attributable to cost flow assumptions				
2	Amounts attributable to:				
a	Stock option expense				
b	Other equity-based compensation				
c	Meals and entertainment				
d	Parachute payments				
e	Compensation with section 162(m) limitation				
f	Pension and profit sharing				
g	Other post-retirement benefits				
h	Deferred compensation				
i	Reserved				
j	Amortization				
k	Depletion				
l	Depreciation				
m	Corporate-owned life insurance premiums				
n	Other section 263A costs		62,713.		62,713.
3	Inventory shrinkage accruals				
4	Excess inventory and obsolescence reserves				
5	Lower of cost or market write-downs				
6	Other items with differences (attach statement)	363,432.	-164,793.		198,639.
7	Other items with no differences	204,814,883.			204,814,883.
8	**Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	205,178,315.	-102,080.		205,076,235.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	96.			96.
5	Other interest income	6,572,549.	-1,013,022.		5,559,527.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions	6,572,645.	-1,013,022.		5,559,623.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	1,022,792.			1,022,792.
4	Other interest expense	24,154,282.	789,732.		24,944,014.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	25,177,074.	789,732.		25,966,806.

Form **8916-A**

Department of the Treasury
Internal Revenue Service

Supplemental Attachment to Schedule M-3

▶ Attach to Schedule M-3 for Form 1065, 1120, 1120-L, 1120-PC, or 1120S.
▶ Information about Form 8916-A and its instructions is at www.irs.gov/form1120.

OMB No. 1545-0123

2016

Name of common parent: SCANA CORPORATION

Employer identification number: 57-0784499

Name of subsidiary: ELIMINATIONS SCANA CORPORATIO

Employer identification number:

Part I Cost of Goods Sold

Cost of Goods Sold Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 Amounts attributable to cost flow assumptions				
2 Amounts attributable to:				
a Stock option expense				
b Other equity-based compensation				
c Meals and entertainment				
d Parachute payments				
e Compensation with section 162(m) limitation				
f Pension and profit sharing				
g Other post-retirement benefits				
h Deferred compensation				
i Reserved				
j Amortization				
k Depletion				
l Depreciation				
m Corporate-owned life insurance premiums				
n Other section 263A costs				
3 Inventory shrinkage accruals				
4 Excess inventory and obsolescence reserves				
5 Lower of cost or market write-downs				
6 Other items with differences (attach statement)				
7 Other items with no differences	-376,357,089.			-376,357,089.
8 **Total cost of goods sold.** Add lines 1 through 7 in columns a, b, c, and d. Enter totals on the applicable Schedule M-3. See instructions	-376,357,089.			-376,357,089.

For Paperwork Reduction Act Notice, see instructions.

Form **8916-A** (2016)

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ELIMINATIONS SCANA CORPORATIO

Form 8916-A (2016) Page 2

Part II Interest Income

	Interest Income Item	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Tax-exempt interest income				
2	Interest income from hybrid securities				
3	Sale/lease interest income				
4a	Intercompany interest income - From outside tax affiliated group				
4b	Intercompany interest income - From tax affiliated group	-9,420,605.			-9,420,605.
5	Other interest income	-13,954.			-13,954.
6	Total interest income. Add lines 1 through 5 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	-9,434,559.			-9,434,559.

Part III Interest Expense

	Interest Expense Item	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1	Interest expense from hybrid securities				
2	Lease/purchase interest expense				
3a	Intercompany interest expense - Paid to outside tax affiliated group				
3b	Intercompany interest expense - Paid to tax affiliated group	-17,822,476.			-17,822,476.
4	Other interest expense	-1,903,795.			-1,903,795.
5	Total interest expense. Add lines 1 through 4 in columns a, b, c, and d. Enter total on the applicable Schedule M-3. See instructions.	-19,726,271.			-19,726,271.

Form **8925** (Rev. January 2010) Department of the Treasury Internal Revenue Service (99)

Report of Employer-Owned Life Insurance Contracts

OMB No. 1545-2089

▶ Attach to the policyholder's tax return - See instructions.

Attachment Sequence No. 160

Name(s) as shown on return	Identifying number
SCANA CORPORATION	57-0784499
Name of policyholder, if different from above	Identifying number, if different from above

Type of business

HOLDING COMPANY UTILITY

1	Enter the number of employees the policyholder had at the end of the tax year	1	5,775.
2	Enter the number of employees included on line 1 who were insured at the end of the tax year under the policyholder's employer-owned life insurance contract(s) issued after August 17, 2006. See *Section 1035 exchanges* on page 2 for an exception	2	3.
3	Enter the total amount of employer-owned life insurance in force at the end of the tax year for employees who were insured under the contract(s) specified on line 2	3	1,160,000.
4a	Does the policyholder have a valid consent (see instructions) for each employee included on line 2? [X] Yes [ ] No		
b	If "No," enter the number of employees included on line 2 for whom the policyholder does not have a valid consent	4b	

General Instructions

Section references are to the Internal revenue Code unless otherwise noted.

Purpose of Form

Use Form 8925 to report the number of employees covered by employer-owned life insurance contracts issued after August 17, 2006, and the total amount of employer-owned life insurance in force on those employees at the end of the tax year. Policyholders must also indicate whether a valid consent has been received from each covered employee, and the number of covered employees for which a valid consent has not been received.

See sections 101(j) and 6039I, and Notice 2009-48, 2009-24 I.R.B. 1085, for more information.

Definitions

Employer-owned life insurance contract. For purposes of Form 8925, an insurance contract is an employer-owned life insurance contract if it is owned by a policyholder as defined below, and covers the life of the policyholder's employee(s) on the date the life insurance contract is issued. If you have master contracts, see section 101(j)(3) for additional information.

Policyholder. For purposes of Form 8925 and these instructions, a policyholder is an "applicable policyholder" as defined in section 101(j)(3)(B). Generally, a policyholder is the person who owns the employer-owned life insurance contract, and who is (a) engaged in a trade or business that employs the person insured under the employer-owned life insurance contract and (b) the direct or indirect beneficiary of the employer-owned life insurance contract.

Related person. A related person is considered a policyholder if that person is (a) related to the policyholder (defined earlier) under sections 267(b) or 707(b)(1), or (b) engaged in a trade or business under common control with the policyholder. See sections 52(a) and (b).

Employee. Employee includes an officer, director, or highly compensated employee under section 414(q).

Insured. An individual must be a U.S. citizen or resident to be considered insured under an employer-owned life insurance contract. Both individuals covered by a contract covering the joint lives of two individuals are considered insured.

Notice and consent requirements. To qualify as an employer-owned life insurance contract, the policyholder must meet the notice and consent requirements listed below before the issuance of the contract.

1. Provide written notification to the employee stating the policyholder intends to insure the employee's life and the maximum face amount for which the employee could be insured at the time the contract was issued.

The written notification must include a disclosure of the face amount of life insurance, either in dollars or as a multiple of salary, that the policyholder reasonably expects to purchase with regard to the employee during the course of the employee's tenure. Additional notice and consent are required if the aggregate face amount of the employer-owned life insurance contracts with regard to an employee exceeds the amount of which the employee was given notice and to which the employee consented. See Q&A-9 and Q&A-12 in Notice 2009-48.

2. Provide written notification to the employee that the policyholder will be a beneficiary of any proceeds payable upon the death of the employee.

3. Received written consent from the employee. See *Valid consent* under the instructions for line 4a.

Electronic notification and consent. The written notification and consent requirement can be met electronically only if the system for electronic notification and consent meets requirements 1 through 3, above. See Q&A-11 in Notice 2009-48 for more information.

Issue date of contract. Generally, the issue date of a life insurance contract is the date on the policy assigned by the insurance company on or after the date of application. For purposes of meeting the notice and consent requirements, the issue date of the employer-owned life insurance contract is the later of (1) the date of application of coverage, (2) the effective date of coverage, or (3) the formal issuance of the contract. See Q&A-4 in Notice 2009-48 for more information.

Regulation Section 1.263(a)-1(f) - De Minimis Safe Harbor Election

Taxpayer Name: SCANA CORPORATION

Taxpayer Address: 220 OPERATION WAY CAYCE SC 29033-3701

Taxpayer ID Number: 57-0784499

Year-End: 12/31/2016

Under IRC Regulation Section 1.263(a)-1(f), the taxpayer hereby elects to apply the de minimis safe harbor election.

Election To Deduct Start-Up Expenditures
IRC Section 195

Taxpayer Name: SCANA SERVICES INC
Taxpayer ID Number: 57-1092169
Year-end: 12/31/2016

Section 195 Election

In accordance with IRC Sec. 195, taxpayer hereby elects to deduct start-up expenditures up to $5,000 in the tax year in which the business begins. The remainder of the startup expenditures are deductible ratably over 180 months, beginning with 07/14/2005, the month that the corporation's active trade or business began (or was acquired).

The trade or business of the taxpayer to which this election relates is SCANA Pharmacy

The start-up expense incurred are:

Description of Start-Up Expense	Date Incurred	Amount
SALARIES AND MISCELLANEOUS	06/01/2005	165,233.
	Total	165,233.

SCANA CORPORATION 57-0784499

Consolidated Schedules
1120 Page 1

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1a	Gross receipts or sales	5,217,353,893.	-719,988,460.		4,497,365,433.
1b	Returns and allowances				
1c	Balance	5,217,353,893.	-719,988,460.		4,497,365,433.
2	Cost of goods sold	2,494,537,833.	-376,357,089.		2,118,180,744.
3	Gross profit	2,722,816,060.	-343,631,371.		2,379,184,689.
4	Dividends	337,492.			337,492.
5	Interest	250,650,991.	-9,434,559.		241,216,432.
6	Gross rents	22,485,964.	-6,676,572.		15,809,392.
7	Gross royalties				
8	Capital gain net income	232,440.		-1,646.	230,794.
9	Net gain or (loss) from Form 4797	-51,773,563.		1,646.	-51,771,917.
10	Other income	22,326,457.	-722,418.		21,604,039.
11	Total income	2,967,075,841.	-360,464,920.		2,606,610,921.
12	Compensation of officers	15,144,833.			15,144,833.
13	Salaries and wages	196,776,880.	-116,276,230.		80,500,650.
14	Repairs and maintenance	304,310,651.	-55,589,061.		248,721,590.
15	Bad debts	10,405,142.	-57,907.		10,347,235.
16	Rents	19,815,945.	-15,121,806.		4,694,139.
17	Taxes and licenses	273,004,181.	-16,528,705.		256,475,476.
18	Interest	404,903,894.	-19,726,271.		385,177,623.
19	Charitable contributions	3,585,739.	NONE	-3,585,739.	NONE
20	Depreciation	674,906,524.			674,906,524.
21	Depletion				
22	Advertising	13,299,533.	-814,120.		12,485,413.
23	Pension, profit-sharing etc., plans	1,059,828.	-364,871.		694,957.
24	Employee benefit programs	86,473,736.	-29,670,928.		56,802,808.
25	Domestic production activities deduction				
26	Other deductions	1,029,624,650.	-106,315,021.		923,309,629.
27	Total deductions	3,033,311,536.	-360,464,920.	-3,585,739.	2,669,260,877.
28	Taxable income before NOL & Spec. Deductions	-66,235,695.	NONE	3,585,739.	-62,649,956.
29	NOL,Spec. deductions	212,200.			212,200.
30	Taxable income	-66,447,895.	NONE	3,585,739.	-62,862,156.

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SCANA CORPORATION 57-0784499

Consolidated Schedules 1120 Page 1		SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483
1a	Gross receipts or sales		413,279,684.	2,998,699,530.	237,225,342.	193,888,768.	938,277,430.		435,983,139.
1b	Returns and allowances								
1c	Balance		413,279,684.	2,998,699,530.	237,225,342.	193,888,768.	938,277,430.		435,983,139.
2	Cost of goods sold		74,318,188.	1,088,310,803.	179,355,049.	113,725,200.	833,752,358.		205,076,235.
3	Gross profit		338,961,496.	1,910,388,727.	57,870,293.	80,163,568.	104,525,072.		230,906,904.
4	Dividends	337,492.							
5	Interest	8,556,558.	730,796.	235,401,711.		22,261.	374,179.	5,863.	5,559,623.
6	Gross rents		735,204.	20,964,105.		10,903.			775,752.
7	Gross royalties								
8	Capital gain net income	230,794.	NONE	NONE			1,646.		
9	Net gain or (loss) from Form 4797		-696,096.	-38,024,208.		-3,530,135.			-9,523,124.
10	Other income	-33,798.	722,418.	10,233,647.		-585,541.	10,217.		11,979,514.
11	Total income	9,091,046.	340,453,818.	2,138,963,982.	57,870,293.	76,081,056.	104,911,114.	5,863.	239,698,669.
12	Compensation of officers			15,144,833.					
13	Salaries and wages	371,386.	102,987,502.	55,188,382.	3,529.	1,541,100.	16,135,231.	2,541.	20,547,209.
14	Repairs and maintenance		51,734,339.	215,401,652.		18,725,651.	574,178.	356.	17,874,475.
15	Bad debts		57,907.	6,349,958.			3,429,159.	-593.	568,711.
16	Rents		9,357,222.	6,587,833.		78,729.	1,974,447.		1,817,714.
17	Taxes and licenses	287,115.	16,538,705.	230,655,590.	2,978.	7,397,963.	3,270,779.	359.	14,849,692.
18	Interest	54,740,127.	9,119,174.	297,298,406.	1,845,292.	14,863,234.	1,070,855.		25,966,806.
19	Charitable contributions	145.	NONE	2,736,550.		12,417.	453,434.		383,193.
20	Depreciation		15,840,260.	431,921,192.	46,060,920.	19,590,347.	955,303.		160,538,502.
21	Depletion								
22	Advertising		814,120.	371,874.			11,082,729.		1,030,810.
23	Pension, profit-sharing etc., plans	-1,502,226.	364,871.	1,368,809.	11.	19,491.	53,040.	849,150.	-93,318.
24	Employee benefit programs	-2,896,149.	29,670,928.	43,614,763.	1,038.	1,568,904.	4,321,315.	313,850.	9,879,087.
25	Domestic production activities deduction								
26	Other deductions	23,866,947.	93,283,085.	862,060,752.	236,577.	2,727,592.	13,403,489.	32,380.	34,013,125.
27	Total deductions	74,867,345.	329,768,113.	2,168,700,594.	48,150,345.	66,525,428.	56,723,959.	1,198,043.	287,376,006.
28	Taxable income before NOL & Spec. Deductions	-65,776,299.	10,685,705.	-29,736,612.	9,719,948.	9,555,628.	48,187,155.	-1,192,180.	-47,677,337.
29	NOL,Spec. deductions	212,200.							
30	Taxable income	-65,988,499.	10,685,705.	-29,736,612.	9,719,948.	9,555,628.	48,187,155.	-1,192,180.	-47,677,337.

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SCANA CORPORATION 57-0784499

Consolidated Schedules 1120 Page 1	CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
1a Gross receipts or sales		
1b Returns and allowances		
1c Balance		
2 Cost of goods sold		
3 Gross profit		
4 Dividends		
5 Interest		
6 Gross rents		
7 Gross royalties		
8 Capital gain net income		
9 Net gain or (loss) from Form 4797		
10 Other income		
11 Total income		
12 Compensation of officers		
13 Salaries and wages		
14 Repairs and maintenance		
15 Bad debts		
16 Rents		
17 Taxes and licenses	1,000.	
18 Interest		
19 Charitable contributions		
20 Depreciation		
21 Depletion		
22 Advertising		
23 Pension, profit-sharing etc., plans		
24 Employee benefit programs		
25 Domestic production activities deduction		
26 Other deductions	703.	
27 Total deductions	1,703.	
28 Taxable income before NOL & Spec. Deductions	-1,703.	NONE
29 NOL,Spec. deductions		
30 Taxable income	-1,703.	NONE

SCANA CORPORATION 57-0784499

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Line 10 - Other Income

SCANA CORPORATION	
INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	-33,798.
Subtotal	-33,798.
SCANA SERVICES INC	
GAIN ON LAND SALES	269,581.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	452,837.
Subtotal	722,418.
SOUTH CAROLINA ELECTRIC and GAS COMPANY	
GAIN ON LAND SALES	
INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	-4,833,278.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	15,066,925.
Subtotal	10,233,647.
SC GENERATING COMPANY INC	
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-585,541.
Subtotal	-585,541.
SCANA ENERGY MARKETING INC	
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	10,217.
Subtotal	10,217.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA	
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	11,979,514.
Subtotal	11,979,514.

Continued on next page

SCANA CORPORATION 57-0784499

1120 Page 1 Detail

Line 10 - Other Income (Cont'd)

ELIMINATIONS SCANA CORPORATIO

GAIN ON LAND SALES	-269,581.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-452,837.
Subtotal	-722,418.
Total Line 10 - Other Income	21,604,039.

SCANA CORPORATION 57-0784499

1120 Page 1 Detail

Line 19 - Contributions deduction

1.	Taxable income (excluding contributions and domestic production activities deduction)	-62,649,956.
2.	Less: NOL carryover	
3.	Plus: Capital Loss carryback	
4.	Taxable income without regard to contributions, special deductions, domestic production activities deduction, NOL carrybacks, and capital loss carrybacks	-62,649,956.
5.	Contribution deduction limitation (Taxable income x 10%)	NONE
6.	Amount of deductible contributions	3,585,739.
7.	Contribution deduction (Lesser of line 5 or line 6)	NONE

Line 19 - 5 Year contribution carryover

Year ending	Amount Available	Amount Utilized	Converted to NOL Carryover	Carryover to Next Year
12/31/2016	3,585,739.	NONE		3,585,739.
Total	3,585,739.	NONE		3,585,739.

SCANA CORPORATION 57-0784499

1120 Page 1 Detail

Line 26 - Other Deductions

SCANA CORPORATION

INJURIES AND DAMAGES	44,555.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	-3,186,573.
OFFICE SUPPLIES AND EXPENSES	1,926.
OUTSIDE SERVICES	2,030.
SELLING EXPENSES	-154,162.
ESOP DIVIDENDS	27,159,171.
Subtotal	23,866,947.

SCANA SERVICES INC

Amortization	2,139,118.
INJURIES AND DAMAGES	4,590,943.
INSURANCE	139,629.
MERCHANDISING EXPENSES	1,301,752.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	21,072,152.
OFFICE SUPPLIES AND EXPENSES	35,981,453.
OUTSIDE SERVICES	27,195,321.
SELLING EXPENSES	-19,408.
RESEARCH AND DEVELOPMENT	882,125.
Subtotal	93,283,085.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

Amortization	8,116,771.
Travel, Meals and Entertainment	1,001,437.
POLLUTION CONTROL	10,705,348.
INJURIES AND DAMAGES	5,807,027.
INSURANCE	7,158,823.
MERCHANDISING EXPENSES	1,031,448.
MISCELLANEOUS DEDUCTIONS	39,340,430.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	51,659,518.
OFFICE SUPPLIES AND EXPENSES	20,537,993.
OUTSIDE SERVICES	16,406,895.
PIPELINE INTEGRITY	-17,084,713.
481A ADJUSTMENT	-4,228,547.
RESEARCH AND DEVELOPMENT	721,608,322.
Subtotal	862,060,752.

Continued on next page

SCANA CORPORATION 57-0784499

1120 Page 1 Detail

Line 26 - Other Deductions (Cont'd)

SOUTH CAROLINA FUEL CO INC

OFFICE SUPPLIES AND EXPENSES	65.
OUTSIDE SERVICES	236,512.
Subtotal	236,577.

SC GENERATING COMPANY INC

Amortization	101,793.
Travel, Meals and Entertainment	372.
INJURIES AND DAMAGES	198,511.
INSURANCE	654,403.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	713,109.
OFFICE SUPPLIES AND EXPENSES	538,492.
OUTSIDE SERVICES	520,912.
Subtotal	2,727,592.

SCANA ENERGY MARKETING INC

Amortization	1,098,647.
Travel, Meals and Entertainment	192,020.
DIRECTORS ENDOWMENT	
INJURIES AND DAMAGES	80,987.
INSURANCE	264,821.
LIFE INSURANCE	
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	2,193,541.
OFFICE SUPPLIES AND EXPENSES	7,529,342.
OUTSIDE SERVICES	1,912,193.
PENALTIES AND FINES	
RESEARCH AND DEVELOPMENT	131,938.
Subtotal	13,403,489.

SERVICECARE INC

INJURIES AND DAMAGES	3,709.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	24,640.
OFFICE SUPPLIES AND EXPENSES	4,031.
Subtotal	32,380.

Continued on next page Statement 8

SCANA CORPORATION 57-0784499

1120 Page 1 Detail

Line 26 - Other Deductions (Cont'd)

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

Amortization	147,348.
Travel, Meals and Entertainment	137,245.
INJURIES AND DAMAGES	1,352,006.
INSURANCE	592,872.
MERCHANDISING EXPENSES	2,130,960.
MISCELLANEOUS DEDUCTIONS	1,803,559.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	17,596,053.
OFFICE SUPPLIES AND EXPENSES	7,790,943.
OUTSIDE SERVICES	2,462,139.
Subtotal	34,013,125.

CLEAN ENERGY ENTERPRISES INC

OFFICE SUPPLIES AND EXPENSES	703.
Subtotal	703.

ELIMINATIONS SCANA CORPORATIO

INJURIES AND DAMAGES	-5,113,014.
INSURANCE	-139,629.
MERCHANDISING EXPENSES	-1,478,536.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	-35,176,019.
OFFICE SUPPLIES AND EXPENSES	-37,231,910.
OUTSIDE SERVICES	-27,195,321.
SELLING EXPENSES	19,408.
Subtotal	-106,315,021.

Total Line 26 - Other Deductions	923,309,629.

SCANA CORPORATION 57-0784499

Form 1120, Page 1 Detail

Non-SRLY NOL Carryover Schedule

SCANA CORPORATION

Year Ending	Original NOL	Amount Available	Amount Used in Current Year	Converted Contributions	Carryover to Next Year
12/31/1997					
12/31/1998					
12/31/1999					
12/31/2000					
12/31/2001					
12/31/2002					
12/31/2003					
12/31/2004					
12/31/2005					
12/31/2006					
12/31/2007					
12/31/2008					
12/31/2009					
12/31/2010					
12/31/2011					
12/31/2012					
12/31/2013					
12/31/2014					
12/31/2015					
12/31/2016	62,862,156.	62,862,156.			62,862,156.
Total	62,862,156.	62,862,156.			62,862,156.

SCANA CORPORATION 57-0784499

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Consolidated Schedules				
Sch. C Summary				
Dividends				
1 Domestic Corps-subj. to 70% ded	303,143.			303,143.
2 Domestic Corps-subj.to 80% ded				
3 Debt-Financed stock - Dom & Fgn				
4 Pref Stk < 20% owned Pub Util				
5 Pref Stk >= 20% owned Pub Util				
6 <20% Fgn Corps & FSC's-70%				
7 >= 20% Fgn Corps & FSC's-80%				
8 Wholly-owned fgn subs-100%				
10 Domestic corps-Small Bus Inv				
11 From affiliated group member				
12 From certain FSCs				
13 Foreign corps not incl. above	34,349.			34,349.
14 Controlled fgn groups under Subpart F				
15 Foreign Dividend Gross-up				
16 IC-DISC and former DISC Div not included above				
17 Other dividends				
19 TOTAL DIVIDENDS	337,492.			337,492.
Special Deductions				
1 Domestic Corp-subj. to 70% ded	212,200.			212,200.
2 Domestic Corp-subj. to 80% ded				
3 Debt-Financed stock-Dom & Fgn				
4 Pref Stk < 20% owned Pub Util				
5 Pref Stk >= 20% owned Pub Util				
6 <20% Fgn Corps & FSC's-70%				
7 >= 20% Fgn Corps & FSC's-80%				
8 Wholly-owned fgn subs-100%				
9 Total Lines 1-8	212,200.			212,200.
10 Domestic corps-Small Bus Inv				
11 From affiliated group member				
12 From certain FSCs				
18 Deduction for Div Paid on Pref Stock of Public Utilities				
20 TOTAL SPECIAL DEDUCTIONS	212,200.			212,200.

SCANA CORPORATION 57-0784499

Consolidated Schedules
Sch. C Summary

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	57-0850977	57-1007394	56-2128483
Dividends								
1 Domestic Corps-subj. to 70% ded	303,143.							
2 Domestic Corps-subj.to 80% ded								
3 Debt-Financed stock - Dom & Fgn								
4 Pref Stk < 20% owned Pub Util								
5 Pref Stk >= 20% owned Pub Util								
6 <20% Fgn Corps & FSC's-70%								
7 >=20% Fgn Corps & FSC's-80%								
8 Wholly-owned fgn subs-100%								
10 Domestic corps-Small Bus Inv								
11 From affiliated group member								
12 From certain FSCs								
13 Foreign corps not incl. above	34,349.							
14 Controlled fgn groups under Subpart F								
15 Foreign Dividend Gross-up								
16 IC-DISC and former DISC Div not included above								
17 Other dividends								
19 TOTAL DIVIDENDS	337,492.							
Special Deductions								
1 Domestic Corp-subj. to 70% ded	212,200.							
2 Domestic Corp-subj. to 80% ded								
3 Debt-Financed stock-Dom & Fgn								
4 Pref Stk < 20% owned Pub Util								
5 Pref Stk >= 20% owned Pub Util								
6 <20% Fgn Corps & FSC's-70%								
7 >=20% Fgn Corps & FSC's-80%								
8 Wholly-owned fgn subs-100%								
9 Total Lines 1-8	212,200.							
10 Domestic corps-Small Bus Inv								
11 From affiliated group member								
12 From certain FSCs								
18 Deduction for Div Paid on Pref Stock of Public Utilities								
20 TOTAL SPECIAL DEDUCTIONS	212,200.							

SCANA CORPORATION 57-0784499

Consolidated Schedules Sch. C Summary	CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
Dividends		
1 Domestic Corps-subj. to 70% ded		
2 Domestic Corps-subj.to 80% ded		
3 Debt-Financed stock - Dom & Fgn		
4 Pref Stk < 20% owned Pub Util		
5 Pref Stk > = 20% owned Pub Util		
6 <20% Fgn Corps & FSC's-70%		
7 >=20% Fgn Corps & FSC's-80%		
8 Wholly-owned fgn subs-100%		
10 Domestic corps-Small Bus Inv		
11 From affiliated group member		
12 From certain FSCs		
13 Foreign corps not incl. above		
14 Controlled fgn groups under Subpart F		
15 Foreign Dividend Gross-up		
16 IC-DISC and former DISC Div not included above		
17 Other dividends		
19 TOTAL DIVIDENDS		
Special Deductions		
1 Domestic Corp-subj. to 70% ded		
2 Domestic Corp-subj. to 80% ded		
3 Debt-Financed stock-Dom & Fgn		
4 Pref Stk <20% owned Pub Util		
5 Pref Stk >= 20% owned Pub Util		
6 <20% Fgn Corps & FSC's-70%		
7 >=20% Fgn Corps & FSC's-80%		
8 Wholly-owned fgn subs-100%		
9 Total Lines 1-8		
10 Domestic corps-Small Bus Inv		
11 From affiliated group member		
12 From certain FSCs		
18 Deduction for Div Paid on Pref Stock of Public Utilities		
20 TOTAL SPECIAL DEDUCTIONS		

Form 1120, Page 4 Detail

Schedule K, Line 5b

Name of Entity	EIN	Country of Incorporation	Max Percentage Owned in Profit, Loss, or Capital
SCANA CORPORATION			
CANADYS REFINED COAL LLC	27-1302931	US	40.000
APOG LLC	26-0468152	US	25.000
CARDINAL PIPELINE COMPANY LLC	76-0489410	US	33.200
MAGNOLIA HOLDING COMPANY LLC	73-1665109	US	22.601

SCANA CORPORATION 57-0784499

Consolidated Schedules

Sch. L - Beginning

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
	Assets				
1	Cash	233,257,854.			233,257,854.
2 a	Trade Notes and A/R	682,391,843.			682,391,843.
b	Less allowance for Bad Debts	5,269,711.			5,269,711.
3	Inventories	311,778,910.			311,778,910.
4	US Government Obligations				
5	Tax-exempt Securities				
6	Other Current Assets	434,193,743.	-282,411,660.		151,782,083.
7	Loans to Stockholders				
8	Mtge and Real Estate Loans				
9	Other Investments	6,337,891,778.	-6,127,305,346.		210,586,432.
10 a	Buildings and Other Depreciable Assets	18,667,897,661.			18,667,897,661.
b	Less Accum. Depreciation	5,975,136,607.			5,975,136,607.
11 a	Depletable Assets				
b	Less Accum. Depletion				
12	Land (net of any Amortization)				
13 a	Intangible Assets				
b	Less Accum. Amortization				
14	Other Assets	2,787,910,362.	-308,438,712.		2,479,471,650.
15	Total Assets	23,474,915,833.	-6,718,155,718.		16,756,760,115.
	Liabilities and Stockholders' Equity				
16	Accounts Payable	576,642,625.			576,642,625.
17	Mtges, Notes, Bond Payable in less than 1 year	647,291,449.			647,291,449.
18	Other Current Liabilities	933,051,858.	-282,411,661.		650,640,197.
19	Loans from Stockholders				
20	Mtges, Notes, Bonds Payable in 1 year or more	5,904,834,401.			5,904,834,401.
21	Other Liabilities	3,991,397,098.	-442,218,711.		3,549,178,387.
22 a	Capital stock-Preferred	100,000.	-100,000.		
b	Capital stock-Common	3,013,984,622.	-596,411,122.		2,417,573,500.
23	Additional Paid-in Capital	2,905,495,009.	-2,922,001,429.		-16,506,420.
24	Retained earnings-Appropriated				
25	Retained earnings-Unappropriated	5,594,564,883.	-2,490,250,595.		3,104,314,288.
26	Adjustments to shareholders' equity	-80,653,603.	15,237,800.		-65,415,803.
27	Less cost of Treasury Stock	11,792,509.			11,792,509.
28	Total Liabilities and Stockholders' Equity	23,474,915,833.	-6,718,155,718.		16,756,760,115.

SCANA CORPORATION

57-0784499

Consolidated Schedules

Sch. L - Beginning

		SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
		57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	57-0850977	57-1007394	56-2128483
	Assets								
1	Cash	75,472,099.	42,487,869.	110,056,888.	-16,249,285.	11,512,507.	7,619,603.	1,155,256.	1,182,034.
2 a	Trade Notes and A/R		2,183,365.	521,796,470.		343,264.	94,110,229.		63,958,515.
b	Less allowance for Bad Debts			2,964,230.			1,673,736.		631,745.
3	Inventories		287,791.	171,415,921.	38,266,358.	24,000,296.	25,425,070.		52,383,474.
4	US Government Obligations								
5	Tax-exempt Securities								
6	Other Current Assets	136,985,242.	97,066,455.	106,231,635.	4,610,220.	34,172,067.	50,185,730.	1,000,147.	3,941,247.
7	Loans to Stockholders								
8	Mtge and Real Estate Loans								
9	Other Investments	6,168,405,052.		171,160,735.			2,618.		-1,676,627.
10 a	Buildings and Other Depreciable Assets		307,577,019.	14,615,659,537.	995,863,172.	702,081,252.	26,452,408.		2,020,264,273.
b	Less Accum. Depreciation		100,412,477.	4,150,427,302.	786,794,669.	238,603,058.	22,440,948.		676,458,153.
11 a	Depletable Assets								
b	Less Accum. Depletion								
12	Land (net of any Amortization)								
13 a	Intangible Assets								
b	Less Accum. Amortization								
14	Other Assets	371,434,886.	19,937,330.	2,183,067,690.	836,823.	47,670,033.	20,746,682.	454,900.	143,762,018.
15	Total Assets	6,752,297,279.	369,127,352.	13,725,997,344.	236,532,619.	581,176,361.	200,427,656.	2,610,303.	1,606,725,036.
	Liabilities and Stockholders' Equity								
16	Accounts Payable	112,256.	67,629,087.	392,595,365.	20,640,493.	14,756,884.	57,712,087.		23,196,453.
17	Mtges, Notes, Bond Payable in less than 1 year	41,760,000.	465,154.	303,880,566.	220,125,000.	6,666,667.			74,394,062.
18	Other Current Liabilities	-20,892,898.	123,856,804.	714,065,721.	-6,929,100.	58,729,004.	35,585,033.	-10,684.	28,648,006.
19	Loans from Stockholders								
20	Mtges, Notes, Bonds Payable in 1 year or more	879,200,000.	1.	4,429,036,067.		246,598,333.			350,000,000.
21	Other Liabilities	409,986,459.	170,325,390.	2,863,381,719.		128,417,123.	26,014,334.	1,376,485.	391,892,411.
22 a	Capital stock-Preferred			100,000.					
b	Capital stock-Common	2,417,575,500.	1,000.	576,405,122.	1,000.	20,000,000.	1,000.	1,000.	-3,000.
23	Additional Paid-in Capital	-9,030,772.	6,849,916.	2,183,832,337.	2,695,226.	32,307,572.	45,455,110.	10,025,666.	633,359,516.
24	Retained earnings-Appropriated								
25	Retained earnings-Unappropriated	3,111,012,466.		2,265,470,450.		73,707,400.	46,380,846.	-8,580,838.	106,559,263.
26	Adjustments to shareholders' equity	-65,633,223.		-2,770,003.		-6,622.	-10,720,754.	-201,326.	-1,321,675.
27	Less cost of Treasury Stock	11,792,509.							
28	Total Liabilities and Stockholders' Equity	6,752,297,279.	369,127,352.	13,725,997,344.	236,532,619.	581,176,361.	200,427,656.	2,610,303.	1,606,725,036.

SCANA CORPORATION 57-0784499

Consolidated Schedules
Sch. L - Beginning

Assets		CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
1	Cash	20,883.	
2 a	Trade Notes and A/R		
b	Less allowance for Bad Debts		
3	Inventories		
4	US Government Obligations		
5	Tax-exempt Securities		
6	Other Current Assets		1,000.
7	Loans to Stockholders		
8	Mtge and Real Estate Loans		
9	Other Investments		
10 a	Buildings and Other Depreciable Assets		
b	Less Accum. Depreciation		
11 a	Depletable Assets		
b	Less Accum. Depletion		
12	Land (net of any Amortization)		
13 a	Intangible Assets		
b	Less Accum. Amortization		
14	Other Assets		
15	Total Assets	20,883.	1,000.
Liabilities and Stockholders' Equity			
16	Accounts Payable		
17	Mtges, Notes, Bond Payable in less than 1 year		
18	Other Current Liabilities	-28.	
19	Loans from Stockholders		
20	Mtges, Notes, Bonds Payable in 1 year or more		
21	Other Liabilities	3,177.	
22 a	Capital stock-Preferred		
b	Capital stock-Common	2,000.	1,000.
23	Additional Paid-in Capital	438.	
24	Retained earnings-Appropriated		
25	Retained earnings-Unappropriated	15,296.	
26	Adjustments to shareholders' equity		
27	Less cost of Treasury Stock		
28	Total Liabilities and Stockholders' Equity	20,883.	1,000.

SCANA CORPORATION 57-0784499

Consolidated Schedules
Sch. L - Ending

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
	Assets				
1	Cash	251,179,428.	-45,182,686.		205,996,742.
2 a	Trade Notes and A/R	828,058,874.	-94,874,493.		733,184,381.
b	Less allowance for Bad Debts	5,853,608.			5,853,608.
3	Inventories	290,480,845.			290,480,845.
4	US Government Obligations				
5	Tax-exempt Securities				
6	Other Current Assets	386,111,560.	-105,742,210.		280,369,350.
7	Loans to Stockholders				
8	Mtge and Real Estate Loans				
9	Other Investments	6,692,703,961.	-6,521,839,642.		170,864,319.
10 a	Buildings and Other Depreciable Assets	20,053,878,140.	1,079,817.		20,054,957,957.
b	Less Accum. Depreciation	6,207,830,938.	-753,558,215.		5,454,272,723.
11 a	Depletable Assets				
b	Less Accum. Depletion				
12	Land (net of any Amortization)				
13 a	Intangible Assets				
b	Less Accum. Amortization				
14	Other Assets	3,237,378,959.	-835,956,050.		2,401,422,909.
15	Total Assets	25,526,107,221.	-6,848,957,049.		18,677,150,172.
	Liabilities and Stockholders' Equity				
16	Accounts Payable	388,631,752.	-577.		388,631,175.
17	Mtges, Notes, Bond Payable in less than 1 year	957,426,831.			957,426,831.
18	Other Current Liabilities	1,150,543,273.	-433,993,990.		716,549,283.
19	Loans from Stockholders				
20	Mtges, Notes, Bonds Payable in 1 year or more	6,493,747,509.	-20,819,448.		6,472,928,061.
21	Other Liabilities	4,482,612,363.	-51,862,966.		4,430,749,397.
22 a	Capital stock-Preferred	100,000.	-100,000.		
b	Capital stock-Common	3,013,983,622.	-596,410,122.		2,417,573,500.
23	Additional Paid-in Capital	2,989,576,451.	-3,006,082,871.		-16,506,420.
24	Retained earnings-Appropriated				
25	Retained earnings-Unappropriated	6,115,989,734.	-2,744,662,271.		3,371,327,463.
26	Adjustments to Shareholders' Equity	-54,028,781.	4,975,196.		-49,053,585.
27	Less cost of Treasury Stock	12,475,533.			12,475,533.
28	Total Liabilities and Stockholders' Equity	25,526,107,221.	-6,848,957,049.		18,677,150,172.

SCANA CORPORATION 57-0784499

Consolidated Schedules

Sch. L - Ending

		SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
		57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	57-0850977	57-1007394	56-2128483
	Assets								
1	Cash	67,880,818.	51,056,258.	112,818,510.	-5,463,007.	10,748,110.	5,526,693.		8,591,163.
2 a	Trade Notes and A/R	89,024,551.	2,096,127.	514,133,020.		55,149.	122,704,581.		100,045,446.
b	Less allowance for Bad Debts			3,239,931.			2,081,935.		531,742.
3	Inventories		349,994.	172,900,770.	27,381,245.	25,835,508.	24,739,139.		39,274,189.
4	US Government Obligations								
5	Tax-exempt Securities								
6	Other Current Assets	120,478,566.	75,843,476.	91,205,043.	749,859.	32,306,162.	61,452,576.		4,074,878.
7	Loans to Stockholders								
8	Mtge and Real Estate Loans								
9	Other Investments	6,512,206,010.		180,487,957.			3,119.		6,875.
10 a	Buildings and Other Depreciable Assets		315,790,274.	15,686,426,272.	1,114,511,261.	707,077,289.	27,985,070.		2,202,087,974.
b	Less Accum. Depreciation		113,944,461.	4,272,332,560.	843,261,889.	249,525,438.	23,472,017.		705,294,573.
11 a	Depletable Assets								
b	Less Accum. Depletion								
12	Land (net of any Amortization)								
13 a	Intangible Assets								
b	Less Accum. Amortization								
14	Other Assets	440,317,704.	28,308,920.	2,536,656,672.	4,007,795.	48,206,224.	13,458,430.		166,423,214.
15	Total Assets	7,229,907,649.	359,500,588.	15,019,055,753.	297,925,264.	574,703,004.	230,315,656.		1,814,677,424.
	Liabilities and Stockholders' Equity								
16	Accounts Payable	110,781.	51,824,886.	198,630,173.	10,140,208.	10,808,069.	77,159,475.		39,958,160.
17	Mtges, Notes, Bond Payable in less than 1 year	68,800,000.	478,061.	525,461,103.	284,221,000.	6,666,667.			71,800,000.
18	Other Current Liabilities	91,482,330.	134,166,166.	796,820,781.	867,830.	51,317,156.	35,303,081.		40,565,474.
19	Loans from Stockholders								
20	Mtges, Notes, Bonds Payable in 1 year or more	874,800,000.		4,929,015,843.		239,931,666.			450,000,000.
21	Other Liabilities	471,027,096.	166,180,559.	3,230,551,722.		134,456,396.	32,087,426.		448,304,284.
22 a	Capital stock-Preferred			100,000.					
b	Capital stock-Common	2,417,575,500.	1,000.	576,405,122.	1,000.	20,000,000.	1,000.		-3,000.
23	Additional Paid-in Capital	-14,923,664.	6,849,916.	2,283,832,337.	2,695,226.	32,307,572.	45,455,110.		633,359,516.
24	Retained earnings-Appropriated								
25	Retained earnings-Unappropriated	3,382,283,456.		2,481,211,937.		79,222,288.	41,094,100.		132,184,843.
26	Adjustments to Shareholders' Equity	-48,772,317.		-2,973,265.		-6,810.	-784,536.		-1,491,853.
27	Less cost of Treasury Stock	12,475,533.							
28	Total Liabilities and Stockholders' Equity	7,229,907,649.	359,500,588.	15,019,055,753.	297,925,264.	574,703,004.	230,315,656.		1,814,677,424.

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SCANA CORPORATION 57-0784499

Consolidated Schedules
Sch. L - Ending

		CLEAN ENERGY ENTERPRISES INC	SCANA CORPORATE SECURITY SERVICES INC
		56-1078443	20-0989017
	Assets		
1	Cash	20,883.	
2 a	Trade Notes and A/R		
b	Less allowance for Bad Debts		
3	Inventories		
4	US Government Obligations		
5	Tax-exempt Securities		
6	Other Current Assets		1,000.
7	Loans to Stockholders		
8	Mtge and Real Estate Loans		
9	Other Investments		
10 a	Buildings and Other Depreciable Assets		
b	Less Accum. Depreciation		
11 a	Depletable Assets		
b	Less Accum. Depletion		
12	Land (net of any Amortization)		
13 a	Intangible Assets		
b	Less Accum. Amortization		
14	Other Assets		
15	Total Assets	20,883.	1,000.
	Liabilities and Stockholders' Equity		
16	Accounts Payable		
17	Mtges, Notes, Bond Payable in less than 1 year		
18	Other Current Liabilities	20,455.	
19	Loans from Stockholders		
20	Mtges, Notes, Bonds Payable in 1 year or more		
21	Other Liabilities	4,880.	
22 a	Capital stock-Preferred		
b	Capital stock-Common	2,000.	1,000.
23	Additional Paid-in Capital	438.	
24	Retained earnings-Appropriated		
25	Retained earnings-Unappropriated	-6,890.	
26	Adjustments to Shareholders' Equity		
27	Less cost of Treasury Stock		
28	Total Liabilities and Stockholders' Equity	20,883.	1,000.

SCANA CORPORATION 57-0784499

Form 1120 Page 5 Detail, Sch. L

	Beginning	Ending
Line 6 - Other Current Assets		
SCANA CORPORATION		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	136,320,822.	120,009,610.
INTEREST AND DIVIDENDS RECEIVABLE	175,271.	1,449.
PREPAYMENTS	489,149.	467,507.
Subtotal	136,985,242.	120,478,566.
SCANA SERVICES INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	87,390,001.	65,319,345.
PREPAYMENTS	9,676,454.	10,524,131.
Subtotal	97,066,455.	75,843,476.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	13,994,351.	4,731,796.
INTEREST AND DIVIDENDS RECEIVABLE		121,727.
OTHER CURRENT ASSETS	10,356,905.	
PREPAYMENTS	81,880,379.	86,351,520.
Subtotal	106,231,635.	91,205,043.
SOUTH CAROLINA FUEL CO INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	4,013,064.	72,277.
PREPAYMENTS	597,156.	677,582.
Subtotal	4,610,220.	749,859.
SC GENERATING COMPANY INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	33,277,567.	31,405,850.
PREPAYMENTS	894,500.	900,312.
Subtotal	34,172,067.	32,306,162.

Continued on next page Statement 21

SCANA CORPORATION 57-0784499

Form 1120 Page 5 Detail, Sch. L

	Beginning	Ending
Line 6 - Other Current Assets (Cont'd)		
SCANA ENERGY MARKETING INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	23,765,369.	54,155,067.
OTHER CURRENT ASSETS	24,306,527.	2,663,111.
PREPAYMENTS	2,113,834.	4,634,398.
Subtotal	50,185,730.	61,452,576.
SERVICECARE INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	1,000,147.	
Subtotal	1,000,147.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	1,683,501.	
OTHER CURRENT ASSETS	698,330.	2,633,110.
PREPAYMENTS	1,559,416.	1,441,768.
Subtotal	3,941,247.	4,074,878.
SCANA CORPORATE SECURITY SERVICES INC		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	1,000.	1,000.
Subtotal	1,000.	1,000.
ELIMINATIONS SCANA CORPORATIO		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	-282,411,660.	-259,717,380.
OTHER CURRENT ASSETS		153,975,170.
Subtotal	-282,411,660.	-105,742,210.
Total Line 6 - Other Current Assets	151,782,083.	280,369,350.

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	Beginning	Ending
Line 9 - Other Investments		
SCANA CORPORATION		
INVEST IN ASSOC COMPANIES	6,127,511,084.	6,469,026,775.
INVESTMENT IN PARTNERSHIPS	708.	
OTHER INVESTMENTS	40,004,701.	43,490,676.
INVESTMENT IN SUBSIDIARIES	888,559.	-311,441.
Subtotal	6,168,405,052.	6,512,206,010.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
INVEST IN ASSOC COMPANIES		2,856,381.
OTHER INVESTMENTS	171,160,735.	177,631,576.
Subtotal	171,160,735.	180,487,957.
SCANA ENERGY MARKETING INC		
INVESTMENTS IN STOCK	2,618.	3,119.
Subtotal	2,618.	3,119.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
INVEST IN ASSOC COMPANIES	-4,082,101.	
OTHER INVESTMENTS	2,405,474.	6,875.
Subtotal	-1,676,627.	6,875.
ELIMINATIONS SCANA CORPORATIO		
INVEST IN ASSOC COMPANIES	-6,127,305,346.	-6,469,305,068.
OTHER INVESTMENTS		-52,534,574.
Subtotal	-6,127,305,346.	-6,521,839,642.
Total Line 9 - Other Investments	210,586,432.	170,864,319.

SCANA CORPORATION 57-0784499

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	Beginning	Ending
Line 14 - Other Assets		
SCANA CORPORATION		
ACC DEFERRED INCOME TAXES	58,734,712.	75,817,124.
DUE FROM AFFIL DIRECTORS ENDOWMENT	3,754,099.	3,908,222.
DUE FROM AFFILIATES	304,013,275.	356,540,764.
MISC DEFERRED DEBITS	1,174,677.	932,212.
UNAMORTIZED DEBT EXPENSE	3,758,123.	3,119,382.
Subtotal	371,434,886.	440,317,704.
SCANA SERVICES INC		
ACC DEFERRED INCOME TAXES	13,669,800.	19,221,300.
CLEARING ACCOUNTS	48,485.	217,289.
MISC DEFERRED DEBITS	6,219,045.	8,870,331.
Subtotal	19,937,330.	28,308,920.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACC DEFERRED INCOME TAXES	277,332,298.	354,286,724.
CLEARING ACCOUNTS	4,232.	418,919.
DUE FROM AFFIL DIRECTORS ENDOWMENT	382,447.	379,524.
MISC DEFERRED DEBITS	82,102,622.	163,564,671.
PRELIM SURVEY AND INVEST CHGS	198,470.	322,402.
REGULATORY ASSET - FASB 109	1,775,528,967.	1,967,097,185.
UNAMORTIZED DEBT EXPENSE	31,259,888.	35,470,866.
UNAMORTIZED LOSS ON REACQ DEBT	16,258,766.	15,116,381.
Subtotal	2,183,067,690.	2,536,656,672.
SOUTH CAROLINA FUEL CO INC		
ACC DEFERRED INCOME TAXES	-1,307,100.	2,411,500.
MISC DEFERRED DEBITS	2,143,923.	1,596,295.
Subtotal	836,823.	4,007,795.

Continued on next page Statement 24

SCANA CORPORATION 57-0784499

Form 1120 Page 5 Detail, Sch. L

	Beginning	Ending
Line 14 - Other Assets (Cont'd)		
SC GENERATING COMPANY INC		
ACC DEFERRED INCOME TAXES	6,005,900.	6,312,000.
CLEARING ACCOUNTS		1.
MISC DEFERRED DEBITS	1,718,750.	3,106,389.
REGULATORY ASSET - FASB 109	39,429,748.	38,334,875.
UNAMORTIZED DEBT EXPENSE	515,635.	452,959.
Subtotal	47,670,033.	48,206,224.
SCANA ENERGY MARKETING INC		
ACC DEFERRED INCOME TAXES	14,748,800.	11,617,800.
CLEARING ACCOUNTS	-290.	20.
MISC DEFERRED DEBITS	5,998,172.	1,840,610.
Subtotal	20,746,682.	13,458,430.
SERVICECARE INC		
ACC DEFERRED INCOME TAXES	454,900.	
Subtotal	454,900.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACC DEFERRED INCOME TAXES	28,922,800.	31,970,300.
CLEARING ACCOUNTS	-1.	
DUE FROM AFFIL DIRECTORS ENDOWMENT	59,371.	58,950.
MISC DEFERRED DEBITS	1,480,223.	539,079.
REGULATORY ASSET - FASB 109	112,676,197.	132,879,041.
UNAMORTIZED DEBT EXPENSE	623,428.	975,844.
Subtotal	143,762,018.	166,423,214.
ELIMINATIONS SCANA CORPORATIO		
DUE FROM AFFIL DIRECTORS ENDOWMENT	-4,195,917.	-4,346,696.
DUE FROM AFFILIATES	-304,011,966.	-356,539,453.
MISC DEFERRED DEBITS	-230,829.	-475,069,901.

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	Beginning	Ending
Line 14 - Other Assets (Cont'd)		
Subtotal	-308,438,712.	-835,956,050.
Total Line 14 - Other Assets	2,479,471,650.	2,401,422,909.

SCANA CORPORATION 57-0784499

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	Beginning	Ending
Line 18 - Other Current Liabilities		
SCANA CORPORATION		
ACCRUED INTEREST PAYABLE	10,408,385.	10,391,508.
ACCRUED TAXES PAY - FEDERAL INCOME	-92,586,368.	-9,316,753.
ACCRUED TAXES PAY - STATE INCOME	-23,670,685.	1,946,908.
ACCTS PAYABLE - ASSOC COS	1,000.	1,000.
DIVIDENDS DECLARED	77,889,720.	82,177,227.
MISC CURRENT AND ACCRUED LIABILITIE	7,064,895.	6,282,440.
TAXES PAYABLE - SALES AND USE	155.	
Subtotal	-20,892,898.	91,482,330.
SCANA SERVICES INC		
ACCRUED INTEREST PAYABLE	1,997,877.	1,901,664.
ACCRUED TAXES PAY - FEDERAL INCOME	5,305,200.	3,657,500.
ACCRUED TAXES PAY - STATE INCOME	541,000.	848,600.
ACCRUED TAXES PAYABLE - OTHER	3,225,485.	3,786,070.
ACCTS PAYABLE - ASSOC COS	75,857,946.	74,347,946.
MISC CURRENT AND ACCRUED LIABILITIE	35,904,727.	48,633,766.
TAXES PAYABLE - OTHER	935,516.	936,716.
TAXES PAYABLE - SALES AND USE	89,053.	53,904.
Subtotal	123,856,804.	134,166,166.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACCRUED INTEREST PAYABLE	64,981,071.	66,073,421.
ACCRUED TAXES PAY - FEDERAL INCOME	139,536,235.	176,366,709.
ACCRUED TAXES PAY - STATE INCOME	31,166,055.	76,470,800.
ACCRUED TAXES PAYABLE - OTHER	173,595,618.	190,023,235.
ACCTS PAYABLE - ASSOC COS	71,894,901.	61,294,130.
CUSTOMER DEPOSITS	57,087,060.	60,283,425.
DIVIDENDS DECLARED	72,300,000.	77,500,000.
MISC CURRENT AND ACCRUED LIABILITIE	94,969,814.	80,313,106.
TAXES PAYABLE - OTHER	1,882,026.	1,970,592.
TAXES PAYABLE - SALES AND USE	6,652,941.	6,525,363.
Subtotal	714,065,721.	796,820,781.

Continued on next page

SCANA CORPORATION 57-0784499

Form 1120 Page 5 Detail, Sch. L

	Beginning	Ending
Line 18 - Other Current Liabilities (Cont'd)		
SOUTH CAROLINA FUEL CO INC		
ACCRUED INTEREST PAYABLE		2,431.
ACCRUED TAXES PAY - FEDERAL INCOME	-6,023,400.	538,099.
ACCRUED TAXES PAY - STATE INCOME	-905,700.	327,300.
Subtotal	-6,929,100.	867,830.
SC GENERATING COMPANY INC		
ACCRUED INTEREST PAYABLE	1,480,680.	1,414,749.
ACCRUED TAXES PAY - FEDERAL INCOME	860,180.	-850,210.
ACCRUED TAXES PAY - STATE INCOME	65,800.	161,000.
ACCRUED TAXES PAYABLE - OTHER	4,176,081.	4,985,039.
ACCTS PAYABLE - ASSOC COS	48,717,513.	43,021,488.
DIVIDENDS DECLARED	2,235,000.	1,560,000.
MISC CURRENT AND ACCRUED LIABILITIE	1,189,649.	1,026,395.
TAXES PAYABLE - SALES AND USE	4,101.	-1,305.
Subtotal	58,729,004.	51,317,156.
SCANA ENERGY MARKETING INC		
ACCRUED INTEREST PAYABLE	11,712.	33,415.
ACCRUED TAXES PAY - FEDERAL INCOME	-3,892,700.	4,634,200.
ACCRUED TAXES PAY - STATE INCOME	-2,475,357.	-1,128,633.
ACCRUED TAXES PAYABLE - OTHER	94,486.	83,856.
ACCTS PAYABLE - ASSOC COS	4,482,040.	439,780.
CUSTOMER DEPOSITS	10,857,077.	10,531,966.
DIVIDENDS DECLARED	3,250,000.	3,550,000.
MISC CURRENT AND ACCRUED LIABILITIE	20,389,595.	13,972,016.
TAXES PAYABLE - OTHER	49,753.	142,988.
TAXES PAYABLE - SALES AND USE	2,818,427.	3,043,493.
Subtotal	35,585,033.	35,303,081.
SERVICECARE INC		
ACCRUED TAXES PAY - FEDERAL INCOME	-9,200.	
ACCRUED TAXES PAY - STATE INCOME	-1,600.	
ACCTS PAYABLE - ASSOC COS	116.	

Continued on next page

SCANA CORPORATION 57-0784499

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	Beginning	Ending
Line 18 - Other Current Liabilities (Cont'd)		
Subtotal	-10,684.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACCRUED INTEREST PAYABLE	6,203,120.	6,395,626.
ACCRUED TAXES PAY - FEDERAL INCOME	-15,101,798.	-235,147.
ACCRUED TAXES PAY - STATE INCOME	-113,005.	-1,543,756.
ACCRUED TAXES PAYABLE - OTHER	278,766.	2,463,321.
ACCTS PAYABLE - ASSOC COS	5,804,421.	5,629,799.
CUSTOMER DEPOSITS	8,282,424.	7,553,872.
DIVIDENDS DECLARED	7,400,000.	5,188,117.
MISC CURRENT AND ACCRUED LIABILITIE	15,409,894.	14,674,459.
TAXES PAYABLE - OTHER	412,839.	398,186.
TAXES PAYABLE - SALES AND USE	71,345.	40,997.
Subtotal	28,648,006.	40,565,474.
CLEAN ENERGY ENTERPRISES INC		
ACCRUED TAXES PAY - FEDERAL INCOME		-400.
ACCRUED TAXES PAY - STATE INCOME	-18.	-18.
ACCRUED TAXES PAYABLE - OTHER	-10.	-10.
DIVIDENDS DECLARED		20,883.
Subtotal	-28.	20,455.
ELIMINATIONS SCANA CORPORATIO		
ACCRUED INTEREST PAYABLE	-1,997,877.	-1,901,664.
ACCTS PAYABLE - ASSOC COS	-195,228,784.	-168,655,716.
DIVIDENDS DECLARED	-85,185,000.	-89,160,000.
MISC CURRENT AND ACCRUED LIABILITIE		-174,276,610.
Subtotal	-282,411,661.	-433,993,990.
Total Line 18 - Other Current Liabilities	650,640,197.	716,549,283.

SCANA CORPORATION 57-0784499

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	Beginning	Ending
Line 21 - Other Liabilities		
SCANA CORPORATION		
ACC DEF FED INCOME TAX	-2,558,900.	-2,195,600.
ACC DEF STATE INCOME TAX	-384,700.	-330,100.
DEFERRED CREDITS - OTHER	76,554,360.	77,243,718.
DUE TO AFFILIATES	441,818.	438,474.
INJURIES AND DAMAGES RESERVE	10,702,473.	12,215,735.
POST RETIREMENT BENEFITS	327,334,566.	385,414,130.
UNAMORT DISCT - LT DEBT	-2,103,158.	-1,759,261.
Subtotal	409,986,459.	471,027,096.
SCANA SERVICES INC		
ACC DEF FED INCOME TAX	16,467,400.	16,229,000.
ACC DEF STATE INCOME TAX	2,112,000.	1,989,200.
DEFERRED CREDITS - OTHER	17,232,482.	20,159,841.
DUE TO AFFILIATES	133,780,000.	127,025,000.
INJURIES AND DAMAGES RESERVE	255,447.	777,518.
OBLIGATIONS UNDER CAP LEASE	478,061.	
Subtotal	170,325,390.	166,180,559.
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
ACC DEF FED INCOME TAX	1,692,572,092.	1,883,853,155.
ACC DEF STATE INCOME TAX	217,942,117.	241,044,075.
ACCUM DEF INVEST TAX CREDITS	23,580,500.	22,188,300.
DEFERRED CREDITS - OTHER	73,571,854.	49,074,144.
DUE TO AFFILIATES	212,184,657.	257,285,183.
FASB 109 REGULATORY LIABILITY	147,243,710.	238,854,458.
INJURIES AND DAMAGES RESERVE	5,355,089.	7,859,531.
OBLIGATIONS UNDER CAP LEASE	12,477,819.	20,678,011.
OTHER ASSET RETIREMENT OBLIGATIONS	476,223,696.	509,434,012.
UNAMORT DISCT - LT DEBT	2,230,185.	280,853.
Subtotal	2,863,381,719.	3,230,551,722.
SC GENERATING COMPANY INC		
ACC DEF FED INCOME TAX	89,978,500.	95,303,300.
ACC DEF STATE INCOME TAX	13,772,400.	14,517,600.
ACCUM DEF INVEST TAX CREDITS	1,970,709.	1,740,369.
DEFERRED CREDITS - OTHER	8,952,513.	8,099,452.
DUE TO AFFILIATES	653,122.	904,166.

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SCANA CORPORATION 57-0784499

Form 1120 Page 5 Detail, Sch. L

	Beginning	Ending
Line 21 - Other Liabilities (Cont'd)		
FASB 109 REGULATORY LIABILITY	1,220,600.	1,078,000.
INJURIES AND DAMAGES RESERVE	132,848.	111,940.
OTHER ASSET RETIREMENT OBLIGATIONS	11,736,431.	12,701,569.
Subtotal	128,417,123.	134,456,396.
SCANA ENERGY MARKETING INC		
ACC DEF FED INCOME TAX	-536,400.	2,474,800.
ACC DEF STATE INCOME TAX	-91,500.	335,900.
DEFERRED CREDITS - OTHER	6,529,856.	6,876,324.
DUE TO AFFILIATES	20,112,378.	22,400,402.
Subtotal	26,014,334.	32,087,426.
SERVICECARE INC		
ACC DEF FED INCOME TAX	-106,200.	
ACC DEF STATE INCOME TAX	-16,000.	
DUE TO AFFILIATES	1,498,685.	
Subtotal	1,376,485.	
PUBLIC SERVICE COMPANY OF NORTH CAROLINA		
ACC DEF FED INCOME TAX	238,639,500.	289,277,900.
ACC DEF STATE INCOME TAX	23,353,200.	20,235,600.
DEFERRED CREDITS - OTHER	5,067,901.	1,962,039.
DUE TO AFFILIATES	75,231,553.	81,203,455.
FASB 109 REGULATORY LIABILITY	17,073,625.	19,326,961.
INJURIES AND DAMAGES RESERVE	693,800.	691,270.
OTHER ASSET RETIREMENT OBLIGATIONS	31,832,832.	35,607,059.
Subtotal	391,892,411.	448,304,284.
CLEAN ENERGY ENTERPRISES INC		
DUE TO AFFILIATES	3,177.	4,880.
Subtotal	3,177.	4,880.
ELIMINATIONS SCANA CORPORATIO		
DEFERRED CREDITS - OTHER		436,293,964.
DUE TO AFFILIATES	-442,218,711.	-488,156,930.

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SCANA CORPORATION 57-0784499

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	Beginning	Ending
Line 21 - Other Liabilities (Cont'd)		
Subtotal	-442,218,711.	-51,862,966.
Total Line 21 - Other Liabilities	3,549,178,387.	4,430,749,397.

SCANA CORPORATION 57-0784499

Consolidated Schedules
Sch. M1 and M-2 Summary

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Schedule M-1				
1 Net income per books				
2 Federal Income Tax				
3 Excess Capital Losses				
4 Income Subject to Tax not on Books				
5 Expenses Recorded on Books not Deducted on Return				
a Depreciation				
b Charitable Contributions				
c Travel and Entertainment				
Other				
6 Total Lines 1-5				
7 Income Recorded on Books not Included on Return				
a Tax-exempt Interest				
Other				
8 Deductions on Return not on Books				
a Depreciation				
b Charitable Contributions				
Other				
9 Total Lines 7 and 8				
10 Income (Line 28, Page 1)				
Schedule M-2				
1 Balance at beginning of year	5,594,564,883.	-2,490,250,595.		3,104,314,288.
2 Net Income per Books	1,203,948,384.	-612,397,274.		591,551,110.
3 Other Increases	14,489,404.	-14,489,402.		2.
4 Total Line 1-3	6,813,002,671.	-3,117,137,271.		3,695,865,400.
5 Distributions				
a Cash	697,012,943.	-372,475,000.		324,537,943.
b Stock				
c Property				
6 Other Decreases	-6.			-6.
7 Total lines 5 and 6	697,012,937.	-372,475,000.		324,537,937.
8 Balance at end of year	6,115,989,734.	-2,744,662,271.		3,371,327,463.

SCANA CORPORATION 57-0784499

Consolidated Schedules Sch. M1 and M-2 Summary	SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483
Schedule M-1								
1 Net income per books								
2 Federal Income Tax								
3 Excess Capital Losses								
4 Income Subject to Tax not on Books								
5 Expenses Recorded on Books not Deducted on Return								
a Depreciation								
b Charitable Contributions								
c Travel and Entertainment								
Other								
6 Total Lines 1-5								
7 Income Recorded on Books not Included on Return								
a Tax-exempt Interest								
Other								
8 Deductions on Return not on Books								
a Depreciation								
b Charitable Contributions								
Other								
9 Total Lines 7 and 8								
10 Income (Line 28, Page 1)								
Schedule M-2								
1 Balance at beginning of year	3,111,012,466.		2,265,470,450.		73,707,400.	46,380,846.	-8,580,838.	106,559,263.
2 Net Income per Books	594,087,041.		512,691,484.		13,089,888.	29,813,254.	-15,671.	54,283,691.
3 Other Increases	5,892,892.		3.				8,596,509.	
4 Total Line 1-3	3,710,992,399.		2,778,161,937.		86,797,288.	76,194,100.		160,842,954.
5 Distributions								
a Cash	328,708,943.		296,950,000.		7,575,000.	35,100,000.		28,658,117.
b Stock								
c Property								
6 Other Decreases								-6.
7 Total lines 5 and 6	328,708,943.		296,950,000.		7,575,000.	35,100,000.		28,658,111.
8 Balance at end of year	3,382,283,456.	NONE	2,481,211,937.	NONE	79,222,288.	41,094,100.		132,184,843.

SCANA CORPORATION 57-0784499

Consolidated Schedules Sch. M1 and M-2 Summary	CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
Schedule M-1		
1 Net income per books		
2 Federal Income Tax		
3 Excess Capital Losses		
4 Income Subject to Tax not on Books		
5 Expenses Recorded on Books not Deducted on Return		
a Depreciation		
b Charitable Contributions		
c Travel and Entertainment		
Other		
6 Total Lines 1-5		
7 Income Recorded on Books not Included on Return		
a Tax-exempt Interest		
Other		
8 Deductions on Return not on Books		
a Depreciation		
b Charitable Contributions		
Other		
9 Total Lines 7 and 8		
10 Income (Line 28, Page 1)		
Schedule M-2		
1 Balance at beginning of year	15,296.	
2 Net Income per Books	-1,303.	
3 Other Increases		
4 Total Line 1-3	13,993.	
5 Distributions		
a Cash	20,883.	
b Stock		
c Property		
6 Other Decreases		
7 Total lines 5 and 6	20,883.	
8 Balance at end of year	-6,890.	

SCANA CORPORATION 57-0784499

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Sch. M-2, Line 3 - Other Increases

SCANA CORPORATION	
Dissolution of Westex	5,892,892.
Subtotal	5,892,892.
SOUTH CAROLINA ELECTRIC and GAS COMPANY	
Other Increases	3.
Subtotal	3.
SERVICECARE INC	
Dissolution of ServiceCare	8,596,509.
Subtotal	8,596,509.
ELIMINATIONS SCANA CORPORATIO	
Rounding	-1.
Dissolution of ServiceCare	-8,596,509.
Dissolution of Westex	-5,892,892.
Subtotal	-14,489,402.
Total Sch. M-2, Line 3 - Other Increases	2.

Sch. M-2, Line 6 - Other Decreases

PUBLIC SERVICE COMPANY OF NORTH CAROLINA	
Other Decreases	-6.
Subtotal	-6.
Total Sch. M-2, Line 6 - Other Decreases	-6.

SCANA CORPORATION 57-0784499

Consolidated Schedules 4626-AMT	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1 Taxable income before NOL	-66,447,895.	NONE	3,585,739.	-62,862,156.
Adjustments and Preferences				
2 a Depr. of post 1986 property	-22,088,571.			-22,088,571.
b Amort of pollution control facilities				
c Amort of exploration and dev cost				
d Amort of circulation expenses				
e Adjusted gain or loss	1,703,217.			1,703,217.
f Long-term contracts				
g Merchant marine funds				
h Section 833(b) deduction				
i Tax shelter farm activities				
j Passive activities				
k Loss limitations				
l Depletion				
m Tax exempt interest				
n Intangible drilling costs				
o Other adjustments	NONE	NONE	NONE	NONE
3 Pre-adjustment AMTI	-86,833,249.	NONE	3,585,739.	-83,247,510.
Adjusted current earnings adj				
4 a ACE from line 10 of worksheet	-54,278,167.	NONE	3,585,739.	-50,692,428.
b Line 4a less line 3	32,555,082.	NONE		32,555,082.
c Line 4b multiplied by 75%	24,526,317.	NONE	-110,005.	24,416,312.
d Total increases over reductions				
e ACE adjustment	24,471,314.	NONE	-55,002.	24,416,312.
5 Sum of lines 3 and 4e	-62,361,935.	NONE	3,530,737.	-58,831,198.
6 AMT NOL deduction				
7 Alternative minimum taxable inc.	-62,361,935.	NONE	3,530,737.	-58,831,198.

SCANA CORPORATION 57-0784499

Consolidated Schedules 4626-AMT	SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483
1 Taxable income before NOL	-65,988,499.	10,685,705.	-29,736,612.	9,719,948.	9,555,628.	48,187,155.	-1,192,180.	-47,677,337.
Adjustments and Preferences								
2 a Depr. of post 1986 property			-20,538,989.		-1,370,482.			-179,100.
b Amort of pollution control facilities								
c Amort of exploration and dev cost								
d Amort of circulation expenses								
e Adjusted gain or loss		NONE	1,703,181.		36.			
f Long-term contracts								
g Merchant marine funds								
h Section 833(b) deduction								
i Tax shelter farm activities								
j Passive activities								
k Loss limitations								
l Depletion								
m Tax exempt interest								
n Intangible drilling costs								
o Other adjustments	NONE	NONE	NONE		NONE	NONE		NONE
3 Pre-adjustment AMTI	-65,988,499.	10,685,705.	-48,572,420.	9,719,948.	8,185,182.	48,187,155.	-1,192,180.	-47,856,437.
Adjusted current earnings adj								
4 a ACE from line 10 of worksheet	-38,617,128.	10,685,705.	-43,315,372.	9,719,948.	8,111,845.	48,187,155.	-1,192,180.	-47,856,437.
b Line 4a less line 3	27,371,371.		5,257,048.		-73,337.			
c Line 4b multiplied by 75%	20,528,528.		3,942,786.		55,003.			
d Total increases over reductions								
e ACE adjustment	20,528,528.		3,942,786.					
5 Sum of lines 3 and 4e	-45,459,971.	10,685,705.	-44,629,634.	9,719,948.	8,185,182.	48,187,155.	-1,192,180.	-47,856,437.
6 AMT NOL deduction								
7 Alternative minimum taxable inc.	-45,459,971.	10,685,705.	-44,629,634.	9,719,948.	8,185,182.	48,187,155.	-1,192,180.	-47,856,437.

SCANA CORPORATION 57-0784499

Consolidated Schedules 4626-AMT	CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC. 20-0989017
1 Taxable income before NOL	-1,703.	NONE
Adjustments and Preferences		
2 a Depr. of post 1986 property		
b Amort of pollution control facilities		
c Amort of exploration and dev cost		
d Amort of circulation expenses		
e Adjusted gain or loss		
f Long-term contracts		
g Merchant marine funds		
h Section 833(b) deduction		
i Tax shelter farm activities		
j Passive activities		
k Loss limitations		
l Depletion		
m Tax exempt interest		
n Intangible drilling costs		
o Other adjustments		
3 Pre-adjustment AMTI	-1,703.	NONE
Adjusted current earnings adj		
4 a ACE from line 10 of worksheet	-1,703.	NONE
b Line 4a less line 3		NONE
c Line 4b multiplied by 75%		NONE
d Total increases over reductions		
e ACE adjustment		NONE
5 Sum of lines 3 and 4e	-1,703.	NONE
6 AMT NOL deduction		
7 Alternative minimum taxable inc.	-1,703.	NONE

Form 4626 Detail

Line 2o - Other Adjustments - Contributions Deduction

1.	AMTI (excluding contributions and domestic production activities deduction)	-58,831,198.
2.	Less: NOL carryover	
3.	Plus: Capital Loss carryback	
4.	AMTI without regard to contributions, special deductions, domestic production activities deduction, NOL carrybacks, and capital loss carrybacks	-58,831,198.
5.	Contribution deduction limitation (AMTI x 10%)	NONE
6.	Amount of deductible contributions	3,585,739.
7.	Contribution deduction (Lesser of line 5 or line 6)	NONE

5 Year Contributions carryover

Year ending	Amount Available	Amount Utilized	Carryover to Next Year
12/31/2016	3,585,739.	NONE	3,585,739.
Total	3,585,739.	NONE	3,585,739.

Line 2o - Contributions Adjustment

Regular Contributions	NONE
AMT Contributions	NONE
Contribution adjustment	NONE

SCANA CORPORATION 57-0784499

Form 4626 Detail

Line 2o - Domestic production activities deduction (DPAD) Adjustment

1a. QPAI from oil-related activities	
b. QPAI from all activities	
2. AMTI limitation	-58,831,198.
3. Lesser of line 1b or line 2	
4. 9% of line 3	
5a. Lesser of line 1a or line 2	
b. Reduction for oil-related QPAI (Line 5a x 3%)	
6. Line 4 minus line 5b	
7. Wage limitation	
8. Lesser of line 6 or line 7	
9. DPAD from cooperatives	
10. Expanded affiliated group (EAG) allocation	
11. DPAD for AMT purposes (Sum of lines 8, 9, and 10)	
12. DPAD for regular tax	
13. AMT adjustment for DPAD	

Form 4626 Detail

Line 6 - Non-SRLY AMT NOL Deduction

Year ending	Original NOL	Amount Available	Amount Used	Carryover to Next year
12/31/2016	58,831,198.	58,831,198.		58,831,198.
Total	58,831,198.	58,831,198.		58,831,198.

Consolidated Schedules 4626 - ACE Worksheet	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1 Pre-adjustment AMTI	-86,833,249.	NONE	3,585,739.	-83,247,510.
ACE depreciation adjustment				
2 a AMT depreciation expense	696,995,092.			696,995,092.
b ACE depreciation expense:				
(1) Post-1994 property	244,608,251.			244,608,251.
(2) Post-1990 property				
(3) Pre-1991 MACRS				
(4) Pre-1991 ACRS				
(5) Sec. 168(f)(1)-(4)				
(6) Other property	451,920,654.			451,920,654.
(7) Total ACE depreciation exp.	696,528,905.			696,528,905.
c ACE depreciation adjustment	466,187.			466,187.
Items included in E&P				
3 a Tax exempt interest income				
b Death benefits from life insurance	-268,623.			-268,623.
c Other life insurance distributions				
d Inside buildup of undist. income	4,986,147.			4,986,147.
e Other items				
f Total increase due to E&P items	4,717,524.			4,717,524.
Items not deductible in E&P				
4 a Certain dividends received	212,200.			212,200.
b Public utility dividends	27,159,171.			27,159,171.
c Dividends paid to an ESOP				
d Nonpatronage dividends				
e Other items				
f Total due to disallowed E&P items	27,371,371.			27,371,371.
Other E&P adjustments				
5 a Intangible drilling costs				
b Circulation expenditures				
c Organizational expenditures				
d LIFO inventory adjustments				
e Installment sales				
f Total other E&P adjustments				
6 Loss disallowance on debts pools				
7 Acquisition expenses				
8 Depletion				
9 Basis adj. from sale of property	NONE			NONE
10 Adjusted current earnings	-54,278,167.	NONE	3,585,739.	-50,692,428.

SCANA CORPORATION 57-0784499

Consolidated Schedules
4626 - ACE Worksheet

	SCANA CORPORATION 57-0784499	SCANA SERVICES INC 57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695	SOUTH CAROLINA FUEL CO INC 57-0691209	SC GENERATING COMPANY INC 57-0784498	SCANA ENERGY MARKETING INC 57-0850977	SERVICECARE INC 57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483
1 Pre-adjustment AMTI	-65,988,499.	10,685,705.	-48,572,420.	9,719,948.	8,185,182.	48,187,155.	-1,192,180.	-47,856,437.
ACE depreciation adjustment								
2 a AMT depreciation expense		15,840,260.	452,460,178.	46,060,920.	20,960,829.	955,303.		160,717,602.
b ACE depreciation expense:								
(1) Post-1994 property		15,840,260.		46,060,920.	21,034,166.	955,303.		160,717,602.
(2) Post-1990 property								
(3) Pre-1991 MACRS								
(4) Pre-1991 ACRS								
(5) Sec. 168(f)(1)-(4)								
(6) Other property			451,920,654.					
(7) Total ACE depreciation exp.		15,840,260.	451,920,654.	46,060,920.	21,034,166.	955,303.		160,717,602.
c ACE depreciation adjustment			539,524.		-73,337.			
Items included in E&P								
3 a Tax exempt interest income								
b Death benefits from life insurance			-268,623.					
c Other life insurance distributions								
d Inside buildup of undist. income			4,986,147.					
e Other items								
f Total increase due to E&P items			4,717,524.					
Items not deductible in E&P								
4 a Certain dividends received	212,200.							
b Public utility dividends	27,159,171.							
c Dividends paid to an ESOP								
d Nonpatronage dividends								
e Other items								
f Total due to disallowed E&P items	27,371,371.							
Other E&P adjustments								
5 a Intangible drilling costs								
b Circulation expenditures								
c Organizational expenditures								
d LIFO inventory adjustments								
e Installment sales								
f Total other E&P adjustments								
6 Loss disallowance on debts pools								
7 Acquisition expenses								
8 Depletion								
9 Basis adj. from sale of property		NONE						
10 Adjusted current earnings	-38,617,128.	10,685,705.	-43,315,372.	9,719,948.	8,111,845.	48,187,155.	-1,192,180.	-47,856,437.

Consolidated Schedules 4626 - ACE Worksheet	CLEAN ENERGY ENTERPRISES INC 56-1078443	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
1 Pre-adjustment AMTI	-1,703.	NONE
ACE depreciation adjustment		
2 a AMT depreciation expense		
b ACE depreciation expense:		
(1) Post-1994 property		
(2) Post-1990 property		
(3) Pre-1991 MACRS		
(4) Pre-1991 ACRS		
(5) Sec. 168(f)(1)-(4)		
(6) Other property		
(7) Total ACE depreciation exp.		
c ACE depreciation adjustment		
Items included in E&P		
3 a Tax exempt interest income		
b Death benefits from life insurance		
c Other life insurance distributions		
d Inside buildup of undist. income		
e Other items		
f Total increase due to E&P items		
Items not deductible in E&P		
4 a Certain dividends received		
b Public utility dividends		
c Dividends paid to an ESOP		
d Nonpatronage dividends		
e Other items		
f Total due to disallowed E&P items		
Other E&P adjustments		
5 a Intangible drilling costs		
b Circulation expenditures		
c Organizational expenditures		
d LIFO inventory adjustments		
e Installment sales		
f Total other E&P adjustments		
6 Loss disallowance on debts pools		
7 Acquisition expenses		
8 Depletion		
9 Basis adj. from sale of property		
10 Adjusted current earnings	-1,703.	NONE

SCANA CORPORATION

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Consolidated Schedules				
Schedule D				
Short-Term Capital Gains and Losses				
1 a Short-term not on Form 8949				
1 b Form 8949, Part I, Box A				
2 Form 8949, Part I, Box B				
3 Form 8949, Part I, Box C	-4,979.			-4,979.
4 Gain from installment sales				
5 Gain or loss from Form 8824				
6 Unused capital loss carryover				
7 Net short-term gains and losses	-4,979.			-4,979.
Long-Term Capital Gains and Losses				
8 a Long-term not on Form 8949				
8 b Form 8949, Part II, Box D				
9 Form 8949, Part II, Box E				
10 Form 8949, Part II, Box F	77,345.			77,345.
11 Form 4797 Part I gain	1,646.		-1,646.	
12 Gain from installment sales				
13 Gain or loss from Form 8824				
14 Capital gain distributions	158,428.			158,428.
15 Net long-term gains and losses	237,419.		-1,646.	235,773.
Summary				
16 Short-term gain over long-term loss				
17. Long-term gain over short-term loss	232,440.		-1,646.	230,794.
18 Net capital gain	232,440.		-1,646.	230,794.

SCANA CORPORATION

Consolidated Schedules
Schedule D

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
	57-0784499	57-1092169	57-0248695	57-0691209	57-0784490	57-0850977	57-1007394	56-2128483
Short-Term Capital Gains and Losses								
1 a Short-term not on Form 8949								
1 b Form 8949, Part I, Box A								
2 Form 8949, Part I, Box B								
3 Form 8949, Part I, Box C	-4,979.							
4 Gain from installment sales								
5 Gain or loss from Form 8824								
6 Unused capital loss carryover								
7 Net short-term gains and losses	-4,979.							
Long-Term Capital Gains and Losses								
8 a Long-term not on Form 8949								
8 b Form 8949, Part II, Box D								
9 Form 8949, Part II, Box E								
10 Form 8949, Part II, Box F	77,345.		NONE					
11 Form 4797 Part I gain		NONE				1,646.		
12 Gain from installment sales								
13 Gain or loss from Form 8824								
14 Capital gain distributions	158,428.							
15 Net long-term gains and losses	235,773.	NONE	NONE			1,646.		
Summary								
16 Short-term gain over long-term loss								
17 Long-term gain over short-term loss	230,794.	NONE	NONE			1,646.		
18 Net capital gain	230,794.	NONE	NONE			1,646.		

SCANA CORPORATION

Consolidated Schedules
Schedule D

	CLEAN ENERGY ENTERPRISES INC	SCANA CORPORATE SECURITY SERVICES INC
	56-1078443	20-0989017
Short-Term Capital Gains and Losses		
1 a Short-term not on Form 8949		
1 b Form 8949, Part I, Box A		
2 Form 8949, Part I, Box B		
3 Form 8949, Part I, Box C		
4 Gain from installment sales		
5 Gain or loss from Form 8824		
6 Unused capital loss carryover		
7 Net short-term gains and losses		
Long-Term Capital Gains and Losses		
8 a Long-term not on Form 8949		
8 b Form 8949, Part II, Box D		
9 Form 8949, Part II, Box E		
10 Form 8949, Part II, Box F		
11 Form 4797 Part I gain		
12 Gain from installment sales		
13 Gain or loss from Form 8824		
14 Capital gain distributions		
15 Net long-term gains and losses		
Summary		
16 Short-term gain over long-term loss		
17 Long-term gain over short-term loss		
18 Net capital gain		

Schedule D Detail - Capital Gain Distributions

SCANA CORPORATION

Line 14 - Capital Gains Distributions

Name of Payer	Amount
SCANA EXECUTIVE BENEFIT TRUST	158,428.
Total Capital Gains Distributions	158,428.

SCANA CORPORATION 57-0784499

Consolidated Schedules Schedule M-3, Part II	Combined Per Inc Stmt	Temporary	Permanent	Per Tax Return	ELIMINATIONS SCANA CORPORATIO Per Inc Stmt	Temporary	Permanent	Per Tax Return
1 Income (loss) from equity method foreign corp.								
2 Gross foreign dividends not previously taxed		34,349.		34,349.				
3 Subpart F, QEF, and similar income inclusions								
4 Section 78 gross-up								
5 Gross foreign distrib. previously taxed								
6 Income (loss) from equity method U.S. corp.	612,397,274.		-612,397,274.		-612,397,274.		612,397,274.	
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.				
8 Minority interest for includible corp.								
9 Income (loss) from U.S. partnerships								
10 Income (loss) from foreign partnerships								
11 Income (loss) from other pass-through entities	-3,486,238.	-1,380,838.		-4,867,076.				
12 Items relating to reportable transactions								
13 Interest income	49,665,106.	200,985,885.		250,650,991.	-9,434,559.			-9,434,559.
14 Total accrual to cash adjustment								
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.				
16 Mark-to-market income (loss)								
17 Cost of goods sold	2,545,357,167.	72,440,739.		2,472,916,428.	-376,357,089.			-376,357,089.
18 Sales versus lease								
19 Section 481(a) adjustments								
20 Unearned/deferred revenue								
21 Income recognition from long-term contracts								
22 Original issue discount/imputed interest								
23a Income statement gain/loss on sale, exchange, or abandonment	566,889.	-566,889.						
23b Gross cap. gains from Sch. D, excluding amount from pass-through entities		235,773.		235,773.				
23c Gross cap. losses from Sch. D, exc. pass-through ent., abandonment, worthless stock		-4,979.		-4,979.				
23d Net gain/loss reported on Form 4797		-51,771,917.		-51,771,917.				
23e Abandonment losses								
23f Worthless stock losses								
23g Other gain/loss on disposition of assets other than inventory								
24 Capital loss limitation and carryforward used								
25 Other income (loss) items with differences	4,348,156,767.	24,580,638.	222,694.	4,372,960,099.				
26 Total income (loss) items	2,440,572,347.	244,604,783.	-612,174,580.	2,073,002,550.	-245,474,744.		612,397,274.	366,922,530.
27 Total expense/deduction items	-1,667,175,742.	-1,113,798,663.	211,184,381.	-2,569,790,024.	54,932,991.			54,932,991.
28 Other items with no differences	430,551,779.			430,551,779.	-421,855,521.			-421,855,521.
29a 1120 subgroup reconciliation totals	1,203,948,384.	-869,193,880.	-400,990,199.	-66,235,695.	-612,397,274.		612,397,274.	
29b PC insurance subgroup reconciliation totals								
29c Life insurance subgroup reconciliation totals								
30 Reconciliation totals	1,203,948,384.	-869,193,880.	-400,990,199.	-66,235,695.	-612,397,274.		612,397,274.	

SCANA CORPORATION 57-0784499

Consolidated Schedules Schedule M-3, Part II	Adjustments Per Inc Stmt	Temporary	Permanent	Per Tax Return	SCANA CORPORATION Per Inc Stmt	Temporary	Permanent	Per Tax Return
1 Income (loss) from equity method foreign corp.								
2 Gross foreign dividends not previously taxed						34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions								
4 Section 78 gross-up								
5 Gross foreign distrib. previously taxed								
6 Income (loss) from equity method U.S. corp.								
7 U.S. dividends not eliminated in tax consolidation						303,143.		303,143.
8 Minority interest for includible corp.								
9 Income (loss) from U.S. partnerships								
10 Income (loss) from foreign partnerships								
11 Income (loss) from other pass-through entities					-3,486,238.	-1,380,838.		-4,867,076.
12 Items relating to reportable transactions								
13 Interest income					40,230,547.	200,985,885		241,216,432.
14 Total accrual to cash adjustment								
15 Hedging transactions					-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)								
17 Cost of goods sold					2,169,000,078.	72,440,739.		2,096,559,339.
18 Sales versus lease								
19 Section 481(a) adjustments								
20 Unearned/deferred revenue								
21 Income recognition from long-term contracts								
22 Original issue discount/imputed interest								
23a Income statement gain/loss on sale, exchange, or abandonment					566,889.	-566,889.		
23b Gross cap. gains from Sch. D, excluding amount from pass-through entities						235,773.		235,773.
23c Gross cap. losses from Sch. D, exc. pass-through ent., abandonment, worthless stock						-4,979.		-4,979.
23d Net gain/loss reported on Form 4797						-51,771,917.		-51,771,917.
23e Abandonment losses								
23f Worthless stock losses								
23g Other gain/loss on disposition of assets other than inventory								
24 Capital loss limitation and carryforward used								
25 Other income (loss) items with differences					4,348,156,767.	24,580,638.	222,694.	4,372,960,099.
26 Total income (loss) items					2,195,097,603.	244,604,783.	222,694.	2,439,925,080.
27 Total expense/deduction items			3,585,739.	3,585,739.	-1,612,242,751.	-1,113,798,663.	214,770,120.	-2,511,271,294.
28 Other items with no differences					8,696,258.			8,696,258.
29a 1120 subgroup reconciliation totals			3,585,739.	3,585,739.	591,551,110.	-869,193,880.	214,992,814.	-62,649,956.
29b PC insurance subgroup reconciliation totals								
29c Life insurance subgroup reconciliation totals								
30 Reconciliation totals			3,585,739.	3,585,739.	591,551,110.	-869,193,880.	214,992,814.	-62,649,956.

SCANA CORPORATION 57-0784499

Schedule M-3, Part II Detail

Line 25 - Other income (loss) items with differences

Description	Income (Loss) Per Income Stmt	Temporary Difference	Permanent Difference	Income (Loss) Per Tax Return
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
GROSS SALES	2,974,321,805.	24,317,336.	60,389.	2,998,699,530.
Subtotal	2,974,321,805.	24,317,336.	60,389.	2,998,699,530.
SCANA ENERGY MARKETING INC				
GROSS SALES	938,014,128.	263,302.		938,277,430.
Subtotal	938,014,128.	263,302.		938,277,430.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
GROSS SALES	435,820,834.		162,305.	435,983,139.
Subtotal	435,820,834.		162,305.	435,983,139.
Total	4,348,156,767.	24,580,638.	222,694.	4,372,960,099.

Schedule M-3, Part II Detail

Line 28 - Other items with no differences

SCANA CORPORATION

SELLING EXPENSES	154,162.
OFFICE SUPPLIES AND EXPENSES	-1,926.
OUTSIDE SERVICES	-2,030.
TAXES AND LICENSES	-287,115.
Subtotal	-136,909.

SCANA SERVICES INC

GAIN ON LAND SALES	269,581.
GROSS SALES	413,279,684.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	452,837.
RENTAL INCOME	735,204.
SELLING EXPENSES	19,408.
ADVERTISING	-814,120.
INSURANCE	-139,629.
MERCHANDISING EXPENSES	-1,301,752.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-21,072,152.
OFFICE SUPPLIES AND EXPENSES	-35,981,453.
OUTSIDE SERVICES	-27,195,321.
RENT EXPENSE	-9,357,222.
TAXES AND LICENSES	-16,528,705.
Subtotal	302,366,360.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

GAIN ON LAND SALES	621,436.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	14,445,489.
RENTAL INCOME	20,964,105.
ADVERTISING	-371,874.
INSURANCE	-7,158,823.
MERCHANDISING EXPENSES	-1,031,448.
OFFICE SUPPLIES AND EXPENSES	-20,537,993.
RENT EXPENSE	-6,587,833.
TAXES AND LICENSES	-230,655,590.
Subtotal	-230,312,531.

Continued on next page

SCANA CORPORATION 57-0784499

Schedule M-3, Part II Detail

Line 28 - Other items with no differences (Cont'd)

SOUTH CAROLINA FUEL CO INC

GROSS SALES	237,225,342.
OFFICE SUPPLIES AND EXPENSES	-65.
OUTSIDE SERVICES	-236,512.
SALARIES AND WAGES	-3,529.
TAXES AND LICENSES	-2,978.
Subtotal	236,982,258.

SC GENERATING COMPANY INC

GROSS SALES	193,888,768.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-585,541.
RENTAL INCOME	10,903.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-713,109.
OFFICE SUPPLIES AND EXPENSES	-538,492.
OUTSIDE SERVICES	-520,912.
RENT EXPENSE	-78,729.
SALARIES AND WAGES	-1,541,100.
TAXES AND LICENSES	-7,397,963.
Subtotal	182,523,825.

SCANA ENERGY MARKETING INC

MISCELLANEOUS INCOME WITHOUT DIFFERENCES	10,217.
ADVERTISING	-11,082,729.
INSURANCE	-264,821.
OFFICE SUPPLIES AND EXPENSES	-7,529,342.
OUTSIDE SERVICES	-1,912,193.
RENT EXPENSE	-1,974,447.
REPAIRS AND MAINTENANCE	-574,178.
TAXES AND LICENSES	-2,014,177.
Subtotal	-25,341,670.

SERVICECARE INC

MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-24,640.

Continued on next page

Schedule M-3, Part II Detail

Line 28 - Other items with no differences (Cont'd)

OFFICE SUPPLIES AND EXPENSES	-4,031.
REPAIRS AND MAINTENANCE	-356.
SALARIES AND WAGES	-2,541.
TAXES AND LICENSES	-359.
Subtotal	-31,927.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

GAIN ON LAND SALES	-56,193.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	12,035,707.
RENTAL INCOME	775,752.
ADVERTISING	-1,030,810.
INSURANCE	-592,872.
MERCHANDISING EXPENSES	-2,130,960.
OFFICE SUPPLIES AND EXPENSES	-7,790,943.
OUTSIDE SERVICES	-2,462,139.
RENT EXPENSE	-1,817,714.
REPAIRS AND MAINTENANCE	-17,874,475.
TAXES AND LICENSES	-14,551,277.
Subtotal	-35,495,924.

CLEAN ENERGY ENTERPRISES INC

OFFICE SUPPLIES AND EXPENSES	-703.
TAXES AND LICENSES	-1,000.
Subtotal	-1,703.

ELIMINATIONS SCANA CORPORATIO

GAIN ON LAND SALES	-269,581.
GROSS SALES	-719,988,460.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	-452,837.
RENTAL INCOME	-6,676,572.
SELLING EXPENSES	-19,408.
ADVERTISING	814,120.
INSURANCE	139,629.
MERCHANDISING EXPENSES	1,478,536.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	35,176,019.

Continued on next page

SCANA CORPORATION 57-0784499

Schedule M-3, Part II Detail

Line 28 - Other items with no differences (Cont'd)

OFFICE SUPPLIES AND EXPENSES	37,231,910.
OUTSIDE SERVICES	27,195,321.
RENT EXPENSE	15,121,806.
REPAIRS AND MAINTENANCE	55,589,061.
SALARIES AND WAGES	116,276,230.
TAXES AND LICENSES	16,528,705.
Subtotal	-421,855,521.
Total	8,696,258.

SCANA CORPORATION 57-0784499

Consolidated Schedules Schedule M-3, Part III	Combined Per Inc Stmt	Combined Temporary	Combined Permanent	Combined Per Tax Return	ELIMINATIONS SCANA CORPORATIO Per Inc Stmt	ELIMINATIONS SCANA CORPORATIO Temporary	ELIMINATIONS SCANA CORPORATIO Permanent	ELIMINATIONS SCANA CORPORATIO Per Tax Return
1 U.S. current income tax exp.	33,246,005.		-33,246,005.					
2 U.S. deferred income tax exp.	201,820,874.		-201,820,874.					
3 State and local current income tax exp.	12,805,324.	-11,240,307.		1,565,017.				
4 State and local deferred income tax exp.	21,269,254.	-21,269,254.						
5 Foreign current income tax exp.								
6 Foreign deferred income tax exp.								
7 Foreign withholding taxes								
8 Interest expense	361,995,641.	42,908,253.		404,903,894.	-19,726,271.			-19,726,271.
9 Stock option expense								
10 Other equity-based compensation								
11 Meals and entertainment	2,833,057.		-1,501,983.	1,331,074.				
12 Fines and penalties	-346,594.		346,594.					
13 Judgments, damages, awards, and similar costs	14,456,497.	-2,378,759.		12,077,738.	-5,113,014.			-5,113,014.
14 Parachute payments								
15 Compensation with sect. 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.				
16 Pension and profit-sharing	24,864,595.	-23,804,767.		1,059,828.	-364,871.			-364,871.
17 Other post-retirement benefits	90,740,610.	-4,266,874.		86,473,736.	-29,670,928.			-29,670,928.
18 Deferred compensation	4,528,916.	-4,528,916.						
19 Charitable contribution - cash/tangibles	3,083,562.	497,595.	4,582.	3,585,739.				
20 Charitable contribution - intangible								
21 Charitable contribution limitation/carryforward								
22 Domestic production activities deduction								
23 Current year acquisition or reorg. investment banking fees								
24 Current year acquisition or reorg. legal and accounting fees								
25 Current year acquisition/reorg. other costs								
26 Amortization/impairment of goodwill								
27 Amortization of acquisition and reorg.								
28 Other amort. or impairment write-offs	4,391,015.	7,212,662.		11,603,677.				
29 Reserved								
30 Depletion								
31 Depreciation	352,117,080.	322,789,444.		674,906,524.				
32 Bad debt expense	10,989,039.	-583,897.		10,405,142.	-57,907.			-57,907.
33 Corporate owned life insurance premiums	-624,899.		624,899.					
34 Purchase versus lease								
35 Research and development costs		722,622,385.		722,622,385.				
36 Section 118 exclusion								
37 Other expense/ded. items with differ.	511,355,651.	85,841,098.	26,913,688.	624,110,437.				
38 Total expense/deduction items	1,667,175,742.	1,113,798,663.	-211,184,381.	2,569,790,024.	-54,932,991.			-54,932,991.

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SCANA CORPORATION 57-0784499

	Consolidated Schedules Schedule M-3, Part III	Adjustments Per Inc Stmt	Adjustments Temporary	Adjustments Permanent	Adjustments Per Tax Return	SCANA CORPORATION Per Inc Stmt	SCANA CORPORATION Temporary	SCANA CORPORATION Permanent	SCANA CORPORATION Per Tax Return
1	U.S. current income tax exp.					33,246,005.		-33,246,005.	
2	U.S. deferred income tax exp.					201,820,874.		-201,820,874.	
3	State and local current income tax exp.					12,805,324.	-11,240,307.		1,565,017.
4	State and local deferred income tax exp.					21,269,254.	-21,269,254.		
5	Foreign current income tax exp.								
6	Foreign deferred income tax exp.								
7	Foreign withholding taxes								
8	Interest expense					342,269,370.	42,908,253.		385,177,623.
9	Stock option expense								
10	Other equity-based compensation								
11	Meals and entertainment					2,833,057.		-1,501,983.	1,331,074.
12	Fines and penalties					-346,594.		346,594.	
13	Judgments, damages, awards, and similar costs					9,343,483.	-2,378,759.		6,964,724.
14	Parachute payments								
15	Compensation with secl. 162(m) limitation					17,650,115.		-2,505,282.	15,144,833.
16	Pension and profit-sharing					24,499,724.	-23,804,767.		694,957.
17	Other post-retirement benefits					61,069,682.	-4,266,874.		56,802,808.
18	Deferred compensation					4,528,916.	-4,528,916.		
19	Charitable contribution - cash/tangibles					3,083,562.	497,595.	4,582.	3,585,739.
20	Charitable contribution - intangible								
21	Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.			-3,585,739.	-3,585,739.
22	Domestic production activities deduction								
23	Current year acquisition or reorg. investment banking fees								
24	Current year acquisition or reorg. legal and accounting fees								
25	Current year acquisition/reorg. other costs								
26	Amortization/impairment of goodwill								
27	Amortization of acquisition and reorg.								
28	Other amort. or impairment write-offs					4,391,015.	7,212,662.		11,603,677.
29	Reserved								
30	Depletion								
31	Depreciation					352,117,080.	322,789,444.		674,906,524.
32	Bad debt expense					10,931,132.	-583,897.		10,347,235.
33	Corporate owned life insurance premiums					-624,899.		624,899.	
34	Purchase versus lease								
35	Research and development costs						722,622,385.		722,622,385.
36	Section 118 exclusion								
37	Other expense/ded. items with differ.					511,355,651.	85,841,098.	26,913,688.	624,110,437.
38	Total expense/deduction items			-3,585,739.	-3,585,739.	1,612,242,751.	1,113,798,663.	-214,770,120.	2,511,271,294.

Schedule M-3, Part III Detail

Line 18 - Deferred compensation

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SCANA CORPORATION				
Deferred compensation	4,528,916.	-4,528,916.		
Subtotal	4,528,916.	-4,528,916.		
Total	4,528,916.	-4,528,916.		

Line 35 - Research and development costs

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SCANA SERVICES INC				
RESEARCH AND DEVELOPMENT		882,125.		882,125.
Subtotal		882,125.		882,125.
SOUTH CAROLINA ELECTRIC and GAS COMPANY				

Continued on next page

Schedule M-3, Part III Detail

Line 35 - Research and development costs (Cont'd)

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
RESEARCH AND DEVELOPMENT		721,608,322.		721,608,322.
Subtotal		721,608,322.		721,608,322.
SCANA ENERGY MARKETING INC				
RESEARCH AND DEVELOPMENT		131,938.		131,938.
Subtotal		131,938.		131,938.
Total		722,622,385.		722,622,385.

Line 37 - Other expense/deduction items with differences

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SCANA CORPORATION				
DIRECTORS ENDOWMENT	6,411.	-6,411.		
MISCELLANEOUS DEDUCTIONS	2,460,031.	-2,460,031.		

Continued on next page

SCANA CORPORATION 57-0784499

Schedule M-3, Part III Detail

Line 37 - Other expense/deduction items with differences (Cont'd)

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	-4,191,550.	1,004,977.		-3,186,573.
SALARIES AND WAGES	1,746.	369,640.		371,386.
ESOP DIVIDENDS			27,159,171.	27,159,171.
Subtotal	-1,723,362.	-1,091,825.	27,159,171.	24,343,984.
SCANA SERVICES INC				
REPAIRS AND MAINTENANCE	52,169,644.	-435,305.		51,734,339.
SALARIES AND WAGES	116,276,230.	-13,288,728.		102,987,502.
Subtotal	168,445,874.	-13,724,033.		154,721,841.
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
DIRECTORS ENDOWMENT	206,858.	-206,858.		
MISCELLANEOUS DEDUCTIONS	12,049,946.	37,995,832.		50,045,778.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	46,217,761.	5,441,757.		51,659,518.
OUTSIDE SERVICES	14,724,420.	1,682,475.		16,406,895.
REPAIRS AND MAINTENANCE	159,686,858.	55,714,794.		215,401,652.
SALARIES AND WAGES	56,897,111.	-1,489,976.	-218,753.	55,188,382.
CONTRIBUTION IN AID OF CONSTRUCTION		-17,084,713.		-17,084,713.
481A ADJUSTMENT		-4,228,547.		-4,228,547.
Subtotal	289,782,954.	77,824,764.	-218,753.	367,388,965.

Continued on next page

Schedule M-3, Part III Detail

Line 37 - Other expense/deduction items with differences (Cont'd)

Description	Expense Per Income Stmt	Temporary Difference	Permanent Difference	Deduction Per Tax Return
SC GENERATING COMPANY INC				
DIRECTORS ENDOWMENT	9,644.	-9,644.		
INSURANCE	647,872.	6,531.		654,403.
REPAIRS AND MAINTENANCE	11,416,935.	7,308,716.		18,725,651.
Subtotal	12,074,451.	7,305,603.		19,380,054.
SCANA ENERGY MARKETING INC				
DIRECTORS ENDOWMENT	26,306.	-26,306.		
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	2,198,526.	-4,985.		2,193,541.
SALARIES AND WAGES	16,604,698.	-469,467.		16,135,231.
Subtotal	18,829,530.	-500,758.		18,328,772.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
DIRECTORS ENDOWMENT	32,041.	-32,041.		
MISCELLANEOUS DEDUCTIONS		1,803,559.		1,803,559.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERE	3,211,821.	14,384,232.		17,596,053.
SALARIES AND WAGES	20,702,342.	-128,403.	-26,730.	20,547,209.
Subtotal	23,946,204.	16,027,347.	-26,730.	39,946,821.
Total	511,355,651.	85,841,098.	26,913,688.	624,110,437.

SCANA CORPORATION 57-0784499

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Consolidated Schedules				
Cost of Goods Sold				
1 Inventory - beginning	311,778,910.			311,778,910.
2 Purchases	842,119,024.	-111,453,041.		730,665,983.
3 Cost of Labor	-429,280.			-429,280.
4 Addit. 263A Costs				
5 Other Costs	1,631,550,024.	-264,904,048.		1,366,645,976.
6 Total	2,785,018,678.	-376,357,089.		2,408,661,589.
7 Inventory - Ending	290,480,845.			290,480,845.
8 Cost of Goods Sold	2,494,537,833.	-376,357,089.		2,118,180,744.

SCANA CORPORATION 57-0784499

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
Consolidated Schedules	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	57-0850977	57-1007394	56-2128483
Cost of Goods Sold								
1 Inventory - beginning		287,791.	171,415,921.	38,266,358.	24,000,296.	25,425,070.		52,383,474.
2 Purchases		62,203.	5,268,408.	-10,885,113.	1,835,212.	688,744,268.		157,094,046.
3 Cost of Labor			-420,319.					-8,961.
4 Addtl. 263A Costs								
5 Other Costs		74,318,188.	1,084,947,563.	179,355,049.	113,725,200.	144,322,159.		34,881,865.
6 Total		74,668,182.	1,261,211,573.	206,736,294.	139,560,708.	858,491,497.		244,350,424.
7 Inventory - Ending		349,994.	172,900,770.	27,381,245.	25,835,508.	24,739,139.		39,274,189.
8 Cost of Goods Sold		74,318,188.	1,088,310,803.	179,355,049.	113,725,200.	833,752,358.		205,076,235.

SCANA CORPORATION 57-0784499

	CLEAN ENERGY ENTERPRISES INC	SCANA CORPORATE SECURITY SERVICES INC
Consolidated Schedules	56-1078443	20-0989017
Cost of Goods Sold		
1 Inventory - beginning		
2 Purchases		
3 Cost of Labor		
4 Addtl. 263A Costs		
5 Other Costs		
6 Total		
7 Inventory - Ending		
8 Cost of Goods Sold		

SCANA CORPORATION 57-0784499

Form 1125-A Detail

Line 5 - Other Costs (Cost of Goods Sold)

SCANA SERVICES INC	
ELECTRIC - DISTRIBUTION	1,851,944.
ELECTRIC - GENERAL	354,777.
ELECTRIC - PRODUCTION	5,945,786.
ELECTRIC - SALES PROMOTION	1,576,312.
ELECTRIC - TRANSMISSION	452,432.
GAS - CUSTOMER ACCOUNTS	60,665,935.
GAS - DISTRIBUTION	2,133,002.
GAS - PRODUCTION	840,817.
GAS - TRANSMISSION	211,713.
OTHER COSTS	285,470.
Subtotal	74,318,188.
SOUTH CAROLINA ELECTRIC and GAS COMPANY	
ELECTRIC - DISTRIBUTION	15,271,035.
ELECTRIC - GENERAL	-2,620,344.
ELECTRIC - PRODUCTION	826,249,729.
ELECTRIC - SALES PROMOTION	6,663,922.
ELECTRIC - TRANSMISSION	9,288,573.
GAS - CUSTOMER ACCOUNTS	53,410,559.
GAS - DISTRIBUTION	9,133,565.
GAS - PRODUCTION	184,185,087.
GAS - TRANSMISSION	235.
OTHER COSTS	-16,634,798.
Subtotal	1,084,947,563.
SOUTH CAROLINA FUEL CO INC	
ELECTRIC - PRODUCTION	179,355,049.
Subtotal	179,355,049.
SC GENERATING COMPANY INC	
ELECTRIC - GENERAL	4,966.
ELECTRIC - PRODUCTION	113,720,234.
Subtotal	113,725,200.

Continued on next page Statement 66

SCANA CORPORATION 57-0784499

Form 1125-A Detail

Line 5 - Other Costs (Cost of Goods Sold) (Cont'd)

SCANA ENERGY MARKETING INC

ELECTRIC - GENERAL	128,082.
ELECTRIC - SALES PROMOTION	144,516.
GAS - CUSTOMER ACCOUNTS	13,131,414.
HEDGING GAIN/LOSS	21,621,405.
OTHER COSTS	197,243.
OTHER STORAGE EXPENSES	31,549,718.
TRANSPORTATION EXPENSES	77,549,781.
Subtotal	144,322,159.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

ELECTRIC - GENERAL	729,521.
ELECTRIC - SALES PROMOTION	2,434,991.
GAS - CUSTOMER ACCOUNTS	12,489,629.
GAS - DISTRIBUTION	14,040,541.
GAS - PRODUCTION	1,350,844.
GAS - TRANSMISSION	3,574,987.
OTHER COSTS	261,352.
Subtotal	34,881,865.

ELIMINATIONS SCANA CORPORATIO

ELECTRIC - DISTRIBUTION	-1,851,944.
ELECTRIC - GENERAL	-354,777.
ELECTRIC - PRODUCTION	-196,415,137.
ELECTRIC - SALES PROMOTION	-1,576,312.
ELECTRIC - TRANSMISSION	-452,432.
GAS - CUSTOMER ACCOUNTS	-60,665,935.
GAS - DISTRIBUTION	-2,133,002.
GAS - PRODUCTION	-840,817.
GAS - TRANSMISSION	-328,222.
OTHER COSTS	-285,470.
Subtotal	-264,904,048.
Total Line 5 - Other Costs (Cost of Goods Sold)	1,366,645,976.

SCANA CORPORATION 57-0784499

Form 1125-E Detail

Name	Soc Sec #	% Bus	% Com	% Pref	Amount
Compensation of Officers					
SOUTH CAROLINA ELECTRIC and GAS COMPANY					
G T DEVLIN		100.000			507,901.
K R JACKSON		100.000			440,676.
R M SENN		100.000			521,767.
J B ARCHIE		100.000			663,712.
W J TURNER III		100.000			343,678.
T D GATLIN		100.000			466,822.
K B MARSH		100.000			1,000,000.
D F KASSIS		100.000			320,047.
S O SHULER JR		100.000			274,630.
D R HARRIS		100.000			678,557.
M K PHALEN		100.000			642,450.
S L DOZIER		100.000			311,757.
W K KISSAM		100.000			713,735.
M R CANNON		100.000			417,860.
S D BURCH		100.000			511,044.
J E ADDISON		100.000			1,210,131.
R G EDWARDS		100.000			363,186.
F R HOWARD		100.000			337,440.
C B LOVE		100.000			320,282.
J P HUDSON		100.000			401,275.
S A BYRNE		100.000			1,000,000.
P N XANTHAKOS		100.000			248,261.
J M LANDRETH		100.000			397,926.
J E SWAN IV		100.000			494,765.
G S CHAMPION		100.000			372,357.
W A MCAULAY		100.000			246,381.
G B RATCHFORD		100.000			347,127.
S K BOWEN		100.000			172,144.
M S RANDALL		100.000			274,451.
H E BARTON JR		100.000			253,884.
R T LINDSAY		100.000			199,954.
R A JONES		100.000			278,471.
A C HIGGINS		100.000			412,162.
Total - Compensation of Officers					15,144,833.

Compensation of officers deducted on tax return 15,144,833.

SCANA CORPORATION

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Consolidated Schedules - Form 4562				
Consolidated 4562 Summary				
Part I - Section 179 Expense				
2 Sec 179 property placed in Service in current year				
6 Nonlisted property				
7 Listed property				
8 Total elected cost				
9 Tentative deduction				
10 Carryover from 2015				
12 Sec 179 expense deduction				
13 Carryover to 2017				
Part II - Other Depreciation				
14 Special depreciation allowance	309,573,587.			309,573,587.
15 Property subject to 168(f)(1)				
16 ACRS and other depreciation	2,616,055.			2,616,055.
Part III - MACRS				
17 MACRS deduction - prior years	347,024,206.			347,024,206.
19 General Depreciation System				
a. 3-year property				
b. 5-year property	1,964,443.			1,964,443.
c. 7-year property	1,879,486.			1,879,486.
d. 10-year property				
e. 15-year property	6,315,785.			6,315,785.
f. 20-year property	5,527,192.			5,527,192.
g. 25-year property				
h. 27.5-year residential real				
i. 39-year nonresidential real	5,770.			5,770.
20 Alternative Depreciation System				
a. Class life				
b. 12-year				
c. 40-year				
Part IV - Summary				
21 Listed Property				
22 Total depreciation	674,906,524.			674,906,524.
42 Amortization - current year	2,067,441.			2,067,441.
43 Amortization - prior year	9,536,236.			9,536,236.
44 Total Amortization	11,603,677.			11,603,677.

SCANA CORPORATION

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
Consolidated Schedules - Form 4562								
Consolidated 4562 Summary	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	57-0850977	57-1007394	56-2128483
Part I - Section 179 Expense								
2 Sec 179 property placed in Service in current year								
6 Nonlisted property								
7 Listed property								
8 Total elected cost								
9 Tentative deduction								
10 Carryover from 2015								
12 Sec 179 expense deduction								
13 Carryover to 2017								
Part II - Other Depreciation								
14 Special depreciation allowance		6,631,122.	196,749,764.		918,907.	775,871.		104,497,923.
15 Property subject to 168(f)(1)								
16 ACRS and other depreciation			2,285,905.					330,150.
Part III - MACRS								
17 MACRS deduction - prior years		8,439,995.	223,119,828.	46,060,920.	18,637,528.	179,432.		50,586,503.
19 General Depreciation System								
a. 3-year property								
b. 5-year property		693,355.	613,002.					658,086.
c. 7-year property		75,557.	1,756,409.					47,520.
d. 10-year property								
e. 15-year property			3,731,461.					2,584,321.
f. 20-year property			3,662,527.		33,912.			1,830,753.
g. 25-year property								
h. 27.5-year residential real								
i. 39-year nonresidential real		231.	2,296.					3,243.
20 Alternative Depreciation System								
a. Class life								
b. 12-year								
c. 40-year								
Part IV - Summary								
21 Listed Property								
22 Total depreciation		15,840,260.	431,921,192.	46,060,920.	19,590,347.	955,303.		160,538,502.
42 Amortization - current year		493,942.	1,344,971.		3,743.	169,268.		55,517.
43 Amortization - prior year		1,645,176.	6,771,800.		98,050.	929,379.		91,831.
44 Total Amortization		2,139,118.	8,116,771.		101,793.	1,098,647.		147,348.

SCANA CORPORATION

	CLEAN ENERGY ENTERPRISES INC	SCANA CORPORATE SECURITY SERVICES INC
Consolidated Schedules - Form 4562		
Consolidated 4562 Summary	56-1078443	20-0989017
Part I - Section 179 Expense		
2 Sec 179 property placed in Service in current year		
6 Nonlisted property		
7 Listed property		
8 Total elected cost		
9 Tentative deduction		
10 Carryover from 2015		
12 Sec 179 expense deduction		
13 Carryover to 2017		
Part II - Other Depreciation		
14 Special depreciation allowance		
15 Property subject to 168(f)(1)		
16 ACRS and other depreciation		
Part III - MACRS		
17 MACRS deduction - prior years		
19 General Depreciation System		
a. 3-year property		
b. 5-year property		
c. 7-year property		
d. 10-year property		
e. 15-year property		
f. 20-year property		
g. 25-year property		
h. 27.5-year residential real		
i. 39-year nonresidential real		
20 Alternative Depreciation System		
a. Class life		
b. 12-year		
c. 40-year		
Part IV - Summary		
21 Listed Property		
22 Total depreciation		
42 Amortization - current year		
43 Amortization - prior year		
44 Total Amortization		

SCANA CORPORATION 57-0784499

	Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
Consolidated Schedules				
Form 4797				
Column (g) Section 1231 Gains/Losses				
From Form 4797, line 2	-53,778,949.			-53,778,949.
Gain from Form 4684, line 39				
Gain from Form 6252				
From Form 8824				
Gain from Form 4797, line 32				
Total Section 1231 gain (loss)	-53,778,949.			-53,778,949.
Nonrecaptured prior year losses				
Net Section 1231 gain				
Ordinary Gains and Losses				
From Form 4797, line 10	-1,782,435.			-1,782,435.
Section 1231 loss	-53,780,595.		1,646.	-53,778,949.
Section 1231 gain				
Gain from Form 4797, line 31	3,789,467.			3,789,467.
From Form 4684				
From Form 6252				
From Form 8824				
Net ordinary gain or (loss)	-51,773,563.		1,646.	-51,771,917.

SCANA CORPORATION 57-0784499

	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA ENERGY MARKETING INC	SERVICECARE INC	PUBLIC SERVICE COMPANY OF NORTH
Consolidated Schedules Form 4797	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	57-0850977	57-1007394	56-2128483
Column (g) Section 1231 Gains/Losses								
From Form 4797, line 2		NONE	-39,991,222.		-3,530,135.	1,646.		-10,259,238.
Gain from Form 4684, line 39								
Gain from Form 6252								
From Form 8824								
Gain from Form 4797, line 32								
Total Section 1231 gain (loss)		NONE	-39,991,222.		-3,530,135.	1,646.		-10,259,238.
Nonrecaptured prior year losses								
Net Section 1231 gain								
Ordinary Gains and Losses								
From Form 4797, line 10		-696,096.	-1,015,942.					-70,397.
Section 1231 loss			-39,991,222.		-3,530,135.			-10,259,238.
Section 1231 gain								
Gain from Form 4797, line 31			2,982,956.					806,511.
From Form 4684								
From Form 6252								
From Form 8824								
Net ordinary gain or (loss)		-696,096.	-38,024,208.		-3,530,135.			-9,523,124.

SCANA CORPORATION 57-0784499

	CLEAN ENERGY ENTERPRISES INC	SCANA CORPORATE SECURITY SERVICES INC
Consolidated Schedules	56-1078443	20-0989017
Form 4797		
Column (g) Section 1231 Gains/Losses		
From Form 4797, line 2		
Gain from Form 4684, line 39		
Gain from Form 6252		
From Form 8824		
Gain from Form 4797, line 32		
Total Section 1231 gain (loss)		
Nonrecaptured prior year losses		
Net Section 1231 gain		
Ordinary Gains and Losses		
From Form 4797, line 10		
Section 1231 loss		
Section 1231 gain		
Gain from Form 4797, line 31		
From Form 4684		
From Form 6252		
From Form 8824		
Net ordinary gain or (loss)		

SCANA SERVICES INC 57-1092169

Form 4797, Page 1 Detail SCANA SERVICES INC

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS	07/01/2010	07/01/2016		233,786.	233,786.	NONE
Part I 4797 Gains and Losses						NONE

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Form 4797, Page 1 Detail SOUTH CAROLINA ELECTRIC and GAS COMPANY

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS			1,190,826.	34,778,065.	75,960,113.	-39,991,222.
Part I 4797 Gains and Losses						-39,991,222.

SC GENERATING COMPANY INC 57-0784498

Form 4797, Page 1 Detail SC GENERATING COMPANY INC

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS	VARIOUS	07/01/2016		2,089,073.	5,619,208.	-3,530,135.
Part I 4797 Gains and Losses						-3,530,135.

SCANA ENERGY MARKETING INC 57-0850977

Form 4797, Page 1 Detail SCANA ENERGY MARKETING INC

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
FURNITURE	06/30/2010	06/30/2016	1,646.	18,333.	18,333.	1,646.
Part I 4797 Gains and Losses						1,646.

Form 4797, Page 1 Detail PUBLIC SERVICE COMPANY OF NORTH CAROLINA

Line 2 - Most Property Held More Than 1 Year

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
Various	03/01/2015	07/01/2016	42,268.	7,072,408.	17,373,914.	-10,259,238.
Part I 4797 Gains and Losses						-10,259,238.

SCANA SERVICES INC 57-1092169

Form 4797, Page 1 Detail SCANA SERVICES INC

Line 10 - Ordinary Gains and Losses

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS2	07/01/2015	07/01/2016		391,554.	1,087,650.	-696,096.
Part II 4797 Ordinary Gains and Losses						-696,096.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Form 4797, Page 1 Detail SOUTH CAROLINA ELECTRIC and GAS COMPANY

Line 10 - Ordinary Gains and Losses

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
VARIOUS			1,368.	43,944.	1,061,254.	-1,015,942.
Part II 4797 Ordinary Gains and Losses						-1,015,942.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483

Form 4797, Page 1 Detail PUBLIC SERVICE COMPANY OF NORTH CAROLINA

Line 10 - Ordinary Gains and Losses

Property Description	Date Acq	Date Sold	Sales Price	Depreciation	Cost or Basis	Gain or Loss
Various	VARIOUS	07/01/2016	62,720.	5,392.	138,509.	-70,397.
Part II 4797 Ordinary Gains and Losses						-70,397.

SCANA CORPORATION 57-0784499

Form 6765 Page 1 Detail

Controlled Group Member Statement

Corporation Name	Share of Credit
SOUTH CAROLINA ELECTRIC and GAS COMPANY	28,137,821.
SC GENERATING COMPANY INC	7,586.

SCANA CORPORATION 57-0784499

Consolidated Schedules	Combined		ELIMINATIONS SCANA CORPORATIO		Adjustments		SCANA CORPORATION	
Form 8903	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities
1 Domestic production gross receipts		4,497,365,433.						4,497,365,433.
2 Allocable cost of goods sold		4,338,581,720.						4,338,581,720.
3 Deductions and losses		374,307,595.						374,307,595.
4 Pro rata share								
5 Add lines 2 through 4		4,712,889,315.						4,712,889,315.
6 Subtract line 5 from line 1		-215,523,882.						-215,523,882.
7 Qualified prod activities inc from pass-through								
8 Add lines 6 and 7.								
9 Amount allocated to beneficiaries of the estate or trust.								
10 Qualified production activities inc								
11 Income limitation								
12 Enter the smaller of line 10b or line 11								
13 Enter 9% of line 12								
14a Enter the smaller of line 10a or line 12								
b Reduction for oil-related QPAI								
15 Subtract line 14b from line 13								
16 Form W-2 wages								
17 Form W-2 wages from pass-through								
18 Add lines 16 and 17								
19 Amount allocated to beneficiaries of the estate or trust.								
20 Estates and trusts, subtract line 19 from line 18.								
21 Form W-2 wage limitation								
22 Enter the smaller of line 15 or line 21								
23 DPAD from cooperatives								
24 Expanded affiliated group allocation								
25 Domestic production activities ded								

SCANA CORPORATION 57-0784499

Consolidated Schedules	SCANA CORPORATION 57-0784499 Oil-related Pro	All Activities	SCANA SERVICES INC 57-1092169 Oil-related Pro	All Activities	SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695 Oil-related Pro	All Activities	SOUTH CAROLINA FUEL CO INC 57-0691209 Oil-related Pro	All Activities
Form 8903								
1 Domestic production gross receipts						4,497,365,433.		
2 Allocable cost of goods sold						4,338,581,720.		
3 Deductions and losses						374,307,595.		
4 Pro rata share								
5 Add lines 2 through 4						4,712,889,315.		
6 Subtract line 5 from line 1						-215,523,882.		
7 Qualified prod activities inc from pass-through								
8 Add lines 6 and 7.								
9 Amount allocated to beneficiaries of the estate or trust.								
10 Qualified production activities inc								
11 Income limitation								
12 Enter the smaller of line 10b or line 11								
13 Enter 9% of line 12								
14a Enter the smaller of line 10a or line 12								
b Reduction for oil-related QPAI								
15 Subtract line 14b from line 13								
16 Form W-2 wages								
17 Form W-2 wages from pass-through								
18 Add lines 16 and 17								
19 Amount allocated to beneficiaries of the estate or trust.								
20 Estates and trusts, subtract line 19 from line 18.								
21 Form W-2 wage limitation								
22 Enter the smaller of line 15 or line 21								
23 DPAD from cooperatives								
24 Expanded affiliated group allocation								
25 Domestic production activities ded								

SCANA CORPORATION 57-0784499

	SC GENERATING COMPANY INC		SCANA ENERGY MARKETING INC		SERVICECARE INC		PUBLIC SERVICE COMPANY OF NORTH CAROLINA	
	57-0784498		57-0850977		57-1007394		56-2128483	
Consolidated Schedules	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities	Oil-related Pro	All Activities
Form 8903								
1 Domestic production gross receipts								
2 Allocable cost of goods sold								
3 Deductions and losses								
4 Pro rata share								
5 Add lines 2 through 4								
6 Subtract line 5 from line 1								
7 Qualified prod activities inc from pass-through								
8 Add lines 6 and 7.								
9 Amount allocated to beneficiaries of the estate or trust.								
10 Qualified production activities inc								
11 Income limitation								
12 Enter the smaller of line 10b or line 11								
13 Enter 9% of line 12								
14a Enter the smaller of line 10a or line 12								
b Reduction for oil-related QPAI								
15 Subtract line 14b from line 13								
16 Form W-2 wages								
17 Form W-2 wages from pass-through								
18 Add lines 16 and 17								
19 Amount allocated to beneficiaries of the estate or trust.								
20 Estates and trusts, subtract line 19 from line 18.								
21 Form W-2 wage limitation								
22 Enter the smaller of line 15 or line 21								
23 DPAD from cooperatives								
24 Expanded affiliated group allocation								
25 Domestic production activities ded								

SCANA CORPORATION 57-0784499

Consolidated Schedules	CLEAN ENERGY ENTERPRISES INC 56-1078443		SCANA CORPORATE SECURITY SERVICES INC 20-0989017	
Form 8903	Oil-related Pro	All Activities	Oil-related Pro	All Activities
1 Domestic production gross receipts				
2 Allocable cost of goods sold				
3 Deductions and losses				
4 Pro rata share				
5 Add lines 2 through 4				
6 Subtract line 5 from line 1				
7 Qualified prod activities inc from pass-through				
8 Add lines 6 and 7.				
9 Amount allocated to beneficiaries of the estate or trust.				
10 Qualified production activities inc				
11 Income limitation				
12 Enter the smaller of line 10b or line 11				
13 Enter 9% of line 12				
14a Enter the smaller of line 10a or line 12				
b Reduction for oil-related QPAI				
15 Subtract line 14b from line 13				
16 Form W-2 wages				
17 Form W-2 wages from pass-through				
18 Add lines 16 and 17				
19 Amount allocated to beneficiaries of the estate or trust.				
20 Estates and trusts, subtract line 19 from line 18.				
21 Form W-2 wage limitation				
22 Enter the smaller of line 15 or line 21				
23 DPAD from cooperatives				
24 Expanded affiliated group allocation				
25 Domestic production activities ded				

SCANA CORPORATION 57-0784499

Form 8916-A, Part I Detail

Line 6 - Other items with differences

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
OTHER COSTS		-16,857,064.		-16,857,064.
Subtotal		-16,857,064.		-16,857,064.
SOUTH CAROLINA FUEL CO INC				
ELECTRIC - PRODUCTION	235,135,917.	-55,780,868.		179,355,049.
Subtotal	235,135,917.	-55,780,868.		179,355,049.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
OTHER COSTS	363,432.	-164,793.		198,639.
Subtotal	363,432.	-164,793.		198,639.
Total	235,499,349.	-72,802,725.		162,696,624.

SCANA CORPORATION 57-0784499

Form 8916-A, Part I Detail

Line 7 - Other items with no differences

SCANA SERVICES INC

ELECTRIC - DISTRIBUTION	1,851,944.
ELECTRIC - GENERAL	354,777.
ELECTRIC - PRODUCTION	5,945,786.
ELECTRIC - SALES PROMOTION	1,576,312.
ELECTRIC - TRANSMISSION	452,432.
GAS - CUSTOMER ACCOUNTS	60,665,935.
GAS - DISTRIBUTION	2,133,002.
GAS - PRODUCTION	840,817.
GAS - TRANSMISSION	211,713.
OTHER COSTS	285,470.
Subtotal	74,318,188.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

ELECTRIC - DISTRIBUTION	15,271,035.
ELECTRIC - GENERAL	-2,620,344.
ELECTRIC - PRODUCTION	826,249,729.
ELECTRIC - SALES PROMOTION	6,663,922.
ELECTRIC - TRANSMISSION	9,288,573.
GAS - CUSTOMER ACCOUNTS	53,410,559.
GAS - DISTRIBUTION	9,133,565.
GAS - PRODUCTION	184,185,087.
GAS - TRANSMISSION	235.
PURCHASES	3,783,559.
VACATION EXPENSE	-420,319.
Subtotal	1,104,945,601.

SC GENERATING COMPANY INC

ELECTRIC - GENERAL	4,966.
ELECTRIC - PRODUCTION	113,720,234.
Subtotal	113,725,200.

Continued on next page

SCANA CORPORATION 57-0784499

Form 8916-A, Part I Detail

Line 7 - Other items with no differences (Cont'd)

SCANA ENERGY MARKETING INC

ELECTRIC - GENERAL	128,082.
ELECTRIC - SALES PROMOTION	144,516.
GAS - CUSTOMER ACCOUNTS	13,131,414.
OTHER COSTS	120,236.
OTHER STORAGE EXPENSES	31,549,718.
PURCHASES	689,430,199.
TRANSPORTATION EXPENSES	77,549,781.
Subtotal	812,053,946.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA

ELECTRIC - GENERAL	729,521.
ELECTRIC - SALES PROMOTION	2,434,991.
GAS - CUSTOMER ACCOUNTS	12,489,629.
GAS - DISTRIBUTION	14,040,541.
GAS - PRODUCTION	1,350,844.
GAS - TRANSMISSION	3,574,987.
PURCHASES	170,203,331.
VACATION EXPENSE	-8,961.
Subtotal	204,814,883.

ELIMINATIONS SCANA CORPORATIO

ELECTRIC - DISTRIBUTION	-1,851,944.
ELECTRIC - GENERAL	-354,777.
ELECTRIC - PRODUCTION	-196,415,137.
ELECTRIC - SALES PROMOTION	-1,576,312.
ELECTRIC - TRANSMISSION	-452,432.
GAS - CUSTOMER ACCOUNTS	-60,665,935.
GAS - DISTRIBUTION	-2,133,002.
GAS - PRODUCTION	-840,817.
GAS - TRANSMISSION	-328,222.
OTHER COSTS	-285,470.
PURCHASES	-111,453,041.
Subtotal	-376,357,089.
Total	1,933,500,729.

Form 8916-A, Part II Detail

Line 5 - Other Interest Income

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SCANA CORPORATION				
INTEREST INCOME	1,595,218.	-1,382,225.		212,993.
Subtotal	1,595,218.	-1,382,225.		212,993.
SCANA SERVICES INC				
INTEREST INCOME	13,954.			13,954.
Subtotal	13,954.			13,954.
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
BOOK INTEREST CAPITALIZED	26,082,377.	203,397,097.		229,479,474.
INTEREST INCOME	5,862,694.			5,862,694.
Subtotal	31,945,071.	203,397,097.		235,342,168.

Continued on next page

SCANA CORPORATION 57-0784499

Form 8916-A, Part II Detail

Line 5 - Other Interest Income (Cont'd)

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SC GENERATING COMPANY INC				
BOOK INTEREST CAPITALIZED		-31,785.		-31,785.
INTEREST INCOME	54,017.			54,017.
Subtotal	54,017.	-31,785.		22,232.
SCANA ENERGY MARKETING INC				
INTEREST INCOME	221.			221.
Subtotal	221.			221.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
BOOK INTEREST CAPITALIZED	3,302,769.	-1,013,022.		2,289,747.
INTEREST INCOME	3,269,780.			3,269,780.
Subtotal	6,572,549.	-1,013,022.		5,559,527.

Continued on next page

Form 8916-A, Part II Detail

Line 5 - Other Interest Income (Cont'd)

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
ELIMINATIONS SCANA CORPORATIO				
INTEREST INCOME	-13,954.			-13,954.
Subtotal	-13,954.			-13,954.
Total	40,167,076.	200,970,065.		241,137,141.

SCANA CORPORATION 57-0784499

Form 8916-A, Part III Detail

Line 4 - Other Interest Expense

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SCANA CORPORATION				
OTHER INTEREST EXPENSE	54,743,724.	-3,597.		54,740,127.
Subtotal	54,743,724.	-3,597.		54,740,127.
SCANA SERVICES INC				
OTHER INTEREST EXPENSE	462.			462.
Subtotal	462.			462.
SOUTH CAROLINA ELECTRIC and GAS COMPANY				
OTHER INTEREST EXPENSE	248,048,905.	42,604,735.		290,653,640.
Subtotal	248,048,905.	42,604,735.		290,653,640.
SOUTH CAROLINA FUEL CO INC				
OTHER INTEREST EXPENSE	1,787,247.			1,787,247.
Subtotal	1,787,247.			1,787,247.

Continued on next page

SCANA CORPORATION 57-0784499

Form 8916-A, Part III Detail

Line 4 - Other Interest Expense (Cont'd)

Description	Per Income Stmt	Temporary Difference	Permanent Difference	Per Tax Return
SC GENERATING COMPANY INC				
OTHER INTEREST EXPENSE	14,133,651.	-482,617.		13,651,034.
Subtotal	14,133,651.	-482,617.		13,651,034.
SCANA ENERGY MARKETING INC				
OTHER INTEREST EXPENSE	-12,434.			-12,434.
Subtotal	-12,434.			-12,434.
PUBLIC SERVICE COMPANY OF NORTH CAROLINA				
OTHER INTEREST EXPENSE	24,154,282.	789,732.		24,944,014.
Subtotal	24,154,282.	789,732.		24,944,014.
ELIMINATIONS SCANA CORPORATIO				
OTHER INTEREST EXPENSE	-1,903,795.			-1,903,795.
Subtotal	-1,903,795.			-1,903,795.
Total	340,952,042.	42,908,253.		383,860,295.

Federal Elections

Description: Election RECURRING ITEMS EXCEPTION

Regulation Reference: 461(h)

Pursuant to Internal Revenue Code Section 461(h) and Regulation 1.461-5(D), the taxpayer has elected to use the recurring items exception to the economic performance rules of IRS Section 461(h), and intends for this election to apply to all subsidiaries included in the consolidated return. The election is adopted for all items satisfying the conditions outlined in Section 461(h) that are incurred in the taxpayer's trade or business.

Federal Elections

Description: Election DEPRECIATION UNDER IRC 168(k)

Regulation Reference: 168(k)

PURSUANT TO SECTION 168(K)(2)(C)(III), SCANA CORPORATION, AS AGENT FOR EACH OF ITS SUBSIDIARIES LISTED BELOW, HEREBY ELECTS NOT TO APPLY THE SPECIAL DEPRECIATION ALLOWANCE FOR CERTAIN PROPERTY ACQUIRED AFTER JANUARY 1, 2008, THAT IS PROVIDED UNDER SECTION 168(K) OF THE CODE, AND INTENDS FOR THIS ELECTION TO APPLY TO THE CLASSES OF QUALIFIED PROPERTY SEPARATELY LISTED ON A COMPANY BY COMPANY BASIS FOR THE TAX YEAR 2016. FOR SOUTH CAROLINA FUEL CO INC, THE ELECTION APPLIES TO ALL CLASSES OF QUALIFIED PROPERTY.

Federal Elections

Description: Election DEPRECIATION PRIOR TO JANUARY 1

Regulation Reference: 167

SCANA Corporation elects under Section 1.167(a)-12(e)(2) of the Regulations on behalf of itself and the following named subsidiaries to apply Section 1.167(a)-12 of the Regulations for depreciation of property placed in service prior to January 1, 1971 for the taxable year 2016. This election is for South Carolina Electric and Gas and Public Service Company of North Carolina, Inc.

☐ CORRECTED (if checked)

DONEE'S name, street address, city or town, state or province, country, ZIP or foreign postal code, and telephone no	1 Date of contribution	OMB No 1545-1959	Attachment Sequence No 155A
Calhoun County Rural Fire District 102 Courthouse Drive St Matthews, SC 29135	5-4-2016 2a Odometer mileage 221,648	2016 Form 1098-C	**Contributions of Motor Vehicles, Boats, and Airplanes**
	2b Year 2009 / 2c Make Chevrolet	2d Model CK 20753	
DONEE'S federal identification number 57-6000314 / DONOR'S identification number 57-0248695	3 Vehicle or other identification number 1GCHK49K99E152318		
DONOR'S name South Carolina Electric & Gas Co	4a ☐ Donee certifies that vehicle was sold in arm's length transaction to unrelated party		
Street address (including apt no) 100 SCANA Parkway	4b Date of sale		**Copy B**
City or town, state or province, country, and ZIP or foreign postal code Cayce, SC 29033	4c Gross proceeds from sale (see instructions) $		**For Donor**

5a ☑ Donee certifies that vehicle will not be transferred for money, other property, or services before completion of material improvements or significant intervening use

5b ☐ Donee certifies that vehicle is to be transferred to a needy individual for significantly below fair market value in furtherance of donee's charitable purpose

5c Donee certifies the following detailed description of material improvements or significant intervening use and duration of use

6a Did you provide goods or services in exchange for the vehicle? ▶ Yes ☐ No ☑

6b Value of goods and services provided in exchange for the vehicle
$

6c Describe the goods and services, if any, that were provided. If this box is checked, donee certifies that the goods and services consisted solely of intangible religious benefits ▶ ☐

7 Under the law, the donor may not claim a deduction of more than $500 for this vehicle if this box is checked ▶ ☐

In order to take a deduction of more than $500 for this contribution, you must attach this copy to your federal tax return.

Unless box 5a or 5b is checked, your deduction cannot exceed the amount in box 4c.

SCANA Corporation

57-0784499

Tax Year 2016

Schedule M-3, Page 3, Part 3, line 36
Section 118 Exclusion

Non Standard Service Fund $3,464,164 –Municipalities reimburse SCE&G costs for installing non-standard services. Typical work performed is for public benefit generally related to safety and beautification.

South Carolina Department of Transportation $9,029,018 – SCE&G is reimbursed cost for construction services provided to the SCDOT. These services typically include relocation projects involving removing and installing new SCE&G poles and/or lines and gas pipe to accommodate SCDOT improvement projects.

Form **1139** (Rev. November 2014) Department of the Treasury Internal Revenue Service

Corporation Application for Tentative Refund

▶ Information about Form 1139 and its separate instructions is at *www.irs.gov/form1139.*
▶ Do not file with the corporation's income tax return - file separately.
▶ Keep a copy of this application for your records.

OMB No. 1545-0123

Name: SCANA CORPORATION	Employer identification number: 57-0784499
Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY	Date of incorporation: 10/01/1984
City or town, state, and ZIP code: CAYCE, SC 29033-3701	Daytime phone number: (803) 217-9000

1 Reason(s) for filing. See instructions - attach computation
a Net operating loss (NOL) ▶ 57,112,028.
b Net capital loss ▶
c Unused general business credit Stmt. 71. ▶ 36,403,280.
d Other ▶

2 Return for year of loss, unused credit, or overpayment under section 1341(b)(1) ▶ a Tax year ended: 12/31/2016 b Date tax return filed: 09/28/2017 c Service center where filed:

3 If this application is for an unused credit created by another carryback, enter ending date for the tax year of the first carryback ▶

4 Did a loss result in the release of a foreign tax credit, or is the corporation carrying back a general business credit that was released because of the release of a foreign tax credit (see instructions)? If "Yes," the corporation must file an amended return to carry back the released credits ☐ Yes ☒ No

5a Was a consolidated return filed for any carryback year or did the corporation join a consolidated group (see instructions)? ☒ Yes ☐ No

b If "Yes," enter the tax year ending date and the name of the common parent and its EIN, if different from above (see instructions) ▶

6a If Form 1138 has been filed, was an extension of time granted for filing the return for the tax year of the NOL? ☐ Yes ☐ No

b If "Yes," enter the date to which extension was granted ▶ c Enter the date Form 1138 was filed. ▶

d Unpaid tax for which Form 1138 is in effect ▶ $

7 If the corporation changed its accounting period, enter the date permission to change was granted ▶

8 If this is an application for a dissolved corporation, enter date of dissolution ▶

9 Has the corporation filed a petition in Tax Court for the year or years to which the carryback is to be applied? ☐ Yes ☒ No

10 If any part of the decrease in tax due to a loss or credit resulting from a reportable transaction required to be disclosed? If Yes, attach Form 8886 ☐ Yes ☒ No

Computation of Decrease in Tax See instructions.	2nd preceding tax year ended ▶ 12/31/2014		1st preceding tax year ended ▶ 12/31/2015		preceding tax year ended ▶	
Note: *If only filing for an unused general business credit (line 1c), skip lines 11 through 15.*	(a) Before carryback	(b) After carryback	(c) Before carryback	(d) After carryback	(e) Before carryback	(f) After carryback
11 Taxable income from tax return	327491408.	332631490.	736424416.	736424416.		
12 Capital loss carryback (see instructions)						
13 Subtract line 12 from line 11		332631490.		736424416.		
14 NOL deduction (see instructions)		57112028.				
15 Taxable income. Subtract line 14 from line 13		275519462.		736424416.		
16 Income tax	114621993.	96431812.	257748546.	257748546.		
17 Alternative minimum tax						
18 Add lines 16 and 17	114621993.	96431812.	257748546.	257748546.		
19 General business credit (see instructions)	11207491.	11207491.	23454248.	59857528.		
20 Other credits (see instructions)			1,691.	1,691.		
21 Total credits. Add lines 19 and 20	11207491.	11207491.	23455939.	59859219.		
22 Subtract line 21 from line 18	103414502.	85224321.	234292607.	197889327.		
23 Personal holding company tax (Sch. PH (Form 1120))						
24 Other taxes (see instructions)						
25 Total tax liability. Add lines 22 through 24	103414502.	85224321.	234292607.	197889327.		
26 Enter amount from "After carryback" column on line 25 for each year	85224321.		197889327.			
27 Decrease in tax. Subtract line 26 from line 25	18190181.		36403280.			
28 Overpayment of tax due to a claim of right adjustment under section 1341(b)(1) (attach computation)						

Sign Here

Under penalties of perjury, I declare that I have examined this application and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete.

▶ Signature of officer JAMES E SWAN IV ▶ Date 10/18/2017 ▶ Title CONTROLLER

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

Form 1139, General Business Credit detail

Year	Amount	Year	Amount	Year	Amount
2001		2002		2003	
2004		2005		2006	
2007		2008		2009	
2010		2011		2012	
2013		2014		2015	

Total prior year General Business Credits	
Current year General Business Credit	36,403,280.
Total General Business Credits available	36,403,280.

Form **8302** (Rev. December 2009) Department of the Treasury Internal Revenue Service

Electronic Deposit of Tax Refund of $1 Million or More

▶ Attach to your income tax return (other than Forms 1040, 1120, or 1120S), Form 1045, or Form 1139.

OMB No. 1545-1763

Name(s) shown on income tax return	Identifying number
SCANA CORPORATION	57-0784499
Name and location (City, State) of bank	Taxpayer's phone number
WELLS FARGO BANK, SAN FRANCISCO, CA	8032179000

1 **Method of deposit (one box must be checked)** [X] Direct Deposit [ ] Fedwire

2 **Routing number** (must be nine digits). The first two digits must be between 01 and 12 or 21 through 32.

[redacted]

3 **Account number (include hyphens but omit spaces and special symbols):**

[redacted]

4 **Type of account (one box must be checked):**
[X] Checking [ ] Savings

General Instructions

Section references are to the Internal Revenue Code unless otherwise noted.

Purpose of Form

File Form 8302 to request that the IRS electronically deposit a tax refund of $1 million or more directly into an account at any U.S. bank or other financial institution (such as a mutual fund, credit union, or brokerage firm) that accepts electronic deposits.

The benefits of an electronic deposit include a faster refund, the added security of a paperless payment, and the savings of tax dollars associated with the reduced processing costs.

Who May File

Form 8302 may be filed with any tax return other than Form 1040, 1120, or 1120S to request an electronic deposit of a refund of $1 million or more. You are not eligible to request an electronic deposit if:

• The receiving financial institution is a foreign bank or a foreign branch of a U.S. bank or

• You have applied for an employer identification number but are filing your tax return before receiving one.

If Form 8302 is filed with **Form 1045,** Application for Tentative Refund, or **Form 1139,** Corporation Application for Tentative Refund, both of which allow for more than one year's reporting, electronic deposits may be made only for a year for which the refund is at least $1 million.

Note. *Filers of Form 1040 must request a direct deposit of refund by completing the account information on that form. Filers of Forms 1120 or 1120S must request a direct deposit of a refund using* ***Form 8050,*** *Direct Deposit of Corporate Tax Refund. This includes a request for a refund of $1 million or more.*

Conditions Resulting in a Refund by Check

If the IRS is unable to process this request for an electronic deposit, a refund by check will be generated. Reasons for not processing a request include:

• The name on the tax return does not match the name on the account.

• You fail to indicate the method of deposit to be used (i.e., direct deposit or Fedwire).

• The financial institution rejects the electronic deposit because of an incorrect routing or account number.

• You fail to indicate the type of account the deposit is to be made to (i.e., checking or savings).

• There is an outstanding liability the offset of which reduces the refund to less than $1 million.

How To File

Attach Form 8302 to the applicable return or application for refund. To ensure that your tax return is correctly processed, see **Assembling the Return** in the instructions for the form with which the Form 8302 is filed. For Forms 1045 or 1139, attach a separate Form 8302 for each carryback year.

Specific Instructions

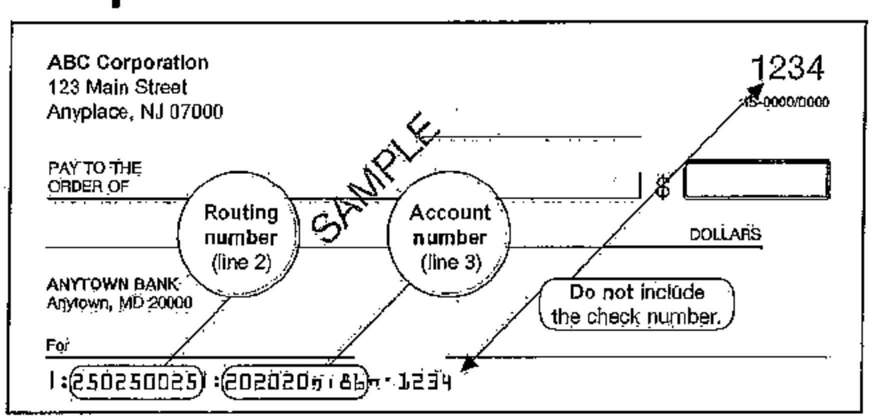
Identifying number. Enter the employer identification number or social security number shown on the tax return to which Form 8302 is attached.

Line 1. Direct deposit is an electronic payment alternative that uses the Automated Clearing House (ACH) system. Fedwire is a transaction-by-transaction processing system designed for items that must be received by payees the same day as originated by the IRS.

Line 2. Enter the financial institution's routing number and **verify** that the institution will accept the type of electronic deposit requested. See the Sample Check below for an example of where the routing number may be shown.

CAUTION: Check with your financial institution, if necessary, to verify the routing number entered on line 2 is correct.

Sample Check



Note. The routing and account numbers may be in different places on your check.

ISA

Form **8302**
(Rev. December 2009)
Department of the Treasury
Internal Revenue Service

Electronic Deposit of Tax Refund of $1 Million or More

▶ Attach to your income tax return (other than Forms 1040, 1120, or 1120S), Form 1045, or Form 1139.

OMB No. 1545-1763

Name(s) shown on income tax return	Identifying number
SCANA CORPORATION	57-0784499
Name and location (City, State) of bank	Taxpayer's phone number
WELLS FARGO BANK, SAN FRANCISCO, CA	8032179000

1 **Method of deposit (one box must be checked)** ☒ Direct Deposit ☐ Fedwire

2 **Routing number (must be nine digits).** The first two digits must be between 01 and 12 or 21 through 32.

[redacted]

3 **Account number (include hyphens but omit spaces and special symbols):**

[redacted]

4 **Type of account (one box must be checked):**
☒ Checking ☐ Savings

General Instructions

Section references are to the Internal Revenue Code unless otherwise noted.

Purpose of Form

File Form 8302 to request that the IRS electronically deposit a tax refund of $1 million or more directly into an account at any U.S. bank or other financial institution (such as a mutual fund, credit union, or brokerage firm) that accepts electronic deposits.

The benefits of an electronic deposit include a faster refund, the added security of a paperless payment, and the savings of tax dollars associated with the reduced processing costs.

Who May File

Form 8302 may be filed with any tax return other than Form 1040, 1120, or 1120S to request an electronic deposit of a refund of $1 million or more. You are not eligible to request an electronic deposit if:

• The receiving financial institution is a foreign bank or a foreign branch of a U.S. bank or

• You have applied for an employer identification number but are filing your tax return before receiving one.

If Form 8302 is filed with **Form 1045,** Application for Tentative Refund, or **Form 1139,** Corporation Application for Tentative Refund, both of which allow for more than one year's reporting, electronic deposits may be made only for a year for which the refund is at least $1 million.

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• The financial institution rejects the electronic deposit because of an incorrect routing or account number.

• You fail to indicate the type of account the deposit is to be made to (i.e., checking or savings).

• There is an outstanding liability the offset of which reduces the refund to less than $1 million.

How To File

Attach Form 8302 to the applicable return or application for refund. To ensure that your tax return is correctly processed, see **Assembling the Return** in the instructions for the form with which the Form 8302 is filed. For Forms 1045 or 1139, attach a separate Form 8302 for each carryback year.

Specific Instructions

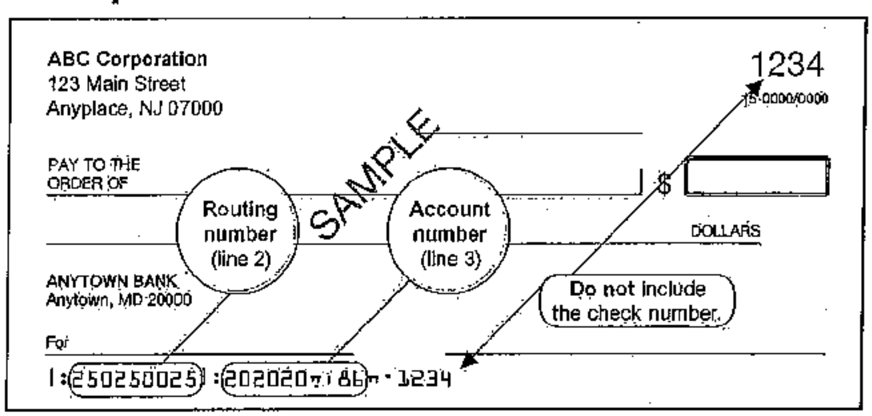
Identifying number. Enter the employer identification number or social security number shown on the tax return to which Form 8302 is attached.

Line 1. Direct deposit is an electronic payment alternative that uses the Automated Clearing House (ACH) system. Fedwire is a transaction-by-transaction processing system designed for items that must be received by payees the same day as originated by the IRS.

Line 2. Enter the financial institution's routing number and **verify** that the institution will accept the type of electronic deposit requested. See the Sample Check below for an example of where the routing number may be shown.

CAUTION: Check with your financial institution, if necessary, to verify the routing number entered on line 2 is correct.

Sample Check



Note. The routing and account numbers may be in different places on your check.

ISA

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2016 or tax year beginning ____________, ending ____________

▶ Information about Form 1120 and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2016

A Check if: 1a Consolidated return (attach Form 851) [X] b Life/nonlife consolidated return [ ] 2 Personal holding co. (attach Sch. PH) [ ] 3 Personal service corp. (see instructions) [ ] 4 Schedule M-3 attached [X]	Name: SCANA CORPORATION	B Employer identification number: 57-0784499
TYPE OR PRINT	Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY	C Date incorporated: 10/01/1984
	City or town, state, or province, country, and ZIP or foreign postal code: CAYCE, SC 29033-3701	D Total assets (see instructions): $ 18,706,879,069.

E Check if: (1) [ ] Initial return (2) [ ] Final return (3) [ ] Name change (4) [ ] Address change

	Line	Description			Line	Amount
Income	1a	Gross receipts or sales	1a	4,497,365,433.		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	4,497,365,433.
	2	Cost of goods sold (attach Form 1125-A)			2	2,118,180,744.
	3	Gross profit. Subtract line 2 from line 1c			3	2,379,184,689.
	4	Dividends (Schedule C, line 19)			4	337,492.
	5	Interest			5	241,238,458.
	6	Gross rents			6	15,809,392.
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	230,794.
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	-51,771,917.
	10	Other income (see instructions - attach statement) See Statement 4			10	27,496,341.
	11	Total income. Add lines 3 through 10 ▶			11	2,612,525,249.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E) ▶			12	15,144,833.
	13	Salaries and wages (less employment credits)			13	80,503,050.
	14	Repairs and maintenance			14	248,721,590.
	15	Bad debts			15	10,347,235.
	16	Rents			16	4,696,539.
	17	Taxes and licenses			17	256,620,275.
	18	Interest			18	385,177,623.
	19	Charitable contributions See Statement 6			19	NONE
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	674,906,524.
	21	Depletion			21	
	22	Advertising			22	12,485,413.
	23	Pension, profit-sharing, etc., plans			23	694,957.
	24	Employee benefit programs			24	56,802,808.
	25	Domestic production activities deduction (attach Form 8903)			25	
	26	Other deductions (attach statement) See Statement 7			26	923,324,230.
	27	Total deductions. Add lines 12 through 26 ▶			27	2,669,425,077.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11			28	-56,899,828.
	29a	Net operating loss deduction (see instructions)	29a	NONE	Stmt 10	
	b	Special deductions (Schedule C, line 20)	29b	212,200.		
	c	Add lines 29a and 29b			29c	212,200.
Tax, Refundable Credits, and Payments	30	Taxable income. Subtract line 29c from line 28. See instructions			30	-57,112,028.
	31	Total tax (Schedule J, Part I, line 11)			31	NONE
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	6,237,866.
	33	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶ [ ]			33	
	34	Amount owed. If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	
	35	Overpayment. If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	6,237,866.
	36	Enter amount from line 35 you want: Credited to 2017 estimated tax ▶		Refunded ▶	36	6,237,866.

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

▶ Signature of officer JAMES E SWAN IV | 09/28/2017 Date | ▶ CONTROLLER Title

May the IRS discuss this return with the preparer shown below? See instructions. [ ] Yes [X] No

Paid Preparer Use Only	Print/Type preparer's name	Preparer's signature	Date	Check [ ] if self-employed	PTIN
	Firm's name ▶			Firm's EIN ▶	
	Firm's address ▶			Phone no.	

SCANA CORPORATION 57-0784499
Form 1120 (2016) Page 2

Schedule C Dividends and Special Deductions (see instructions)	(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	303,143.	70	212,200.
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3 Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8 Dividends from wholly owned foreign subsidiaries		100	
9 Total. Add lines 1 through 8. See instructions for limitation			212,200.
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members		100	
12 Dividends from certain FSCs		100	
13 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, or 12	34,349.		
14 Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15 Foreign dividend gross-up			
16 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
17 Other dividends			
18 Deduction for dividends paid on certain preferred stock of public utilities			
19 Total dividends. Add lines 1 through 17. Enter here and on page 1, line 4 ▶	337,492.		
20 Total special deductions. Add lines 9, 10, 11, 12, and 18. Enter here and on page 1, line 29b ▶			212,200.

Form 1120 (2016)

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 3

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ ☐				
2	Income tax. Check if a qualified personal service corporation. See instructions ▶ ☐			2	
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	NONE
5a	Foreign tax credit (attach Form 1118)	5a			
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c			
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	Total credits. Add lines 5a through 5e			6	
7	Subtract line 6 from line 4			7	NONE
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	Total. Add lines 9a through 9f			10	
11	Total tax. Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	NONE

Part II-Payments and Refundable Credits

12	2015 overpayment credited to 2016			12	
13	2016 estimated tax payments			13	6,000,000.
14	2016 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	6,000,000.
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	Total payments. Add lines 15, 16, and 17			18	6,000,000.
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	237,866.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	Total credits. Add lines 19a through 19d			20	237,866.
21	Total payments and credits. Add lines 18 and 20. Enter here and on page 1, line 32			21	6,237,866.

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group?		X
	If "Yes," enter name and EIN of the parent corporation ▶		
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Form **4626**

Department of the Treasury
Internal Revenue Service

Alternative Minimum Tax - Corporations

▶ Attach to the corporation's tax return.

▶ Information about Form 4626 and its separate instructions is at *www.irs.gov/form4626*.

OMB No. 1545-0123

2016

Name	Employer identification number
SCANA CORPORATION	57-0784499

Note: *See the instructions to find out if the corporation is a small corporation exempt from the alternative minimum tax (AMT) under section 55(e).*

1	Taxable income or (loss) before net operating loss deduction			1	-57,112,028.
2	**Adjustments and preferences:**				
a	Depreciation of post-1986 property			2a	-22,424,670.
b	Amortization of certified pollution control facilities			2b	
c	Amortization of mining exploration and development costs			2c	
d	Amortization of circulation expenditures (personal holding companies only)			2d	
e	Adjusted gain or loss			2e	1,703,217.
f	Long-term contracts			2f	
g	Merchant marine capital construction funds			2g	
h	Section 833(b) deduction (Blue Cross, Blue Shield, and similar type organizations only)			2h	
i	Tax shelter farm activities (personal service corporations only)			2i	
j	Passive activities (closely held corporations and personal service corporations only)			2j	
k	Loss limitations			2k	
l	Depletion			2l	
m	Tax-exempt interest income from specified private activity bonds			2m	
n	Intangible drilling costs			2n	
o	Other adjustments and preferences See Statement 41			2o	NONE
3	Pre-adjustment alternative minimum taxable income (AMTI). Combine lines 1 through 2o			3	-77,833,481.
4	**Adjusted current earnings (ACE) adjustment:**				
a	ACE from line 10 of the ACE worksheet in the instructions	4a	-45,278,399.		
b	Subtract line 3 from line 4a. If line 3 exceeds line 4a, enter the difference as a negative amount. See instructions	4b	32,555,082.		
c	Multiply line 4b by 75% (0.75). Enter the result as a positive amount	4c	24,416,312.		
d	Enter the excess, if any, of the corporation's total increases in AMTI from prior year ACE adjustments over its total reductions in AMTI from prior year ACE adjustments. See instructions. **Note:** *You must enter an amount on line 4d (even if line 4b is positive)*	4d			
e	ACE adjustment. • If line 4b is zero or more, enter the amount from line 4c • If line 4b is less than zero, enter the **smaller** of line 4c or line 4d as a negative amount			4e	24,416,312.
5	Combine lines 3 and 4e. If zero or less, stop here; the corporation does not owe any AMT			5	-53,417,169.
6	Alternative tax net operating loss deduction. See instructions See Statement 43			6	
7	**Alternative minimum taxable income.** Subtract line 6 from line 5. If the corporation held a residual interest in a REMIC, see instructions			7	-53,417,169.
8	**Exemption phase-out** (if line 7 is $310,000 or more, skip lines 8a and 8b and enter -0- on line 8c):				
a	Subtract $150,000 from line 7 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-	8a	NONE		
b	Multiply line 8a by 25% (0.25)	8b	NONE		
c	Exemption. Subtract line 8b from $40,000 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-			8c	40,000.
9	Subtract line 8c from line 7. If zero or less, enter -0-			9	NONE
10	Multiply line 9 by 20% (0.20)			10	NONE
11	Alternative minimum tax foreign tax credit (AMTFTC). See instructions			11	
12	Tentative minimum tax. Subtract line 11 from line 10			12	NONE
13	Regular tax liability before applying all credits except the foreign tax credit			13	
14	**Alternative minimum tax.** Subtract line 13 from line 12. If zero or less, enter -0-. Enter here and on Form 1120, Schedule J, line 3, or the appropriate line of the corporation's income tax return			14	NONE

SCANA CORPORATION 57-0784499

Adjusted Current Earnings (ACE) Worksheet

Keep for Your Records

▶ See ACE Worksheet Instructions.

1	Pre-adjustment AMTI. Enter the amount from line 3 of Form 4626			1	-77,833,481.
2	ACE depreciation adjustment:				
a	AMT depreciation	2a	697,331,191.		
b	ACE depreciation:				
	(1) Post-1993 property — 2b(1) 244,943,932.				
	(2) Post-1989, pre-1994 property — 2b(2)				
	(3) Pre-1990 MACRS property — 2b(3)				
	(4) Pre-1990 original ACRS property — 2b(4)				
	(5) Property described in sections 168(f)(1) through (4) — 2b(5)				
	(6) Other property — 2b(6) 451,921,072.				
	(7) Total ACE depreciation. Add lines 2b(1) through 2b(6)	2b(7)	696,865,004.		
c	ACE depreciation adjustment. Subtract line 2b(7) from line 2a			2c	466,187.
3	Inclusion in ACE of items included in earnings and profits (E&P):				
a	Tax-exempt interest income	3a			
b	Death benefits from life insurance contracts	3b	-268,623.		
c	All other distributions from life insurance contracts (including surrenders)	3c			
d	Inside buildup of undistributed income in life insurance contracts	3d	4,986,147.		
e	Other items (see Regulations sections 1.56(g)-1(c)(6)(iii) through (ix) for a partial list)	3e			
f	Total increase to ACE from inclusion in ACE of items included in E&P. Add lines 3a through 3e			3f	4,717,524.
4	Disallowance of items not deductible from E&P:				
a	Certain dividends received	4a	212,200.		
b	Dividends paid on certain preferred stock of public utilities that are deductible under section 247 (as affected by P.L. 113-295, Div. A, section 221(a)(41)(A), Dec. 19, 2014, 128 Stat. 4043)	4b			
c	Dividends paid to an ESOP that are deductible under section 404(k)	4c	27,159,171.		
d	Nonpatronage dividends that are paid and deductible under section 1382(c)	4d			
e	Other items (see Regulations sections 1.56(g)-1(d)(3)(i) and (ii) for a partial list)	4e			
f	Total increase to ACE because of disallowance of items not deductible from E&P. Add lines 4a through 4e			4f	27,371,371.
5	Other adjustments based on rules for figuring E&P:				
a	Intangible drilling costs	5a			
b	Circulation expenditures	5b			
c	Organizational expenditures	5c			
d	LIFO inventory adjustments	5d			
e	Installment sales	5e			
f	Total other E&P adjustments. Combine lines 5a through 5e			5f	
6	Disallowance of loss on exchange of debt pools			6	
7	Acquisition expenses of life insurance companies for qualified foreign contracts			7	
8	Depletion			8	
9	Basis adjustments in determining gain or loss from sale or exchange of pre-1994 property			9	NONE
10	Adjusted current earnings. Combine lines 1, 2c, 3f, 4f, and 5f through 9. Enter the result here and on line 4a of Form 4626			10	-45,278,399.

Form **3800**
Department of the Treasury
Internal Revenue Service (99)

General Business Credit

▶ Information about Form 3800 and its separate instructions is at *www.irs.gov/form3800*.
▶ You must attach all pages of Form 3800, pages 1, 2, and 3, to your tax return.

OMB No. 1545-0895
2016
Attachment Sequence No. 22

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Part I Current Year Credit for Credits Not Allowed Against Tentative Minimum Tax (TMT)
(See instructions and complete Part(s) III before Parts I and II)

1	General business credit from line 2 of all Parts III with box A checked	1	28,148,334.
2	Passive activity credits from line 2 of all Parts III with box B checked [2]		
3	Enter the applicable passive activity credits allowed for 2016 (see instructions)	3	
4	Carryforward of general business credit to 2016. Enter the amount from line 2 of Part III with box C checked. See instructions for statement to attach	4	
5	Carryback of general business credit from 2017. Enter the amount from line 2 of Part III with box D checked (see instructions)	5	
6	Add lines 1, 3, 4, and 5	6	28,148,334.

Part II Allowable Credit

7	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46, or the sum of the amounts from Form 1040NR, lines 42 and 44 • Corporations. Enter the amount from Form 1120, Schedule J, Part I, line 2; or the applicable line of your return • Estates and trusts. Enter the sum of the amounts from Form 1041, Schedule G, lines 1a and 1b; or the amount from the applicable line of your return	7	
8	Alternative minimum tax: • Individuals. Enter the amount from Form 6251, line 35 • Corporations. Enter the amount from Form 4626, line 14 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 56	8	
9	Add lines 7 and 8	9	
10a	Foreign tax credit [10a]		
b	Certain allowable credits (see instructions) [10b]		
c	Add lines 10a and 10b	10c	
11	Net income tax. Subtract line 10c from line 9. If zero, skip lines 12 through 15 and enter -0- on line 16	11	
12	Net regular tax. Subtract line 10c from line 7. If zero or less, enter -0- [12]		
13	Enter 25% (.25) of the excess, if any, of line 12 over $25,000 (see instructions) [13]		
14	Tentative minimum tax: • Individuals. Enter the amount from Form 6251, line 33 • Corporations. Enter the amount from Form 4626, line 12 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 54 [14]		
15	Enter the greater of line 13 or line 14	15	
16	Subtract line 15 from line 11. If zero or less, enter -0-	16	
17	Enter the smaller of line 6 or line 16. C corporations: See the line 17 instructions if there has been an ownership change, acquisition, or reorganization.	17	

Form 3800 (2016) SCANA CORPORATION 57-0784499 Page 2

Part II **Allowable Credit** *(Continued)*

Note: If you are *not* required to report any amounts on lines 22 or 24 below, skip lines 18 through 25 and enter -0- on line 26.

18	Multiply line 14 by 75% (.75) (see instructions)	18	
19	Enter the greater of line 13 or line 18	19	
20	Subtract line 19 from line 11. If zero or less, enter -0-	20	
21	Subtract line 17 from line 20. If zero or less, enter -0-	21	
22	Combine the amounts from line 3 of all Parts III with box A, C, or D checked	22	
23	Passive activity credit from line 3 of all Parts III with box B checked [23]		
24	Enter the applicable passive activity credit allowed for 2016 (see instructions)	24	
25	Add lines 22 and 24	25	
26	Empowerment zone and renewal community employment credit allowed. Enter the smaller of line 21 or line 25	26	
27	Subtract line 13 from line 11. If zero or less, enter -0-	27	
28	Add lines 17 and 26	28	
29	Subtract line 28 from line 27. If zero or less, enter -0-	29	
30	Enter the general business credit from line 5 of all Parts III with box A checked	30	8,254,946.
31	Reserved	31	
32	Passive activity credits from line 5 of all Parts III with box B checked [32]		
33	Enter the applicable passive activity credits allowed for 2016 (see instructions)	33	
34	Carryforward of business credit to 2016. Enter the amount from line 5 of Part III with box C checked and line 6 of Part III with box G checked. See instructions for statement to attach	34	
35	Carryback of business credit from 2017. Enter the amount from line 5 of Part III with box D checked (see instructions)	35	
36	Add lines 30, 33, 34, and 35	36	8,254,946.
37	Enter the smaller of line 29 or line 36	37	
38	Credit allowed for the current year. Add lines 28 and 37. Report the amount from line 38 (if smaller than the sum of Part I, line 6, and Part II, lines 25 and 36, see instructions) as indicated below or on the applicable line of your return: • Individuals. Form 1040, line 54, or Form 1040NR, line 51 • Corporations. Form 1120, Schedule J, Part I, line 5c • Estates and trusts. Form 1041, Schedule G, line 2b	38	

Form 3800 (2016) Page 3

Name(s) shown on return: SCANA CORPORATION | Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below (see instructions).

- A [X] General Business Credit From a Non-Passive Activity
- B [ ] General Business Credit From a Passive Activity
- C [ ] General Business Credit Carryforwards
- D [ ] General Business Credit Carrybacks
- E [ ] Reserved
- F [ ] Reserved
- G [ ] Eligible Small Business Credit Carryforwards
- H [ ] Reserved

I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III ▶ [ ]

	(a) Description of credit Note: On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		28,145,407.
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel (carryforward only)	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance (carryforward only)	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		2,927.
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other. Enhanced oil recovery (Form 8830) and certain other credits	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		28,148,334.
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		8,254,946.
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Increasing research activities (Form 6765)	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		8,254,946.
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		36,403,280.

Form **6765**

Department of the Treasury
Internal Revenue Service

Credit for Increasing Research Activities

▶ Attach to your tax return.
▶ Information about Form 6765 and its separate instructions is at *www.irs.gov/form6765.*

OMB No. 1545-0619
2016
Attachment Sequence No. 81

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Section A - Regular Credit. Skip this section and go to Section B if you are electing or previously elected (and are not revoking) the alternative simplified credit.

Line	Description	Box	Amount	Line	Amount
1	Certain amounts paid or incurred to energy consortia (see instructions)			1	1,723,298.
2	Basic research payments to qualified organizations (see instructions)	2			
3	Qualified organization base period amount	3			
4	Subtract line 3 from line 2. If zero or less, enter -0-			4	
5	Wages for qualified services (do not include wages used in figuring the work opportunity credit)	5	2,585,567.		
6	Cost of supplies	6	9,839,450.		
7	Rental or lease costs of computers (see instructions)	7			
8	Enter the applicable percentage of contract research expenses (see instructions)	8	417,134,646.		
9	Total qualified research expenses. Add lines 5 through 8	9	429,559,663.		
10	Enter fixed-base percentage, but not more than 16% (0.16) (see instructions)	10	0.030 %		
11	Enter average annual gross receipts (see instructions)	11	5,039,022,108.		
12	Multiply line 11 by the percentage on line 10	12	1,511,707.		
13	Subtract line 12 from line 9. If zero or less, enter -0-	13	428,047,956.		
14	Multiply line 9 by 50% (0.50)	14	214,779,832.		
15	Enter the smaller of line 13 or line 14			15	214,779,832.
16	Add lines 1, 4, and 15			16	216,503,130.
17	Are you electing the reduced credit under section 280C? ▶ Yes [X] No [ ] If "Yes," multiply line 16 by 13% (0.13). If "No," multiply line 16 by 20% (0.20) and see the instructions for the statement that must be attached. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached Stmt 84			17	28,145,407.

Section B - Alternative Simplified Credit. Skip this section if you are completing Section A.

Line	Description	Box	Amount	Line	Amount
18	Certain amounts paid or incurred to energy consortia (see the line 1 instructions)			18	
19	Basic research payments to qualified organizations (see the line 2 instructions)	19			
20	Qualified organization base period amount (see the line 3 instructions)	20			
21	Subtract line 20 from line 19. If zero or less, enter -0-			21	
22	Add lines 18 and 21			22	
23	Multiply line 22 by 20% (0.20)			23	
24	Wages for qualified services (do not include wages used in figuring the work opportunity credit)	24			
25	Cost of supplies	25			
26	Rental or lease costs of computers (see the line 7 instructions)	26			
27	Enter the applicable percentage of contract research expenses (see the line 8 instructions)	27			
28	Total qualified research expenses. Add lines 24 through 27	28			
29	Enter your total qualified research expenses for the prior 3 tax years. If you had no qualified research expenses in any one of those years, skip lines 30 and 31	29			
30	Divide line 29 by 6.0	30			
31	Subtract line 30 from line 28. If zero or less, enter -0-	31			
32	Multiply line 31 by 14% (0.14). If you skipped lines 30 and 31, multiply line 28 by 6% (0.06)			32	

For Paperwork Reduction Act Notice, see separate instructions.

SCANA CORPORATION 57-0784499

Section B - Alternative Simplified Credit *(continued)*

33	Add lines 23 and 32	33	
34	Are you electing the reduced credit under section 280C? ▶ Yes ☐ No ☐ If "Yes," multiply line 33 by 65% (0.65). If "No," enter the amount from line 33 and see the line 17 instructions for the statement that must be attached. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached	34	

Section C - Current Year Credit

35	Enter the portion of the credit from Form 8932, line 2, that is attributable to wages that were also used to figure the credit on line 17 or line 34 (whichever applies)	35	
36	Subtract line 35 from line 17 or line 34 (whichever applies). If zero or less, enter -0-	36	28,145,407.
37	Credit for increasing research activities from partnerships, S corporations, estates, and trusts	37	
38	Add lines 36 and 37	38	28,145,407.
	• Estates and trusts, go to line 39. • Partnerships and S corporations not electing the payroll tax credit, stop here and report this amount on Schedule K. • Partnerships and S corporations electing the payroll tax credit, complete Section D and report on Schedule K the amount on this line reduced by the amount on line 44. • Eligible small businesses, stop here and report the credit on Form 3800, Part III, line 4i. See instructions for the definition of eligible small business. • Filers other than eligible small businesses, stop here and report the credit on Form 3800, Part III, line 1c. **Note:** Qualified small business filers, other than partnerships and S corporations, electing the payroll tax credit must complete Form 3800 before completing Section D.		
39	Amount allocated to beneficiaries of the estate or trust (see instructions)	39	
40	Estates and trusts, subtract line 39 from line 38. For eligible small businesses, report the credit on Form 3800, Part III, line 4i. See instructions. For filers other than eligible small businesses, report the credit on Form 3800, Part III, line 1c	40	

Section D - Qualified Small Business Payroll Tax Election and Payroll Tax Credit. Skip this section if the payroll tax election does not apply. See instructions.

41	Check this box if you are a qualified small business electing the payroll tax credit. See instructions ☐		
42	Enter the portion of line 36 elected as a payroll tax credit (do not enter more than $250,000). See instructions	42	
43	General business credit carryforward from the current year (see instructions). Partnerships and S corporations skip this line and go to line 44	43	
44	Partnerships and S corporations, enter the smaller of line 36 or line 42. All others, enter the smallest of line 36, line 42, or line 43. Enter here and on Form 8974, line 5. Members of controlled groups or businesses under common control: see instructions for the statement that must be attached	44	

Form **8835**

Department of the Treasury
Internal Revenue Service

Renewable Electricity, Refined Coal, and Indian Coal Production Credit

▶ Attach to your tax return.
▶ Information about Form 8835 and its separate instructions is at *www.irs.gov/form8835*.

OMB No. 1545-1362
2016
Attachment Sequence No. **95**

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Electricity and Refined Coal Produced at Qualified Facilities Placed in Service After October 22, 2004 (After October 2, 2008, for Electricity Produced From Marine and Hydrokinetic Renewables), and Indian Coal Produced at Facilities Placed in Service After August 8, 2005

			(a) Kilowatt-hours produced and sold (see instructions)	(b) Rate	(c) Column (a) x Column (b)		
1	Electricity produced at qualified facilities using:						
a	Wind	1a		0.023			
b	Closed-loop biomass	1b		0.023			
c	Geothermal	1c		0.023			
d	Solar	1d		0.023			
e	Add column (c) of lines 1a through 1d and enter here (see instructions)					1e	
2	Electricity produced at qualified facilities using:						
a	Open-loop biomass	2a		0.012			
b	Small irrigation power	2b		0.012			
c	Landfill gas	2c		0.012			
d	Trash	2d		0.012			
e	Hydropower	2e		0.012			
f	Marine and hydrokinetic renewables	2f		0.012			
g	Add column (c) of lines 2a through 2f and enter here (see instructions)					2g	

3	Add lines 1e and 2g		3	
4	Phaseout adjustment (see instructions)	$ x	4	
5	Subtract line 4 from line 3		5	
	Refined coal produced at a qualified refined coal production facility			
6	Tons produced and sold (see instructions)	1212180 x $6.810	6	8,254,946.
7	Phaseout adjustment (see instructions)	$ x	7	
8	Subtract line 7 from line 6		8	8,254,946.
9	Reserved		9	
	Indian coal produced at a qualified Indian coal production facility			
10	Tons produced and sold (see instructions)	x $2.387	10	
11	Credit before reduction. Add lines 5, 8, and 10		11	8,254,946.
	Reduction for government grants, subsidized financing, and other credits:			
12	Total of government grants, proceeds of tax-exempt government obligations, subsidized energy financing, and any federal tax credits allowed for the project for this and all prior tax years (see instructions)		12	
13	Total of additions to the capital account for the project for this and all prior tax years		13	
14	Divide line 12 by line 13. Show as a decimal carried to at least 4 places		14	
15	Multiply line 11 by the smaller of 1/2 or line 14		15	
16	Subtract line 15 from line 11		16	8,254,946.
17a	Enter the amount from line 16 applicable to wind facilities the construction of which began during 2017		17a	
b	Multiply line 17a by 20% (0.20)		17b	
18	Subtract line 17b from line 16		18	8,254,946.
19	Renewable electricity, refined coal, and Indian coal production credit from partnerships, S corporations, cooperatives, estates, and trusts (see instructions)		19	
20	Add lines 18 and 19. Cooperatives, estates, and trusts, go to line 21. Partnerships and S corporations, stop here and report this amount on Schedule K. All others: For electricity or refined coal produced during the 4-year period beginning on the date the facility was placed in service or Indian coal produced, stop here and report the applicable part of this amount on Form 3800, Part III, line 4e. For all other production of electricity or refined coal, stop here and report the applicable part of this amount on Form 3800, Part III, line 1f (see instructions)		20	8,254,946.
21	Amount allocated to patrons of the cooperative or beneficiaries of the estate or trust (see instructions)		21	
22	Cooperatives, estates, and trusts, subtract line 21 from line 20. For electricity or refined coal produced during the 4-year period beginning on the date the facility was placed in service or Indian coal produced, report the applicable part of this amount on Form 3800, Part III, line 4e. For all other production of electricity or refined coal, report the applicable part of this amount on Form 3800, Part III, line 1f		22	

Form **8911**

Department of the Treasury
Internal Revenue Service

Alternative Fuel Vehicle Refueling Property Credit

▶ Attach to your tax return.
▶ Information about Form 8911 and its instructions is at *www.irs.gov/form8911.*

OMB No. 1545-1981
2016
Attachment Sequence No. 151

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Part I Total Cost of Refueling Property

1	Total cost of qualified alternative fuel vehicle refueling property placed in service during the tax year (see **What's New** in the instructions)	1	9,755.

Part II Credit for Business/Investment Use Part of Refueling Property

2	Business/investment use part (see instructions)	2	9,755.
3	Section 179 expense deduction (see instructions)	3	
4	Subtract line 3 from line 2	4	9,755.
5	Multiply line 4 by 30% (0.30)	5	2,927.
6	Maximum business/investment use part of credit (see instructions)	6	2,927.
7	Enter the smaller of line 5 or line 6	7	2,927.
8	Alternative fuel vehicle refueling property credit from partnerships and S corporations (see instructions)	8	
9	**Business/investment use part of credit.** Add lines 7 and 8. Partnerships and S corporations, stop here and report this amount on Schedule K. All others, report this amount on Form 3800, Part III, line 1s	9	2,927.

Part III Credit for Personal Use Part of Refueling Property

10	Subtract line 2 from line 1. If zero, stop here; **do not** file this form unless you are claiming a credit on line 9	10	
11	Multiply line 10 by 30% (0.30)	11	
12	Maximum personal use part of credit (see instructions)	12	
13	Enter the smaller of line 11 or line 12	13	
14	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46; or the sum of the amounts from Form 1040NR, lines 42 and 44. • Other filers. Enter the regular tax before credits from your return.	14	
15	Credits that reduce regular tax before the alternative fuel vehicle refueling property credit:		
a	Foreign tax credit — 15a		
b	Certain allowable credits (see instructions) — 15b		
c	Add lines 15a and 15b	15c	
16	**Net regular tax.** Subtract line 15c from line 14. If zero or less, enter -0- and stop here; **do not** file this form unless you are claiming a credit on line 9	16	
17	Tentative minimum tax (see instructions): • Individuals. Enter the amount from Form 6251, line 33. • Other filers. Enter the tentative minimum tax from your alternative minimum tax form or schedule.	17	
18	Subtract line 17 from line 16. If zero or less, stop here; **do not** file this form unless you are claiming a credit on line 9	18	
19	**Personal use part of credit.** Enter the smaller of line 13 or line 18 here and on Form 1040, line 54; Form 1040NR, line 51; or the appropriate line of your return. If line 18 is smaller than line 13, see instructions	19	

Revised for 1139 - 2016 NOL Carryback

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2014 or tax year beginning ____________, ending ____________

▶ Information about Form 1120 and its separate instructions is at *www.irs.gov/form1120.*

OMB No. 1545-0123

2014

A Check if:
1a Consolidated return (attach Form 851) [X]
b Life/nonlife consolidated return [ ]
2 Personal holding co. (attach Sch. PH) [ ]
3 Personal service corp. (see instructions) [ ]
4 Schedule M-3 attached [X]

TYPE OR PRINT

Name: SCANA CORPORATION
Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY
City or town, state, or province, country and ZIP or foreign postal code: CAYCE SC 29033-3701

B Employer identification number: 57-0784499
C Date incorporated: 10/01/1984
D Total assets (see instructions): $ 16,282,065,479

E Check if: (1) [ ] Initial return (2) [ ] Final return (3) [ ] Name change (4) [ ] Address change

Section	Line	Description			Line	Amount
Income	1a	Gross receipts or sales	1a	5,340,586,654		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	5,340,586,654
	2	Cost of goods sold (attach Form 1125-A)			2	3,188,618,650
	3	Gross profit. Subtract line 2 from line 1c			3	2,151,968,004
	4	Dividends (Schedule C, line 19)			4	255,738
	5	Interest			5	4,887,996
	6	Gross rents			6	12,995,121
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	0
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	-38,498,702
	10	Other income (see instructions—attach statement) See Stmt 1			10	69,405,234
	11	**Total income.** Add lines 3 through 10 ▶			11	2,201,013,391
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions—attach Form 1125-E) ▶			12	15,919,473
	13	Salaries and wages (less employment credits)			13	81,901,461
	14	Repairs and maintenance			14	335,612,445
	15	Bad debts			15	14,437,847
	16	Rents			16	3,312,662
	17	Taxes and licenses See Stmt 2			17	245,236,141
	18	Interest			18	243,995,772
	19	Charitable contributions			19	12,902,153
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	599,499,128
	21	Depletion			21	
	22	Advertising			22	12,438,775
	23	Pension, profit-sharing, etc., plans			23	845,117
	24	Employee benefit programs			24	70,928,822
	25	Domestic production activities deduction (attach Form 8903)			25	27,249,178
	26	Other deductions (attach statement) See Stmt 3			26	203,923,910
	27	**Total deductions.** Add lines 12 through 26 ▶			27	1,868,202,884
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11.			28	332,810,507
	29a	Net operating loss deduction (see instructions) See Stmt 4	29a	57,112,028		
	b	Special deductions (Schedule C, line 20)	29b	179,017		
	c	Add lines 29a and 29b			29c	57,291,045
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28 (see instructions)			30	275,519,462
	31	Total tax (Schedule J, Part I, line 11)			31	85,224,321
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	233,412,118
	33	Estimated tax penalty (see instructions). Check if Form 2220 is attached ▶ [X]			33	
	34	**Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	NONE
	35	**Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	148,187,797
	36	Enter amount from line 35 you want: Credited to 2015 estimated tax ▶ 129,997,616 Refunded ▶			36	18,190,181

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer | Date: 09/09/2015 | Title: CONTROLLER

May the IRS discuss this return with the preparer shown below (see instructions)? [ ] Yes [ ] No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check [ ] if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

Schedule J Tax Computation and Payment (see instructions)

Part I–Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)) ▶ ☐				
2	Income tax. Check if a qualified personal service corporation (see instructions) ▶ ☐			2	96,431,812
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	96,431,812
5a	Foreign tax credit (attach Form 1118)	5a			
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	11,207,491		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	11,207,491
7	Subtract line 6 from line 4			7	85,224,321
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method—completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method—income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions—attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	NONE
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	85,224,321

Part II–Payments and Refundable Credits

12	2013 overpayment credited to 2014			12	46,151,859
13	2014 estimated tax payments			13	187,000,000
14	2014 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	233,151,859
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	**Total payments.** Add lines 15, 16, and 17			18	233,151,859
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	260,259		
c	Form 8827, line 8c	19c			
d	Other (attach statement—see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	260,259
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	233,412,118

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Form **4626**

Department of the Treasury
Internal Revenue Service

Alternative Minimum Tax—Corporations

▶ Attach to the corporation's tax return.
▶ Information about Form 4626 and its separate instructions is at *www.irs.gov/form4626*.

OMB No. 1545-0123

2014

Name	Employer identification number
SCANA CORPORATION	57-0784499

Note: *See the instructions to find out if the corporation is a small corporation exempt from the alternative minimum tax (AMT) under section 55(e).*

1	Taxable income or (loss) before net operating loss deduction			1	332,631,490
2	**Adjustments and preferences:**				
a	Depreciation of post-1986 property			2a	-29,753,910
b	Amortization of certified pollution control facilities			2b	
c	Amortization of mining exploration and development costs			2c	
d	Amortization of circulation expenditures (personal holding companies only)			2d	
e	Adjusted gain or loss			2e	3,104,493
f	Long-term contracts			2f	
g	Merchant marine capital construction funds			2g	
h	Section 833(b) deduction (Blue Cross, Blue Shield, and similar type organizations only)			2h	
i	Tax shelter farm activities (personal service corporations only)			2i	
j	Passive activities (closely held corporations and personal service corporations only)			2j	
k	Loss limitations			2k	
l	Depletion			2l	
m	Tax-exempt interest income from specified private activity bonds			2m	
n	Intangible drilling costs			2n	
o	Other adjustments and preferences			2o	
3	Pre-adjustment alternative minimum taxable income (AMTI). Combine lines 1 through 2o			3	305,982,073
4	**Adjusted current earnings (ACE) adjustment:**				
a	ACE from line 10 of the ACE worksheet in the instructions	4a	340,852,378		
b	Subtract line 3 from line 4a. If line 3 exceeds line 4a, enter the difference as a negative amount (see instructions)	4b	34,870,305		
c	Multiply line 4b by 75% (.75). Enter the result as a positive amount	4c	26,152,729		
d	Enter the excess, if any, of the corporation's total increases in AMTI from prior year ACE adjustments over its total reductions in AMTI from prior year ACE adjustments (see instructions). **Note:** *You* ***must*** *enter an amount on line 4d (even if line 4b is positive)*	4d	118,564,616		
e	ACE adjustment. • If line 4b is zero or more, enter the amount from line 4c • If line 4b is less than zero, enter the **smaller** of line 4c or line 4d as a negative amount			4e	26,152,729
5	Combine lines 3 and 4e. If zero or less, stop here; the corporation does not owe any AMT			5	332,134,802
6	Alternative tax net operating loss deduction (see instructions)			6	53,417,169
7	**Alternative minimum taxable income.** Subtract line 6 from line 5. If the corporation held a residual interest in a REMIC, see instructions			7	278,717,633
8	**Exemption phase-out** (if line 7 is $310,000 or more, skip lines 8a and 8b and enter -0- on line 8c):				
a	Subtract $150,000 from line 7 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-	8a			
b	Multiply line 8a by 25% (.25)	8b			
c	Exemption. Subtract line 8b from $40,000 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-			8c	0
9	Subtract line 8c from line 7. If zero or less, enter -0-			9	278,717,633
10	Multiply line 9 by 20% (.20)			10	55,743,527
11	Alternative minimum tax foreign tax credit (AMTFTC) (see instructions)			11	
12	Tentative minimum tax. Subtract line 11 from line 10			12	55,743,527
13	Regular tax liability before applying all credits except the foreign tax credit			13	96,431,812
14	**Alternative minimum tax.** Subtract line 13 from line 12. If zero or less, enter -0-. Enter here and on Form 1120, Schedule J, line 3, or the appropriate line of the corporation's income tax return			14	0

Adjusted Current Earnings (ACE) Worksheet

▶ See ACE Worksheet Instructions. (which begin on page 8).

1	Pre-adjustment AMTI. Enter the amount from line 3 of Form 4626					1	305,982,073
2	ACE depreciation adjustment:						
a	AMT depreciation			2a	629,253,038		
b	ACE depreciation:						
	(1) Post-1993 property	2b(1)					
	(2) Post-1989, pre-1994 property	2b(2)					
	(3) Pre-1990 MACRS property	2b(3)					
	(4) Pre-1990 original ACRS property	2b(4)					
	(5) Property described in sections 168(f)(1) through (4)	2b(5)					
	(6) Other property	2b(6)	633,504,022				
	(7) Total ACE depreciation. Add lines 2b(1) through 2b(6)			2b(7)	633,504,022		
c	ACE depreciation adjustment. Subtract line 2b(7) from line 2a					2c	-4,250,984
3	Inclusion in ACE of items included in earnings and profits (E&P):						
a	Tax-exempt interest income			3a			
b	Death benefits from life insurance contracts			3b	1,121,643		
c	All other distributions from life insurance contracts (including surrenders)			3c			
d	Inside buildup of undistributed income in life insurance contracts			3d	9,137,883		
e	Other items (see Regulations sections 1.56(g)-1(c)(6)(iii) through (ix) for a partial list)			3e			
f	Total increase to ACE from inclusion in ACE of items included in E&P. Add lines 3a through 3e					3f	10,259,526
4	Disallowance of items not deductible from E&P:						
a	Certain dividends received			4a	179,017		
b	Dividends paid on certain preferred stock of public utilities that are deductible under section 247			4b			
c	Dividends paid to an ESOP that are deductible under section 404(k)			4c	28,682,746		
d	Nonpatronage dividends that are paid and deductible under section 1382(c)			4d			
e	Other items (see Regulations sections 1.56(g)-1(d)(3)(i) and (ii) for a partial list)			4e			
f	Total increase to ACE because of disallowance of items not deductible from E&P. Add lines 4a through 4e					4f	28,861,763
5	Other adjustments based on rules for figuring E&P:						
a	Intangible drilling costs			5a			
b	Circulation expenditures			5b			
c	Organizational expenditures			5c			
d	LIFO inventory adjustments			5d			
e	Installment sales			5e			
f	Total other E&P adjustments. Combine lines 5a through 5e					5f	0
6	Disallowance of loss on exchange of debt pools					6	
7	Acquisition expenses of life insurance companies for qualified foreign contracts					7	
8	Depletion					8	
9	Basis adjustments in determining gain or loss from sale or exchange of pre-1994 property					9	
10	**Adjusted current earnings.** Combine lines 1, 2c, 3f, 4f, and 5f through 9. Enter the result here and on line 4a of Form 4626					10	340,852,378

For Paperwork Reduction Act Notice, See Instructions.

Form **8903** (Rev. December 2010) Department of the Treasury Internal Revenue Service

Domestic Production Activities Deduction

▶ Attach to your tax return. ▶ See separate instructions.

OMB No. 1545-1984

Attachment Sequence No. 143

Name(s) as shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Note. Do not complete column (a), unless you have oil-related production activities. Enter amounts for all activities in column (b), including oil-related production activities.		(a) Oil-related production activities	(b) All activities
1 Domestic production gross receipts (DPGR)	1		3,309,040,328
2 Allocable cost of goods sold. If you are using the small business simplified overall method, skip lines 2 and 3	2		2,927,379,858
3 Enter deductions and losses allocable to DPGR (see instructions)	3		8,230,446
4 If you are using the small business simplified overall method, enter the amount of cost of goods sold and other deductions or losses you ratably apportion to DPGR. All others, skip line 4	4		
5 Add lines 2 through 4	5		2,935,610,304
6 Subtract line 5 from line 1	6		373,430,024
7 Qualified production activities income from estates, trusts, and certain partnerships and S corporations (see instructions)	7		
8 Add lines 6 and 7. Estates and trusts, go to line 9, all others, skip line 9 and go to line 10	8	0	373,430,024
9 Amount allocated to beneficiaries of the estate or trust (see instructions)	9		
10a **Oil-related qualified production activities income.** Estates and trusts, subtract line 9, column (a), from line 8, column (a), all others, enter amount from line 8, column (a). If zero or less, enter -0- here.	10a	0	
b **Qualified production activities income.** Estates and trusts, subtract line 9, column (b), from line 8, column (b), all others, enter amount from line 8, column (b). If zero or less, enter -0- here, skip lines 11 through 21, and enter -0- on line 22	10b		373,430,024

11 Income limitation (see instructions): • Individuals, estates, and trusts. Enter your adjusted gross income figured without the domestic production activities deduction • All others. Enter your taxable income figured without the domestic production activities deduction (tax-exempt organizations, see instructions)	11	302,768,640
12 Enter the smaller of line 10b or line 11. If zero or less, enter -0- here, skip lines 13 through 21, and enter -0- on line 22	12	302,768,640
13 Enter 9% of line 12	13	27,249,178
14a Enter the smaller of line 10a or line 12 — 14a		
b Reduction for oil-related qualified production activities income. Multiply line 14a by 3%	14b	
15 Subtract line 14b from line 13	15	27,249,178
16 Form W-2 wages (see instructions)	16	856,826,997
17 Form W-2 wages from estates, trusts, and certain partnerships and S corporations (see instructions)	17	
18 Add lines 16 and 17. Estates and trusts, go to line 19, all others, skip line 19 and go to line 20	18	856,826,997
19 Amount allocated to beneficiaries of the estate or trust (see instructions)	19	
20 Estates and trusts, subtract line 19 from line 18, all others, enter amount from line 18	20	856,826,997
21 Form W-2 wage limitation. Enter 50% of line 20	21	428,413,499
22 Enter the smaller of line 15 or line 21	22	27,249,178
23 Domestic production activities deduction from cooperatives. Enter deduction from Form 1099-PATR, box 6	23	
24 Expanded affiliated group allocation (see instructions)	24	
25 **Domestic production activities deduction.** Combine lines 22 through 24 and enter the result here and on Form 1040, line 35; Form 1120, line 25; or the applicable line of your return	25	27,249,178

Original

OMB No. 1545-0123

Form **1120**

Department of the Treasury
Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2014 or tax year beginning ____________, ending ____________

▶ Information about Form 1120 and its separate instructions is at www.irs.gov/form1120.

2014

A Check if:	TYPE OR PRINT		
1a Consolidated return (attach Form 851) ☒		Name: SCANA CORPORATION	B Employer identification number: 57-0784499
b Life/nonlife consolidated return ☐		Number, street, and room or suite no. If a P.O. box, see instructions: 220 OPERATION WAY	C Date incorporated: 10/01/1984
2 Personal holding co. (attach Sch. PH) ☐		City or town, state, or province, country and ZIP or foreign postal code: CAYCE SC 29033-3701	D Total assets (see instructions): $ 16,282,065,479
3 Personal service corp. (see instructions) ☐			
4 Schedule M-3 attached ☒		E Check if: (1) ☐ Initial return (2) ☐ Final return (3) ☐ Name change (4) ☐ Address change	

Section	Line	Description		Amount	Line	Amount
Income	1a	Gross receipts or sales	1a	5,340,586,654		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	5,340,586,654
	2	Cost of goods sold (attach Form 1125-A)			2	3,188,618,650
	3	Gross profit. Subtract line 2 from line 1c			3	2,151,968,004
	4	Dividends (Schedule C, line 19)			4	255,738
	5	Interest			5	4,887,996
	6	Gross rents			6	12,995,121
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	0
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	-38,498,702
	10	Other income (see instructions—attach statement) See Stmt 1			10	69,405,234
	11	**Total income.** Add lines 3 through 10 ▶			11	2,201,013,391
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions—attach Form 1125-E) ▶			12	15,919,473
	13	Salaries and wages (less employment credits)			13	81,901,461
	14	Repairs and maintenance			14	335,612,445
	15	Bad debts			15	14,437,847
	16	Rents			16	3,312,662
	17	Taxes and licenses See Stmt 2			17	245,236,141
	18	Interest			18	243,995,772
	19	Charitable contributions			19	12,902,153
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	599,499,128
	21	Depletion			21	
	22	Advertising			22	12,438,775
	23	Pension, profit-sharing, etc., plans			23	845,117
	24	Employee benefit programs			24	70,928,822
	25	Domestic production activities deduction (attach Form 8903)			25	32,389,260
	26	Other deductions (attach statement) See Stmt 3			26	203,923,910
	27	**Total deductions.** Add lines 12 through 26 ▶			27	1,873,342,966
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11.			28	327,670,425
	29a	Net operating loss deduction (see instructions)	29a			
	b	Special deductions (Schedule C, line 20)	29b	179,017		
	c	Add lines 29a and 29b			29c	179,017
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28 (see instructions)			30	327,491,408
	31	Total tax (Schedule J, Part I, line 11)			31	103,414,502
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	233,412,118
	33	Estimated tax penalty (see instructions). Check if Form 2220 is attached ▶ ☒			33	
	34	**Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	NONE
	35	**Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	129,997,616
	36	Enter amount from line 35 you want: **Credited to 2015 estimated tax** ▶ 129,997,616 **Refunded** ▶			36	NONE

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

▶ Signature of officer ____ Date: 09/09/2015 ▶ Title: CONTROLLER

May the IRS discuss this return with the preparer shown below (see instructions)? ☐ Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

Schedule J **Tax Computation and Payment** (see instructions)

Part I–Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)) ▶ ☐				
2	Income tax. Check if a qualified personal service corporation (see instructions) ▶ ☐			2	114,621,993
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	114,621,993
5a	Foreign tax credit (attach Form 1118)	5a			
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	11,207,491		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	11,207,491
7	Subtract line 6 from line 4			7	103,414,502
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method—completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method—income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions—attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	NONE
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	103,414,502

Part II–Payments and Refundable Credits

12	2013 overpayment credited to 2014			12	46,151,859
13	2014 estimated tax payments			13	187,000,000
14	2014 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	233,151,859
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	**Total payments.** Add lines 15, 16, and 17			18	233,151,859
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	260,259		
c	Form 8827, line 8c	19c			
d	Other (attach statement—see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	260,259
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	233,412,118

Schedule K **Other Information** (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Form **4626** Department of the Treasury Internal Revenue Service

Alternative Minimum Tax—Corporations

OMB No. 1545-0123

2014

▶ Attach to the corporation's tax return.
▶ Information about Form 4626 and its separate instructions is at *www.irs.gov/form4626*.

Name	Employer identification number
SCANA CORPORATION	57-0784499

Note: *See the instructions to find out if the corporation is a small corporation exempt from the alternative minimum tax (AMT) under section 55(e).*

1	Taxable income or (loss) before net operating loss deduction			1	327,491,408
2	**Adjustments and preferences:**				
a	Depreciation of post-1986 property			2a	-29,753,910
b	Amortization of certified pollution control facilities			2b	
c	Amortization of mining exploration and development costs			2c	
d	Amortization of circulation expenditures (personal holding companies only)			2d	
e	Adjusted gain or loss			2e	3,104,493
f	Long-term contracts			2f	
g	Merchant marine capital construction funds			2g	
h	Section 833(b) deduction (Blue Cross, Blue Shield, and similar type organizations only)			2h	
i	Tax shelter farm activities (personal service corporations only)			2i	
j	Passive activities (closely held corporations and personal service corporations only)			2j	
k	Loss limitations			2k	
l	Depletion			2l	
m	Tax-exempt interest income from specified private activity bonds			2m	
n	Intangible drilling costs			2n	
o	Other adjustments and preferences			2o	
3	Pre-adjustment alternative minimum taxable income (AMTI). Combine lines 1 through 2o			3	300,841,991
4	**Adjusted current earnings (ACE) adjustment:**				
a	ACE from line 10 of the ACE worksheet in the instructions	4a	335,712,296		
b	Subtract line 3 from line 4a. If line 3 exceeds line 4a, enter the difference as a negative amount (see instructions)	4b	34,870,305		
c	Multiply line 4b by 75% (.75). Enter the result as a positive amount	4c	26,152,729		
d	Enter the excess, if any, of the corporation's total increases in AMTI from prior year ACE adjustments over its total reductions in AMTI from prior year ACE adjustments (see instructions). **Note:** *You* ***must*** *enter an amount on line 4d (even if line 4b is positive).*	4d	118,564,616		
e	ACE adjustment. • If line 4b is zero or more, enter the amount from line 4c • If line 4b is less than zero, enter the **smaller** of line 4c or line 4d as a negative amount			4e	26,152,729
5	Combine lines 3 and 4e. If zero or less, stop here; the corporation does not owe any AMT			5	326,994,720
6	Alternative tax net operating loss deduction (see instructions)			6	
7	**Alternative minimum taxable income.** Subtract line 6 from line 5. If the corporation held a residual interest in a REMIC, see instructions			7	326,994,720
8	**Exemption phase-out** (if line 7 is $310,000 or more, skip lines 8a and 8b and enter -0- on line 8c):				
a	Subtract $150,000 from line 7 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-	8a			
b	Multiply line 8a by 25% (.25)	8b			
c	Exemption. Subtract line 8b from $40,000 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-			8c	0
9	Subtract line 8c from line 7. If zero or less, enter -0-			9	326,994,720
10	Multiply line 9 by 20% (.20)			10	65,398,944
11	Alternative minimum tax foreign tax credit (AMTFTC) (see instructions)			11	
12	Tentative minimum tax. Subtract line 11 from line 10			12	65,398,944
13	Regular tax liability before applying all credits except the foreign tax credit			13	114,621,993
14	**Alternative minimum tax.** Subtract line 13 from line 12. If zero or less, enter -0-. Enter here and on Form 1120, Schedule J, line 3, or the appropriate line of the corporation's income tax return			14	0

SCANA CORPORATION 57-0784499

Adjusted Current Earnings (ACE) Worksheet

▶ See ACE Worksheet Instructions. (which begin on page 8).

Line	Description						
1	Pre-adjustment AMTI. Enter the amount from line 3 of Form 4626					1	300,841,991
2	ACE depreciation adjustment:						
a	AMT depreciation			2a	629,253,038		
b	ACE depreciation.						
	(1) Post-1993 property	2b(1)					
	(2) Post-1989, pre-1994 property	2b(2)					
	(3) Pre-1990 MACRS property	2b(3)					
	(4) Pre-1990 original ACRS property	2b(4)					
	(5) Property described in sections 168(f)(1) through (4)	2b(5)					
	(6) Other property	2b(6)	633,504,022				
	(7) Total ACE depreciation. Add lines 2b(1) through 2b(6)			2b(7)	633,504,022		
c	ACE depreciation adjustment. Subtract line 2b(7) from line 2a					2c	-4,250,984
3	Inclusion in ACE of items included in earnings and profits (E&P):						
a	Tax-exempt interest income			3a			
b	Death benefits from life insurance contracts			3b	1,121,643		
c	All other distributions from life insurance contracts (including surrenders)			3c			
d	Inside buildup of undistributed income in life insurance contracts			3d	9,137,883		
e	Other items (see Regulations sections 1.56(g)-1(c)(6)(iii) through (ix) for a partial list)			3e			
f	Total increase to ACE from inclusion in ACE of items included in E&P. Add lines 3a through 3e					3f	10,259,526
4	Disallowance of items not deductible from E&P:						
a	Certain dividends received			4a	179,017		
b	Dividends paid on certain preferred stock of public utilities that are deductible under section 247			4b			
c	Dividends paid to an ESOP that are deductible under section 404(k)			4c	28,682,746		
d	Nonpatronage dividends that are paid and deductible under section 1382(c)			4d			
e	Other items (see Regulations sections 1.56(g)-1(d)(3)(i) and (ii) for a partial list)			4e			
f	Total increase to ACE because of disallowance of items not deductible from E&P. Add lines 4a through 4e					4f	28,861,763
5	Other adjustments based on rules for figuring E&P:						
a	Intangible drilling costs			5a			
b	Circulation expenditures			5b			
c	Organizational expenditures			5c			
d	LIFO inventory adjustments			5d			
e	Installment sales			5e			
f	Total other E&P adjustments. Combine lines 5a through 5e					5f	0
6	Disallowance of loss on exchange of debt pools					6	
7	Acquisition expenses of life insurance companies for qualified foreign contracts					7	
8	Depletion					8	
9	Basis adjustments in determining gain or loss from sale or exchange of pre-1994 property					9	
10	**Adjusted current earnings.** Combine lines 1, 2c, 3f, 4f, and 5f through 9. Enter the result here and on line 4a of Form 4626					10	335,712,296

For Paperwork Reduction Act Notice, See Instructions.

JXB F 02/10/05

Form **8903** (Rev. December 2010) Department of the Treasury Internal Revenue Service

Domestic Production Activities Deduction

▶ Attach to your tax return. ▶ See separate instructions.

OMB No. 1545-1984

Attachment Sequence No. 143

Name(s) as shown on return	Identifying number
SCANA CORPORATION	57-0784499

Note. Do not complete column (a), unless you have oil-related production activities. Enter amounts for all activities in column (b), including oil-related production activities.		(a) Oil-related production activities	(b) All activities
1 Domestic production gross receipts (DPGR)	1		3,309,040,328
2 Allocable cost of goods sold. If you are using the small business simplified overall method, skip lines 2 and 3	2		2,927,379,858
3 Enter deductions and losses allocable to DPGR (see instructions)	3		8,230,446
4 If you are using the small business simplified overall method, enter the amount of cost of goods sold and other deductions or losses you ratably apportion to DPGR. All others, skip line 4	4		
5 Add lines 2 through 4	5		2,935,610,304
6 Subtract line 5 from line 1	6		373,430,024
7 Qualified production activities income from estates, trusts, and certain partnerships and S corporations (see instructions)	7		
8 Add lines 6 and 7. Estates and trusts, go to line 9, all others, skip line 9 and go to line 10	8	0	373,430,024
9 Amount allocated to beneficiaries of the estate or trust (see instructions)	9		
10a **Oil-related qualified production activities income.** Estates and trusts, subtract line 9, column (a), from line 8, column (a), all others, enter amount from line 8, column (a). If zero or less, enter -0- here.	10a	0	
b **Qualified production activities income.** Estates and trusts, subtract line 9, column (b), from line 8, column (b), all others, enter amount from line 8, column (b). If zero or less, enter -0- here, skip lines 11 through 21, and enter -0- on line 22	10b		373,430,024

11 Income limitation (see instructions): • Individuals, estates, and trusts. Enter your adjusted gross income figured without the domestic production activities deduction • All others. Enter your taxable income figured without the domestic production activities deduction (tax-exempt organizations, see instructions)	11	359,880,668
12 Enter the smaller of line 10b or line 11. If zero or less, enter -0- here, skip lines 13 through 21, and enter -0- on line 22	12	359,880,668
13 Enter 9% of line 12	13	32,389,260
14a Enter the smaller of line 10a or line 12 — 14a		
b Reduction for oil-related qualified production activities income. Multiply line 14a by 3%	14b	
15 Subtract line 14b from line 13	15	32,389,260
16 Form W-2 wages (see instructions)	16	856,826,997
17 Form W-2 wages from estates, trusts, and certain partnerships and S corporations (see instructions)	17	
18 Add lines 16 and 17. Estates and trusts, go to line 19, all others, skip line 19 and go to line 20	18	856,826,997
19 Amount allocated to beneficiaries of the estate or trust (see instructions)	19	
20 Estates and trusts, subtract line 19 from line 18, all others, enter amount from line 18	20	856,826,997
21 Form W-2 wage limitation. Enter 50% of line 20	21	428,413,499
22 Enter the smaller of line 15 or line 21.	22	32,389,260
23 Domestic production activities deduction from cooperatives. Enter deduction from Form 1099-PATR, box 6	23	
24 Expanded affiliated group allocation (see instructions)	24	
25 **Domestic production activities deduction.** Combine lines 22 through 24 and enter the result here and on Form 1040, line 35; Form 1120, line 25; or the applicable line of your return	25	32,389,260

Revised for 1139 - 2016 Carryback

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2015 or tax year beginning ______, ending ______

▶ Information about Form 1120 and its separate instructions is at www.irs.gov/form1120.

OMB No. 1545-0123

2015

A Check if:	Name	B Employer identification number
1a Consolidated return (attach Form 851) ☒	SCANA CORPORATION	57-0784499
b Life/nonlife consolidated return ☐	Number, street, and room or suite no. If a P.O. box, see instructions.	C Date incorporated
2 Personal holding co. (attach Sch. PH) ☐	220 OPERATION WAY	10/01/1984
3 Personal service corp. (see instructions) ☐	City or town, state, or province, country, and ZIP or foreign postal code	D Total assets (see instructions)
4 Schedule M-3 attached ☒	CAYCE SC 29033-3701	$ 16,789,419,184

E Check if: (1) ☐ Initial return (2) ☐ Final return (3) ☐ Name change (4) ☐ Address change

Section	Line	Description			Line	Amount
Income	1a	Gross receipts or sales	1a	4,752,235,717		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	4,752,235,717
	2	Cost of goods sold (attach Form 1125-A)			2	2,483,622,176
	3	Gross profit. Subtract line 2 from line 1c			3	2,268,613,541
	4	Dividends (Schedule C, line 19)			4	284,021
	5	Interest			5	4,628,851
	6	Gross rents			6	15,869,608
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	145,167,238
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	320,352,950
	10	Other income (see instructions—attach statement) See Stmt 1			10	38,753,671
	11	**Total income.** Add lines 3 through 10 ▶			11	2,793,669,880
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions—attach Form 1125-E) ▶			12	13,893,341
	13	Salaries and wages (less employment credits)			13	82,769,216
	14	Repairs and maintenance			14	257,510,775
	15	Bad debts			15	13,178,603
	16	Rents			16	3,628,032
	17	Taxes and licenses See Stmt 2			17	262,493,786
	18	Interest			18	142,982,968
	19	Charitable contributions			19	10,485,294
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	628,145,399
	21	Depletion			21	
	22	Advertising			22	12,300,363
	23	Pension, profit-sharing, etc., plans			23	1,437,241
	24	Employee benefit programs			24	58,192,611
	25	Domestic production activities deduction (attach Form 8903)			25	24,496,822
	26	Other deductions (attach statement) See Stmt 3			26	545,532,198
	27	**Total deductions.** Add lines 12 through 26 ▶			27	2,057,046,649
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11.			28	736,623,231
	29a	Net operating loss deduction (see instructions)	29a			
	b	Special deductions (Schedule C, line 20)	29b	198,815		
	c	Add lines 29a and 29b			29c	198,815
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28 (see instructions)			30	736,424,416
	31	Total tax (Schedule J, Part I, line 11)			31	197,889,327
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	400,220,311
	33	Estimated tax penalty (see instructions). Check if Form 2220 is attached ▶ ☒			33	
	34	**Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	NONE
	35	**Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	202,330,984
	36	Enter amount from line 35 you want: **Credited to 2016 estimated tax** ▶ NONE **Refunded** ▶			36	202,330,984

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer ______ Date 09/13/2016 ▶ Title CONTROLLER

May the IRS discuss this return with the preparer shown below (see instructions)? ☒ Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
TERRY R HUGGINS		09/13/2016		P00969508
Firm's name ▶ ERNST & YOUNG US LLP			Firm's EIN ▶ 34-6565596	
Firm's address ▶ 2 WEST WASHINGTON STREET GREENVILLE SC 29601			Phone no. (864) 242-5740	

Schedule J Tax Computation and Payment (see instructions)

Part I–Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)) ▶ ☐				
2	Income tax. Check if a qualified personal service corporation (see instructions) ▶ ☐			2	257,748,546
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	257,748,546
5a	Foreign tax credit (attach Form 1118)	5a	1,691		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	59,857,528		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	59,859,219
7	Subtract line 6 from line 4			7	197,889,327
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method—completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method—income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions—attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	NONE
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	197,889,327

Part II–Payments and Refundable Credits

12	2014 overpayment credited to 2015			12	129,997,616
13	2015 estimated tax payments			13	145,000,000
14	2015 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	274,997,616
16	Tax deposited with Form 7004			16	125,000,000
17	Withholding (see instructions)			17	
18	**Total payments.** Add lines 15, 16, and 17			18	399,997,616
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	222,695		
c	Form 8827, line 8c	19c			
d	Other (attach statement—see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	222,695
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	400,220,311

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Form **4626**

Department of the Treasury
Internal Revenue Service

Alternative Minimum Tax—Corporations

▶ Attach to the corporation's tax return.
▶ Information about Form 4626 and its separate instructions is at *www.irs.gov/form4626.*

OMB No. 1545-0123

2015

Name	Employer identification number
SCANA CORPORATION	57-0784499

Note: *See the instructions to find out if the corporation is a small corporation exempt from the alternative minimum tax (AMT) under section 55(e).*

1	Taxable income or (loss) before net operating loss deduction			1	736,424,416
2	**Adjustments and preferences:**				
a	Depreciation of post-1986 property			2a	-23,690,934
b	Amortization of certified pollution control facilities			2b	
c	Amortization of mining exploration and development costs			2c	
d	Amortization of circulation expenditures (personal holding companies only)			2d	
e	Adjusted gain or loss			2e	7,325,297
f	Long-term contracts			2f	
g	Merchant marine capital construction funds			2g	
h	Section 833(b) deduction (Blue Cross, Blue Shield, and similar type organizations only)			2h	
i	Tax shelter farm activities (personal service corporations only)			2i	
j	Passive activities (closely held corporations and personal service corporations only)			2j	
k	Loss limitations			2k	
l	Depletion			2l	
m	Tax-exempt interest income from specified private activity bonds			2m	
n	Intangible drilling costs			2n	
o	Other adjustments and preferences			2o	
3	Pre-adjustment alternative minimum taxable income (AMTI). Combine lines 1 through 2o			3	720,058,779
4	**Adjusted current earnings (ACE) adjustment:**				
a	ACE from line 10 of the ACE worksheet in the instructions	4a	745,332,480		
b	Subtract line 3 from line 4a. If line 3 exceeds line 4a, enter the difference as a negative amount (see instructions)	4b	25,273,701		
c	Multiply line 4b by 75% (.75). Enter the result as a positive amount	4c	18,955,276		
d	Enter the excess, if any, of the corporation's total increases in AMTI from prior year ACE adjustments over its total reductions in AMTI from prior year ACE adjustments (see instructions). **Note:** *You* ***must*** *enter an amount on line 4d (even if line 4b is positive)*	4d	144,717,345		
e	ACE adjustment. • If line 4b is zero or more, enter the amount from line 4c • If line 4b is less than zero, enter the **smaller** of line 4c or line 4d as a negative amount			4e	18,955,276
5	Combine lines 3 and 4e. If zero or less, stop here; the corporation does not owe any AMT			5	739,014,055
6	Alternative tax net operating loss deduction (see instructions)			6	
7	**Alternative minimum taxable income.** Subtract line 6 from line 5. If the corporation held a residual interest in a REMIC, see instructions			7	739,014,055
8	**Exemption phase-out** (if line 7 is $310,000 or more, skip lines 8a and 8b and enter -0- on line 8c):				
a	Subtract $150,000 from line 7 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-	8a			
b	Multiply line 8a by 25% (.25)	8b			
c	Exemption. Subtract line 8b from $40,000 (if completing this line for a member of a controlled group, see instructions). If zero or less, enter -0-			8c	0
9	Subtract line 8c from line 7. If zero or less, enter -0-			9	739,014,055
10	Multiply line 9 by 20% (.20)			10	147,802,811
11	Alternative minimum tax foreign tax credit (AMTFTC) (see instructions)			11	
12	Tentative minimum tax. Subtract line 11 from line 10			12	147,802,811
13	Regular tax liability before applying all credits except the foreign tax credit			13	257,746,855
14	**Alternative minimum tax.** Subtract line 13 from line 12. If zero or less, enter -0-. Enter here and on Form 1120, Schedule J, line 3, or the appropriate line of the corporation's income tax return			14	0

Form **3800**

Department of the Treasury
Internal Revenue Service (99)

General Business Credit

▶ Information about Form 3800 and its separate instructions is at *www.irs.gov/form3800.*
▶ You must attach all pages of Form 3800, pages 1, 2, and 3, to your tax return.

OMB No. 1545-0895
2015
Attachment Sequence No. 22

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part I Current Year Credit for Credits Not Allowed Against Tentative Minimum Tax (TMT)
(See instructions and complete Part(s) III before Parts I and II)

1	General business credit from line 2 of all Parts III with box A checked			1	14,703,607
2	Passive activity credits from line 2 of all Parts III with box B checked	2			
3	Enter the applicable passive activity credits allowed for 2015 (see instructions)			3	0
4	Carryforward of general business credit to 2015. Enter the amount from line 2 of Part III with box C checked. See instructions for statement to attach			4	
5	Carryback of general business credit from 2016. Enter the amount from line 2 of Part III with box D checked (see instructions)			5	28,148,334
6	Add lines 1, 3, 4, and 5			6	42,851,941

Part II Allowable Credit

7	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46, or the sum of the amounts from Form 1040NR, lines 42 and 44 • Corporations. Enter the amount from Form 1120, Schedule J, Part I, line 2; or the applicable line of your return • Estates and trusts. Enter the sum of the amounts from Form 1041, Schedule G, lines 1a and 1b; or the amount from the applicable line of your return			7	257,748,546
8	Alternative minimum tax: • Individuals. Enter the amount from Form 6251, line 35 • Corporations. Enter the amount from Form 4626, line 14 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 56			8	NONE
9	Add lines 7 and 8			9	257,748,546
10a	Foreign tax credit	10a	1,691		
b	Certain allowable credits (see instructions)	10b			
c	Add lines 10a and 10b			10c	1,691
11	**Net income tax.** Subtract line 10c from line 9. If zero, skip lines 12 through 15 and enter -0- on line 16			11	257,746,855
12	**Net regular tax.** Subtract line 10c from line 7. If zero or less, enter -0-	12	257,746,855		
13	Enter 25% (.25) of the excess, if any, of line 12 over $25,000 (see instructions)	13	64,430,464		
14	Tentative minimum tax: • Individuals. Enter the amount from Form 6251, line 33 • Corporations. Enter the amount from Form 4626, line 12 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 54	14	147,802,811		
15	Enter the greater of line 13 or line 14			15	147,802,811
16	Subtract line 15 from line 11. If zero or less, enter -0-			16	109,944,044
17	Enter the **smaller** of line 6 or line 16 **C corporations:** See the line 17 instructions if there has been an ownership change, acquisition, or reorganization.			17	42,851,941

SCANA CORPORATION 57-0784499

Part II **Allowable Credit** *(Continued)*

Note. If you are not required to report any amounts on lines 22 or 24 below, skip lines 18 through 25 and enter -0- on line 26.

18	Multiply line 14 by 75% (.75) (see instructions)	18	
19	Enter the greater of line 13 or line 18	19	
20	Subtract line 19 from line 11. If zero or less, enter -0-	20	0
21	Subtract line 17 from line 20. If zero or less, enter -0-	21	0
22	Combine the amounts from line 3 of all Parts III with box A, C, or D checked	22	0
23	Passive activity credit from line 3 of all Parts III with box B checked 23 0		
24	Enter the applicable passive activity credit allowed for 2015 (see instructions)	24	0
25	Add lines 22 and 24	25	0
26	Empowerment zone and renewal community employment credit allowed. Enter the smaller of line 21 or line 25	26	0
27	Subtract line 13 from line 11. If zero or less, enter -0-	27	193,316,391
28	Add lines 17 and 26	28	42,851,941
29	Subtract line 28 from line 27. If zero or less, enter -0-	29	150,464,450
30	Enter the general business credit from line 5 of all Parts III with box A checked	30	8,750,641
31	Reserved	31	
32	Passive activity credits from line 5 of all Parts III with box B checked 32 0		
33	Enter the applicable passive activity credits allowed for 2015 (see instructions)	33	0
34	Carryforward of business credit to 2015. Enter the amount from line 5 of Part III with box C checked and line 6 of Part III with box G checked. See instructions for statement to attach	34	0
35	Carryback of business credit from 2016. Enter the amount from line 5 of Part III with box D checked (see instructions)	35	8,254,946
36	Add lines 30, 33, 34, and 35	36	17,005,587
37	Enter the **smaller** of line 29 or line 36	37	17,005,587
38	**Credit allowed for the current year.** Add lines 28 and 37. Report the amount from line 38 (if smaller than the sum of Part I, line 6, and Part II, lines 25 and 36, see instructions) as indicated below or on the applicable line of your return: • Individuals. Form 1040, line 54, or Form 1040NR, line 51 • Corporations. Form 1120, Schedule J, Part I, line 5c • Estates and trusts. Form 1041, Schedule G, line 2b	38	59,857,528

Form 3800 (2015) Page 3

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

A ☐ General Business Credit From a Non-Passive Activity
B ☐ General Business Credit From a Passive Activity
C ☐ General Business Credit Carryforwards
D ☐ General Business Credit Carrybacks
E ☐ Reserved
F ☐ Reserved
G ☐ Eligible Small Business Credit Carryforwards
H ☐ Reserved
I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III . . . ▶ ☒

	(a) Description of credit Note. On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		14,581,384
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
~~f~~	~~Renewable electricity, refined coal, and Indian coal production (Form 8835)~~	~~1f~~		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		122,223
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		14,703,607
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		8,750,641
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		8,750,641
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		23,454,248

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

- A ☒ General Business Credit From a Non-Passive Activity
- B ☐ General Business Credit From a Passive Activity
- C ☐ General Business Credit Carryforwards
- D ☐ General Business Credit Carrybacks
- E ☐ Reserved
- F ☐ Reserved
- G ☐ Eligible Small Business Credit Carryforwards
- H ☐ Reserved

I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III ▶ ☐

	(a) Description of credit **Note.** On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		14,581,384
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		122,223
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		14,703,607
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		14,703,607

Form 3800 (2015) Page 3

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

A ☒ General Business Credit From a Non-Passive Activity
B ☐ General Business Credit From a Passive Activity
C ☐ General Business Credit Carryforwards
D ☐ General Business Credit Carrybacks
E ☐ Reserved
F ☐ Reserved
G ☐ Eligible Small Business Credit Carryforwards
H ☐ Reserved

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	(a) Description of credit Note. On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e	27-1302931	6,630,033
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		6,630,033
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		6,630,033

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

- A ☒ General Business Credit From a Non-Passive Activity
- B ☐ General Business Credit From a Passive Activity
- C ☐ General Business Credit Carryforwards
- D ☐ General Business Credit Carrybacks
- E ☒ Reserved
- F ☒ Reserved
- G ☐ Eligible Small Business Credit Carryforwards
- H ☒ Reserved
- I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III . . . ▶ ☐

	(a) Description of credit Note. On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e	45-3989987	1,307,117
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		1,307,117
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		1,307,117

Form 3800 (2015) Page **3**

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

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B ☐ General Business Credit From a Passive Activity
C ☐ General Business Credit Carryforwards
D ☐ General Business Credit Carrybacks
E ☐ Reserved
F ☐ Reserved
G ☐ Eligible Small Business Credit Carryforwards
H ☐ Reserved

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	(a) Description of credit **Note.** On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e	45-3444400	813,491
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		813,491
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		813,491

Name(s) shown on return: SCANA CORPORATION | Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

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- B ☐ General Business Credit From a Passive Activity
- C ☐ General Business Credit Carryforwards
- D ☒ General Business Credit Carrybacks
- E ☐ Reserved
- F ☐ Reserved
- G ☐ Eligible Small Business Credit Carryforwards
- H ☐ Reserved

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	(a) Description of credit. **Note.** On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		28,145,407
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		2,927
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		28,148,334
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		8,254,946
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		8,254,946
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		36,403,280

ORIGINAL

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2015 or tax year beginning ______________, ending ______________

▶ Information about Form 1120 and its separate instructions is at www.irs.gov/form1120.

OMB No. 1545-0123

2015

A Check if:	TYPE OR PRINT		
1a Consolidated return (attach Form 851) [X]		Name: SCANA CORPORATION	B Employer identification number: 57-0784499
b Life/nonlife consolidated return [ ]		Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY	C Date incorporated: 10/01/1984
2 Personal holding co. (attach Sch. PH) [ ]		City or town, state, or province, country, and ZIP or foreign postal code: CAYCE SC 29033-3701	D Total assets (see instructions): $ 16,789,419,184
3 Personal service corp. (see instructions) [ ]			
4 Schedule M-3 attached [X]			

E Check if: (1) [ ] Initial return (2) [ ] Final return (3) [ ] Name change (4) [ ] Address change

Section	Line	Description	Ref	Amount	Line	Amount
Income	1a	Gross receipts or sales	1a	4,752,235,717		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	4,752,235,717
	2	Cost of goods sold (attach Form 1125-A)			2	2,483,622,176
	3	Gross profit. Subtract line 2 from line 1c			3	2,268,613,541
	4	Dividends (Schedule C, line 19)			4	284,021
	5	Interest			5	4,628,851
	6	Gross rents			6	15,869,608
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	145,167,238
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	320,352,950
	10	Other income (see instructions—attach statement)	See Stmt 1		10	38,753,671
	11	Total income. Add lines 3 through 10 ▶			11	2,793,669,880
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions—attach Form 1125-E) ▶			12	13,893,341
	13	Salaries and wages (less employment credits)			13	82,769,216
	14	Repairs and maintenance			14	257,510,775
	15	Bad debts			15	13,178,603
	16	Rents			16	3,628,032
	17	Taxes and licenses	See Stmt 2		17	262,493,786
	18	Interest			18	142,982,968
	19	Charitable contributions			19	10,485,294
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	628,145,399
	21	Depletion			21	
	22	Advertising			22	12,300,363
	23	Pension, profit-sharing, etc., plans			23	1,437,241
	24	Employee benefit programs			24	58,192,611
	25	Domestic production activities deduction (attach Form 8903)			25	24,496,822
	26	Other deductions (attach statement)	See Stmt 3		26	545,532,198
	27	Total deductions. Add lines 12 through 26 ▶			27	2,057,046,649
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11.			28	736,623,231
	29a	Net operating loss deduction (see instructions)	29a			
	b	Special deductions (Schedule C, line 20)	29b	198,815		
	c	Add lines 29a and 29b			29c	198,815
Tax, Refundable Credits, and Payments	30	Taxable income. Subtract line 29c from line 28 (see instructions)			30	736,424,416
	31	Total tax (Schedule J, Part I, line 11)			31	234,292,607
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	400,220,311
	33	Estimated tax penalty (see instructions). Check if Form 2220 is attached ▶ [X]			33	
	34	Amount owed. If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	NONE
	35	Overpayment. If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	165,927,704
	36	Enter amount from line 35 you want: Credited to 2016 estimated tax ▶ NONE Refunded ▶			36	165,927,704

Sign Here Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer: [signature] Date: 09/13/2016 Title: CONTROLLER

May the IRS discuss this return with the preparer shown below (see instructions)? [X] Yes [ ] No

Paid Preparer Use Only				
Print/Type preparer's name: TERRY R HUGGINS	Preparer's signature: [signature]	Date: 09/13/2016	Check [ ] if self-employed	PTIN: P00969508
Firm's name ▶ ERNST & YOUNG US LLP			Firm's EIN ▶ 34-6565596	
Firm's address ▶ 2 WEST WASHINGTON STREET GREENVILLE SC 29601			Phone no. (864) 242-5740	

SCANA CORPORATION 57-0784499
Form 1120 (2015) Page 3

Schedule J Tax Computation and Payment (see instructions)

Part I–Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)) ▶ ☐				
2	Income tax. Check if a qualified personal service corporation (see instructions) ▶ ☐			2	257,748,546
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	257,748,546
5a	Foreign tax credit (attach Form 1118)	5a	1,691		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	23,454,248		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	Total credits. Add lines 5a through 5e			6	23,455,939
7	Subtract line 6 from line 4			7	234,292,607
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method—completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method—income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions—attach statement)	9f			
10	Total. Add lines 9a through 9f			10	NONE
11	Total tax. Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	234,292,607

Part II–Payments and Refundable Credits

12	2014 overpayment credited to 2015			12	129,997,616
13	2015 estimated tax payments			13	145,000,000
14	2015 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	274,997,616
16	Tax deposited with Form 7004			16	125,000,000
17	Withholding (see instructions)			17	
18	Total payments. Add lines 15, 16, and 17			18	399,997,616
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	222,695		
c	Form 8827, line 8c	19c			
d	Other (attach statement—see instructions)	19d			
20	Total credits. Add lines 19a through 19d			20	222,695
21	Total payments and credits. Add lines 18 and 20. Enter here and on page 1, line 32			21	400,220,311

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

Form **3800**

Department of the Treasury
Internal Revenue Service (99)

General Business Credit

▶ Information about Form 3800 and its separate instructions is at *www.irs.gov/form3800.*
▶ You must attach all pages of Form 3800, pages 1, 2, and 3, to your tax return.

OMB No. 1545-0895
2015
Attachment Sequence No. 22

Name(s) shown on return: SCANA CORPORATION
Identifying number: 57-0784499

Part I Current Year Credit for Credits Not Allowed Against Tentative Minimum Tax (TMT)
(See instructions and complete Part(s) III before Parts I and II)

				Line	Amount
1	General business credit from line 2 of all Parts III with box A checked			1	14,703,607
2	Passive activity credits from line 2 of all Parts III with box B checked	2			
3	Enter the applicable passive activity credits allowed for 2015 (see instructions)			3	0
4	Carryforward of general business credit to 2015. Enter the amount from line 2 of Part III with box C checked. See instructions for statement to attach			4	
5	Carryback of general business credit from 2016. Enter the amount from line 2 of Part III with box D checked (see instructions)			5	
6	Add lines 1, 3, 4, and 5			6	14,703,607

Part II Allowable Credit

				Line	Amount
7	Regular tax before credits: • Individuals. Enter the sum of the amounts from Form 1040, lines 44 and 46, or the sum of the amounts from Form 1040NR, lines 42 and 44 • Corporations. Enter the amount from Form 1120, Schedule J, Part I, line 2; or the applicable line of your return • Estates and trusts. Enter the sum of the amounts from Form 1041, Schedule G, lines 1a and 1b; or the amount from the applicable line of your return			7	257,748,546
8	Alternative minimum tax: • Individuals. Enter the amount from Form 6251, line 35 • Corporations. Enter the amount from Form 4626, line 14 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 56			8	NONE
9	Add lines 7 and 8			9	257,748,546
10a	Foreign tax credit	10a	1,691		
b	Certain allowable credits (see instructions)	10b			
c	Add lines 10a and 10b			10c	1,691
11	Net income tax. Subtract line 10c from line 9. If zero, skip lines 12 through 15 and enter -0- on line 16			11	257,746,855
12	Net regular tax. Subtract line 10c from line 7. If zero or less, enter -0-	12	257,746,855		
13	Enter 25% (.25) of the excess, if any, of line 12 over $25,000 (see instructions)	13	64,430,464		
14	Tentative minimum tax: • Individuals. Enter the amount from Form 6251, line 33 • Corporations. Enter the amount from Form 4626, line 12 • Estates and trusts. Enter the amount from Schedule I (Form 1041), line 54	14	147,802,811		
15	Enter the greater of line 13 or line 14			15	147,802,811
16	Subtract line 15 from line 11. If zero or less, enter -0-			16	109,944,044
17	Enter the smaller of line 6 or line 16 C corporations: See the line 17 instructions if there has been an ownership change, acquisition, or reorganization.			17	14,703,607

SCANA CORPORATION 57-0784499
Form 3800 (2015) Page 2

Part II **Allowable Credit** *(Continued)*

Note. If you are not required to report any amounts on lines 22 or 24 below, skip lines 18 through 25 and enter -0- on line 26.

Line	Description		Amount
18	Multiply line 14 by 75% (.75) (see instructions)	18	
19	Enter the greater of line 13 or line 18	19	
20	Subtract line 19 from line 11. If zero or less, enter -0-	20	0
21	Subtract line 17 from line 20. If zero or less, enter -0-	21	0
22	Combine the amounts from line 3 of all Parts III with box A, C, or D checked	22	0
23	Passive activity credit from line 3 of all Parts III with box B checked — 23: 0		
24	Enter the applicable passive activity credit allowed for 2015 (see instructions)	24	0
25	Add lines 22 and 24	25	0
26	Empowerment zone and renewal community employment credit allowed. Enter the smaller of line 21 or line 25	26	0
27	Subtract line 13 from line 11. If zero or less, enter -0-	27	193,316,391
28	Add lines 17 and 26	28	14,703,607
29	Subtract line 28 from line 27. If zero or less, enter -0-	29	178,612,784
30	Enter the general business credit from line 5 of all Parts III with box A checked	30	8,750,641
31	Reserved	31	
32	Passive activity credits from line 5 of all Parts III with box B checked — 32: 0		
33	Enter the applicable passive activity credits allowed for 2015 (see instructions)	33	0
34	Carryforward of business credit to 2015. Enter the amount from line 5 of Part III with box C checked and line 6 of Part III with box G checked. See instructions for statement to attach	34	0
35	Carryback of business credit from 2016. Enter the amount from line 5 of Part III with box D checked (see instructions)	35	0
36	Add lines 30, 33, 34, and 35	36	8,750,641
37	Enter the smaller of line 29 or line 36	37	8,750,641
38	**Credit allowed for the current year.** Add lines 28 and 37. Report the amount from line 38 (if smaller than the sum of Part I, line 6, and Part II, lines 25 and 36, see instructions) as indicated below or on the applicable line of your return: • Individuals. Form 1040, line 54, or Form 1040NR, line 51 • Corporations. Form 1120, Schedule J, Part I, line 5c • Estates and trusts. Form 1041, Schedule G, line 2b	38	23,454,248

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

- A ☐ General Business Credit From a Non-Passive Activity
- B ☐ General Business Credit From a Passive Activity
- C ☐ General Business Credit Carryforwards
- D ☐ General Business Credit Carrybacks
- E ☒ Reserved
- F ☒ Reserved
- G ☐ Eligible Small Business Credit Carryforwards
- H ☒ Reserved

I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III . . . ▶ ☒

	(a) Description of credit **Note.** On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		14,581,384
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		122,223
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		14,703,607
3	Enter the amount from Form 8844 here and on the applicable line of Part II.	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		8,750,641
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II.	5		8,750,641
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II.	6		23,454,248

Form 3800 (2015) Page 3

Name(s) shown on return	Identifying number
SCANA CORPORATION	57-0784499

Part III **General Business Credits or Eligible Small Business Credits** (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

A ☒ General Business Credit From a Non-Passive Activity
B ☐ General Business Credit From a Passive Activity
C ☐ General Business Credit Carryforwards
D ☐ General Business Credit Carrybacks
E ☒ Reserved
F ☒ Reserved
G ☐ Eligible Small Business Credit Carryforwards
H ☒ Reserved

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	(a) Description of credit Note. On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		14,581,384
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		122,223
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		14,703,607
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e		
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		14,703,607

Form 3800 (2015) Page 3

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

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- B [ ] General Business Credit From a Passive Activity
- C [ ] General Business Credit Carryforwards
- D [ ] General Business Credit Carrybacks
- E [x] Reserved
- F [x] Reserved
- G [ ] Eligible Small Business Credit Carryforwards
- H [x] Reserved
- I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III . . . ▶ [ ]

	(a) Description of credit Note. On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e	27-1302931	6,630,033
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		6,630,033
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		6,630,033

Form 3800 (2015) Page 3

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

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B ☐ General Business Credit From a Passive Activity
C ☐ General Business Credit Carryforwards
D ☐ General Business Credit Carrybacks
E ☒ Reserved
F ☐ Reserved
G ☐ Eligible Small Business Credit Carryforwards
H ☒ Reserved

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1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e	45-3989987	1,307,117
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		1,307,117
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		1,307,117

Form 3800 (2015) Page 3

Name(s) shown on return: SCANA CORPORATION

Identifying number: 57-0784499

Part III General Business Credits or Eligible Small Business Credits (see instructions)

Complete a separate Part III for each box checked below. (see instructions)

A [X] General Business Credit From a Non-Passive Activity
B [ ] General Business Credit From a Passive Activity
C [ ] General Business Credit Carryforwards
D [ ] General Business Credit Carrybacks
E [X] Reserved
F [X] Reserved
G [ ] Eligible Small Business Credit Carryforwards
H [X] Reserved

I If you are filing more than one Part III with box A or B checked, complete and attach first an additional Part III combining amounts from all Parts III with box A or B checked. Check here if this is the consolidated Part III . . . ▶ [ ]

	(a) Description of credit Note. On any line where the credit is from more than one source, a separate Part III is needed for each pass-through entity.		(b) If claiming the credit from a pass-through entity, enter the EIN	(c) Enter the appropriate amount
1a	Investment (Form 3468, Part II only) (attach Form 3468)	1a		
b	Reserved	1b		
c	Increasing research activities (Form 6765)	1c		
d	Low-income housing (Form 8586, Part I only)	1d		
e	Disabled access (Form 8826) (see instructions for limitation)	1e		
f	Renewable electricity, refined coal, and Indian coal production (Form 8835)	1f		
g	Indian employment (Form 8845)	1g		
h	Orphan drug (Form 8820)	1h		
i	New markets (Form 8874)	1i		
j	Small employer pension plan startup costs (Form 8881) (see instructions for limitation)	1j		
k	Employer-provided child care facilities and services (Form 8882) (see instructions for limitation)	1k		
l	Biodiesel and renewable diesel fuels (attach Form 8864)	1l		
m	Low sulfur diesel fuel production (Form 8896)	1m		
n	Distilled spirits (Form 8906)	1n		
o	Nonconventional source fuel	1o		
p	Energy efficient home (Form 8908)	1p		
q	Energy efficient appliance	1q		
r	Alternative motor vehicle (Form 8910)	1r		
s	Alternative fuel vehicle refueling property (Form 8911)	1s		
t	Reserved	1t		
u	Mine rescue team training (Form 8923)	1u		
v	Agricultural chemicals security (carryforward only)	1v		
w	Employer differential wage payments (Form 8932)	1w		
x	Carbon dioxide sequestration (Form 8933)	1x		
y	Qualified plug-in electric drive motor vehicle (Form 8936)	1y		
z	Qualified plug-in electric vehicle (carryforward only)	1z		
aa	New hire retention (carryforward only)	1aa		
bb	General credits from an electing large partnership (Schedule K-1 (Form 1065-B))	1bb		
zz	Other	1zz		
2	Add lines 1a through 1zz and enter here and on the applicable line of Part I	2		
3	Enter the amount from Form 8844 here and on the applicable line of Part II	3		
4a	Investment (Form 3468, Part III) (attach Form 3468)	4a		
b	Work opportunity (Form 5884)	4b		
c	Biofuel producer (Form 6478)	4c		
d	Low-income housing (Form 8586, Part II)	4d		
e	Renewable electricity, refined coal, and Indian coal production (Form 8835)	4e	45-3444400	813,491
f	Employer social security and Medicare taxes paid on certain employee tips (Form 8846)	4f		
g	Qualified railroad track maintenance (Form 8900)	4g		
h	Small employer health insurance premiums (Form 8941)	4h		
i	Reserved	4i		
j	Reserved	4j		
z	Other	4z		
5	Add lines 4a through 4z and enter here and on the applicable line of Part II	5		813,491
6	Add lines 2, 3, and 5 and enter here and on the applicable line of Part II	6		813,491

FORMS (TAX)

FORM NUMBER

GA 600

JURISDICTION

GEORGIA

MONTH	YEAR
	2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

PLEASE DO NOT MAIL!

ERO MUST RETAIN THIS FORM.
DO NOT SUBMIT THIS FORM TO
GEORGIA DEPARTMENT OF REVENUE
UNLESS REQUESTED TO DO SO.

IRS DCN OR SUBMISSION ID

**GA-8453C
2016**

GEORGIA CORPORATE INCOME TAX DECLARATION FOR ELECTRONIC FILING SUMMARY OF AGREEMENT BETWEEN TAXPAYER AND ERO OR PAID PREPARER

☐ GA Consolidated Subsidiary
☐ Consolidated Parent FEIN
☐ Address Change
☐ Name Change
☐ Final

2016 Income Tax Return	**2017** Net Worth Return
Beginning 01/01/2016	Beginning 01/01/2017
Ending 12/31/2016	Ending 12/31/2017

☐ Consolidated GA Parent
[X] Original Return
☐ Amended Return
☐ IT-552
☐ Initial Net Worth
[X] Extension
☐ PL 86-272

Federal Employer ID Number	Name (Corporate title)			Date admitted into GA
57-0248695	SOUTH CAROLINA ELECTRIC AND GAS COMPANY			08/24/1950
Location of Books (City & State)	Business Address			Incorporated under laws of what state
CAYCE, SC	220 OPERATION WAY			SC
Telephone Number	City or Town	State	Zip Code	NAICS Code
803-217-9000	CAYCE	SC	29033	221100

PART I **TAX RETURN INFORMATION**

1. Federal taxable income (Form 600, Sch 1, Line 1)		1.	20279948
2. Georgia taxable income (Form 600, Sch 1, Line 7)		2.	NONE
3. Net Worth (Form 600, Sch 2, Line 4)		3.	5338576131
4. Net Worth Taxable by Georgia (Form 600, Sch 2, Line 6)		4.	2840123
5. Tax Amounts (Form 600, Sch 3, Line 1) . . . . . . Income ▶	NONE	. . . . Net Worth ▶	1000
6. Balance of Tax due with return (Form 600, Sch 3, Line 10)		6.	
7. Refund (Form 600, Sch 3, Line 11) . . . Credited to 2017 ▶	45821	. . . . Refunded ▶	

PART II **DECLARATION OF CORPORATE OFFICER**

Under penalties of perjury, I declare that the information I have provided to the corporation's Electronic Return Originator (ERO) and/or Online Service Provider and/or Transmitter and the amounts shown in Part I agree with the amounts shown on the corresponding lines of the electronic portion of the corporation's 2016 Georgia Corporate Income Tax Return. I declare that I have examined the corporation's tax return, including accompanying schedules and statements, and to the best of my knowledge and belief, the corporation's return is true, correct and complete. I consent that the electronic portion of the corporation's return may be sent by my ERO/Online Service Provider/Transmitter.

SIGN HERE ▶ SIGNATURE OF OFFICER — DATE 10/11/2017 — TITLE CONTROLLER

PRINT NAME JAMES E SWAN IV — EMAIL

PART III **DECLARATION OF ELECTRONIC RETURNS ORIGINATOR AND PAID PREPARER**

I DECLARE THAT I HAVE REVIEWED THE ABOVE CORPORATION'S RETURN AND THAT THE ENTRIES ON THE GA-8453C ARE COMPLETE AND CORRECT TO THE BEST OF MY KNOWLEDGE.

ERO's Use Only
ERO's Signature ____ Date ____
Firm's Name ____ Check if also paid preparer [X]
Address ____
City, State & Zip Code ____

IF PREPARED BY A PERSON OTHER THAN THE TAXPAYER, THIS DECLARATION IS BASED ON ALL THE INFORMATION OF WHICH THE TAXPAYER HAS ANY KNOWLEDGE.

Paid Preparer's Use Only
Paid Preparer's Signature ____ Date ____
Firm's Name ____ FEIN/PTIN ____
Address ____ SSN/TIN ____
City, State & Zip Code ____

1062

GA-8453C (REV. 09/23/16) **KEEP A COPY WITH YOUR RECORDS**

1701401417

Georgia Form 600 (Rev. 07/26/16)
Corporation Tax Return
Georgia Department of Revenue (Approved software version)

2016 Income Tax Return

Page 1

Beginning 01/01/2016
Ending 12/31/2016

2017 Net Worth Tax Return
Beginning 01/01/2017
Ending 12/31/2017

[X] Original Return
[ ] Initial Net Worth
[ ] Amended Return
[ ] Amended due to IRS Audit
[ ] Consolidated GA Parent Return (attach approval)
[ ] GA Consolidated Subsidiary
Consolidated Parent FEIN ______
[ ] Address Change
[ ] Name Change
[ ] Final (attach explanation)
[ ] PL 86-272
[ ] UET Annualization Exception attached
[ ] IT-552 attached
[X] Extension attached

A. Federal Employer I.D. Number: 57-0248695
B. Name (Corporate title) Please give former name if applicable.: SOUTH CAROLINA ELECTRIC AND GAS COM
C. GA Withholding Tax Account Number: 80-8507984
D. Business Address (Number and Street): 220 OPERATION WAY
E. GA Sales Tax Registration Number: 036-87-01894
F. City or Town: CAYCE
G. State: SC
H. Zip Code: 29033
I. Foreign Country Name:
J. NAICS Code: 221100
K. Date of Incorporation: 07/19/1924
L. Incorporated under laws of what state: SC
M. Date admitted into GA: 08/24/1950
N. Location of Books for Audit (City) & (State): CAYCE SC
O. Telephone Number: 803-217-9000
P. Kind of Business: UTILITY

Q. Indicate latest taxable year adjusted by IRS ► ______ R. And when reported to Georgia ► ______

COMPUTATION OF GEORGIA TAXABLE INCOME AND TAX (ROUND TO NEAREST DOLLAR)		SCHEDULE 1
1. Federal Taxable Income (Copy of Federal return and supporting schedules must be attached)	1.	20279948
2. Additions to Federal Income (from Schedule 4)	2.	480130606
3. Total (add Lines 1 and 2)	3.	500410554
4. Subtractions from Federal Income (from Schedule 5)	4.	372278973
5. Balance (Line 3 less Line 4)	5.	128131581
6. Georgia Net Operating loss deduction (from Schedule 11)	6.	
7. Georgia Taxable Income (Line 5 less Line 6 or Schedule 7, Line 9)	7.	NONE
8. Income Tax - (6% x Line 7)	8.	NONE

COMPUTATION OF NET WORTH TAX (ROUND TO NEAREST DOLLAR)		SCHEDULE 2
1. Total Capital stock issued	1.	576505122
2. Paid in or Capital surplus	2.	2283832337
3. Total Retained earnings	3.	2478238672
4. Net Worth (Total of Lines 1, 2, and 3)	4.	5338576131
5. Ratio (GA. and Dom. For. Corp.-100%) (Foreign Corp. - Line 4, Sch. 8) 5. 0.000532		
6. Net Worth Taxable by Georgia (Line 4 x Line 5)	6.	2840123
7. Net Worth Tax (from table in instructions)	7.	1000

Form **7004** (Rev. December 2016) Department of the Treasury Internal Revenue Service

Application for Automatic Extension of Time To File Certain Business Income Tax, Information, and Other Returns

▶ File a separate application for each return.
▶ Information about Form 7004 and its separate instructions is at www.irs.gov/form7004.

OMB No. 1545-0233

Print or Type	
Name: SCANA CORPORATION	Identifying number: 57-0784499
Number, street, and room or suite no. (If P.O. box, see instructions.): 220 OPERATION WAY	
City, town, state, and ZIP code (If a foreign address, enter city, province or state, and country (follow the country's practice for entering postal code)).: CAYCE, SC 29033-3701	

Note: File request for extension by the due date of the return for which the extension is granted. See instructions before completing this form.

Part I Automatic Extension for C Corporations With Tax Years Ending December 31. See instructions.

1a Enter the form code for the return listed below that this application is for 1 2

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part II Automatic Extension for Certain Estates and Trusts. See instructions.

b Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1041 (estate other than a bankruptcy estate)	04	Form 1041 (trust)	05

Part III Automatic Extension for Entities Not Using Part I, II, or IV. See instructions.

c Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 706-GS(D)	01	Form 1120-ND (section 4951 taxes)	20
Form 706-GS(T)	02	Form 1120-PC	21
Form 1041 (bankruptcy estate only)	03	Form 1120-POL	22
Form 1041-N	06	Form 1120-REIT	23
Form 1041-QFT	07	Form 1120-RIC	24
Form 1042	08	Form 1120S	25
Form 1065	09	Form 1120-SF	26
Form 1065-B	10	Form 3520-A	27
Form 1066	11	Form 8612	28
Form 1120	12	Form 8613	29
Form 1120-C	34	Form 8725	30
Form 1120-F	15	Form 8804	31
Form 1120-FSC	16	Form 8831	32
Form 1120-H	17	Form 8876	33
Form 1120-L	18	Form 8924	35
Form 1120-ND	19	Form 8928	36

Part IV Automatic Extension for C Corporations With Tax Years Ending June 30. See instructions.

d Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part V All Filers Must Complete This Part

2	If the organization is a foreign corporation that does not have an office or place of business in the United States, check here . . . ▶		☐
3	If the organization is a corporation and is the common parent of a group that intends to file a consolidated return, check here . . . ▶ If checked, attach a statement listing the name, address, and Employer Identification Number (EIN) for each member covered by this application.		☒
4	If the organization is a corporation or partnership that qualifies under Regulations section 1.6081-5, check here . . ▶		☐
5a	The application is for calendar year 20 16 , or tax year beginning ________, 20 ___, and ending ________, 20 ___		
b	Short tax year. If this tax year is less than 12 months, check the reason: ☐ Initial return ☐ Final return ☐ Change in accounting period ☐ Consolidated return to be filed ☐ Other (see instructions - attach explanation)		
6	Tentative total tax . . .	6	6,000,000.
7	Total payments and credits (see instructions) . . .	7	6,000,000.
8	Balance due. Subtract line 7 from line 6 (see instructions) . . .	8	

Form 7004 - Affiliated Group Members

Name	Employer ID	Name	Employer ID
SCANA SERVICES INC	57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695
SOUTH CAROLINA FUEL CO INC	57-0691209	SC GENERATING COMPANY INC	57-0784498
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908	SCANA ENERGY MARKETING INC	57-0850977
SERVICECARE INC	57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	56-2128483
CLEAN ENERGY ENTERPRISES INC	56-1078443	PSNC BLUE RIDGE CORPORATION	56-1791764
PSNC CARDINAL PIPELINE COMPANY	56-1955423	SCANA CORPORATE SECURITY SERVICES INC	20-0989017

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(Corporation) Name SOUTH CAROLINA ELECTRIC AND GAS COM FEIN 57-0248695

COMPUTATION OF TAX DUE OR OVERPAYMENT (ROUND TO NEAREST DOLLAR)	A. Income Tax	B. Net Worth Tax		C. Total
1. Total Tax (Schedule 1, Line 8, and Schedule 2, Line 7)	NONE	1000	1.	1000
2. Credits and payments of estimated tax			2.	46821
3. Credits used from Schedule 9*			3.	
4. Withholding Credits (G2-A, G2-LP, and/or G2-RP)			4.	
5. Balance of tax due (Line 1, less Lines 2, 3, and 4)			5.	
6. Amount of overpayment (Lines 2, 3, and 4 less Line 1)			6.	45821
7. Interest due (See Instructions)			7.	
8. Form 600 UET (Estimated tax penalty)			8.	
9. Other penalty due (See Instructions)			9.	
10. Balance of tax, interest and penalty due with return			10.	
11. Amount of Line 6 less Line 8 to be credited to 2017 estimated tax ▶		45821 Refunded	11.	

SCHEDULE 3

*NOTE: Any tax credits from Schedule 9 may be applied against income tax liability only, not net worth tax liability.

SEE PAGE 3 SIGNATURE SECTION FOR DIRECT DEPOSIT OPTIONS

ADDITIONS TO FEDERAL TAXABLE INCOME (ROUND TO NEAREST DOLLAR)		SCHEDULE 4
1. State and municipal bond interest (other than Georgia or political subdivision thereof)	1.	
2. Net income or net profits taxes imposed by taxing jurisdictions other than Georgia	2.	
3. Expense attributable to tax exempt income	3.	
4. Net operating loss deducted on Federal return	4.	
5. Federal deduction for income attributable to domestic production activities (IRC Section 199)	5.	
6. Intangible expenses and related interest cost	6.	6296983
7. Captive REIT expenses and costs	7.	
8. Other Additions (Attach Schedule) See Statement 1	8.	473833623
9. TOTAL - Enter also on LINE 2, SCHEDULE 1	9.	480130606

SUBTRACTIONS FROM FEDERAL TAXABLE INCOME (ROUND TO NEAREST DOLLAR)		SCHEDULE 5
1. Interest on obligations of United States (must be reduced by direct and indirect interest expense).	1.	
2. Exception to intangible expenses and related interest cost (Attach IT-Addback)	2.	6296983
3. Exception to captive REIT expenses and costs (Attach IT-REIT)	3.	
4. Other Subtractions (Must Attach Schedule) See Statement 1	4.	365981990
5. TOTAL - Enter also on LINE 4, SCHEDULE 1	5.	372278973

APPORTIONMENT OF INCOME	A. WITHIN GEORGIA	B. EVERYWHERE	C. DO NOT ROUND COL (A)/ COL (B) COMPUTE TO SIX DECIMALS
1. Gross receipts from business 1.	NONE	3015062430	
2. Georgia Ratio (Divide Column A by Column B) 2.			NONE

SCHEDULE 6

COMPUTATION OF GEORGIA NET INCOME (ROUND TO NEAREST DOLLAR)		SCHEDULE 7
1. Net business income (Schedule 1, Line 5)	1.	128131581
2. Income allocated everywhere (Must Attach Schedule)	2.	
3. Business income subject to apportionment (Line 1 less Line 2)	3.	128131581
4. Georgia Ratio (Schedule 6, Column C) 4. NONE		
5. Net business income apportioned to Georgia (Line 3 x Line 4)	5.	NONE
6. Net income allocated to Georgia (Attach Schedule)	6.	
7. Total of Lines 5 and 6	7.	NONE
8. Less: net operating loss apportioned to GA (from Schedule 11)	8.	
9. Georgia taxable income (Enter also on Schedule 1, Line 7)	9.	NONE

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(Corporation) Name SOUTH CAROLINA ELECTRIC AND GAS COM FEIN 57-0248695

COMPUTATION OF GEORGIA NET WORTH RATIO (TO BE USED BY FOREIGN CORPS ONLY) **SCHEDULE 8**

		A. WITHIN GEORGIA	B. TOTAL EVERYWHERE	C. GA Ratio (A/B) DO NOT ROUND COMPUTE TO SIX DECIMALS
1.	Total value of property owned (Total assets from Federal balance sheet) 1.	9593164	15019055753	
2.	Gross receipts from business . . . 2.	NONE	3015062430	
3.	Totals (Line 1 plus Line 2) . . . 3.	9593164	18034118183	
4.	Georgia Ratio (Divide Line 3A by 3B) . . . 4.			0.000532

A Copy of the Federal Return and supporting Schedules must be attached, otherwise this return shall be deemed incomplete.
No extension of time for filing will be allowed unless a copy of the request for a Federal extension or Form IT-303 is attached to this return.

Make check payable to: Georgia Department of Revenue
Mail to: Georgia Department of Revenue, Processing Center, PO Box 740397, Atlanta, Georgia 30374-0397

DIRECT DEPOSIT OPTIONS

A. Direct Deposit (For U.S. Accounts Only) See booklet for further instructions. **If Direct Deposit is not selected, a paper check will be issued.**

Type: Checking ☐ **Savings** ☐ **Routing Number**

Account Number

Declaration: I/We declare under the penalties of perjury that I/we have examined this return (including accompanying schedules and statements) and to the best of my/our knowledge and belief, it is true, correct, and complete. If prepared by a person other than the taxpayer, this declaration is based on all information of which the preparer has knowledge. Georgia Public Revenue Code Section 48-2-31 stipulates that taxes shall be paid in lawful money of the United States, free of any expense to the State of Georgia.

☐ I authorize the Georgia Department of Revenue to electronically notify me at the below email address regarding any updates to my account(s).

Email Address: ______________________

☐ Check the box to authorize the Georgia Department of Revenue to discuss the contents of this tax return with the named preparer.

SIGNATURE OF OFFICER

SIGNATURE OF INDIVIDUAL OR FIRM PREPARING THE RETURN

CONTROLLER

TITLE

FIRM PREPARING THE RETURN

10/11/2017

DATE

IDENTIFICATION OR SOCIAL SECURITY NUMBER

6D1214 1.000

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1701401447

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(Corporation) Name SOUTH CAROLINA ELECTRIC AND GAS COM FEIN 57-0248695

CREDIT USAGE AND CARRYOVER (ROUND TO NEAREST DOLLAR) **SCHEDULE 9**

1. **Complete a separate schedule for each Credit Code.**
2. Total the amounts on Line 13 of each schedule and enter the total on the credit line of the return.
3. If there is a credit eligible for carryover to 2016, please complete a schedule even if the credit is not used in 2016.
4. See the tax booklet for a list of credit codes.
5. See the relevant forms, statutes, and regulations to determine how the credit is allocated to the owners, to determine when carryovers expire, and to see if the credit is limited to a certain percentage of tax.
6. If the credit for a particular credit code originated with more than one person or company, enter separate information on Lines 3 through 9 below.
7. The credit certificate number is issued by the Department of Revenue for credits that are preapproved. If applicable, please enter the Department of Revenue credit certificate number where indicated.
8. Before the Line 14 carryover is applied to the next year, the amount must be reduced by any amounts elected to be applied to withholding in 2016 and by any carryovers that have expired.

For the credit generated this year, list the Company Name, ID number, Credit Certificate number, if applicable, and % of credit (purchased credits and credits received from an assignment should also be included). If the credit originated with this taxpayer, enter this taxpayer's name and ID# below and 100% for the percentage.

1. Credit Type Code
2. Credit remaining from previous years (do not include amounts elected to be applied to withholding)
3. Company Name | ID Number

Credit Certificate # | % of Credit | Credit Generated in 2016

4. Company Name | ID Number

Credit Certificate # | % of Credit | Credit Generated in 2016

5. Company Name | ID Number

Credit Certificate # | % of Credit | Credit Generated in 2016

6. Company Name | ID Number

Credit Certificate # | % of Credit | Credit Generated in 2016

7. Company Name | ID Number

Credit Certificate # | % of Credit | Credit Generated in 2016

8. Company Name | ID Number

Credit Certificate # | % of Credit | Credit Generated in 2016

9. Company Name | ID Number

Credit Certificate # | % of Credit | Credit Generated in 2016

10. Total available credit for 2016 (sum of Lines 2 through 9) 10.
11. Enter the amount assigned to affiliated entities (See Schedule 10) 11.
12. Enter the amount of the credit sold (Conservation and Film Tax Credits) 12.
13. Credit Used in 2016 13.
14. Potential carryover to 2017 (Line 10 less Lines 11,12, and 13) 14.

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(Corporation) Name SOUTH CAROLINA ELECTRIC AND GAS COM FEIN 57-0248695

ASSIGNED TAX CREDITS (ROUND TO NEAREST DOLLAR) **SCHEDULE 10**

Georgia Code Section 48-7-42 provides that in lieu of claiming any Georgia income tax credit for which a taxpayer otherwise is eligible for the taxable year, the taxpayer may elect to assign credits in whole or in part to one or more "affiliated entities". The term "affiliated entities" is defined as:

1) A corporation that is a member of the taxpayer's affiliated group within the meaning of Section 1504(a) of the Internal Revenue Code; or
2) An entity affiliated with a corporation, business, partnership, or limited liability company taxpayer, which entity:
   (a) Owns or leases the land on which a project is constructed;
   (b) Provides capital for construction of the project; and
   (c) Is the grantor or owner under a management agreement with a managing company for the project.

No carryover attributable to the unused portion of any previously claimed or assigned credit may be assigned or reassigned, except if the assignor and the recipient of an assigned tax credit cease to be affiliated entities, then any carryover attributable to the unused portion of the credit is transferred back to the assignor of the credit. The assignor is permitted to use any such carryover and also shall be permitted to assign the carryover to one or more affiliated entities, as if such carryover were an income tax credit for which the assignor became eligible in the taxable year in which the carryover was transferred back to the assignor. In the case of any credit that must be claimed in installments in more than one taxable year, the election under this subsection may be made on an annual basis with respect to each such installment. For additional information, please refer to Georgia Code Section 48-7-42.

If the corporation filing this return is assigning tax credits to other affiliates, please provide detail below specifying where the tax credits are being assigned.

All assignments of credits must be made before the statutory due date (including extensions) per O.C.G.A. § 48-7-42 (b).

	Credit Code	Corporation Name	FEIN		Amount of Credit	Credit Certificate # (if applicable)
1.				1.		
2.				2.		
3.				3.		
4.				4.		
5.				5.		
6.				6.		
7.				7.		
8.				8.		

6D1246 1.000

Georgia Form **600/2016**

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(Corporation) Name SOUTH CAROLINA ELECTRIC AND GAS COM FEIN 57-0248695

GA NOL Carry Forward Worksheet (ROUND TO NEAREST DOLLAR) **SCHEDULE 11**

For calendar year or fiscal year beginning 01/01/2016 **and ending** 01/01/2016

	A Loss Year	B Loss Amount	C Income Year	D NOL Utilized	E Balance	F Remaining NOL
1.						
2.						
3.						
4.						
5.						
6.						
7.						
8.						
9.						
10.						
11.						
12.						
13.						
14.						
15.						
16.						
17.						
18.						
19.						
20.						

1. NOL Carry Forward Available to Current Year (Enter on Schedule 1, Line 6 or Schedule 7, Line 8)
2. Current Year Income / (Loss)
3. NOL Carry Forward Available to Next Year (Subtract Line 2 from Line 1)

INSTRUCTIONS

Column A: List the loss year(s).

Column B: List the loss amount for the tax year listed in Column A.

Columns C & D: List the years in which the losses were utilized and the amount utilized each year.

Column E: List the balance of the NOL after each year has been applied.

Column F: List the remaining NOL applicable to each loss year.

Total the remaining NOL (Col. F) and enter in the space at the bottom of the worksheet for "NOL Carry Forward Available to Current Year". Then insert "Current Year Income / (Loss)" in the space provided and compute the "NOL Carry Forward Available to Next Year" in the last space. **DO NOT check the box for IT-552 on the return if Schedule 11 is used.** Create photocopies as needed. See example worksheet in 611 instructions.

STATE OF GEORGIA

Department of Revenue
Related Member Intangible Expenses and Costs and Interest Expenses and Costs

IT-Addback (12/08)

A. Taxpayer Information

SOUTH CAROLINA ELECTRIC AND GAS CO	220 OPERATION WAY CAYCE SC 29033
Taxpayer Name	Taxpayer Address
57-0248695	01/01/2016 TO 12/31/2016
Federal Identification Number	Taxable Year (Beginning & End)

Note: Regulation 560-7-3-.05(2) requires that the taxpayer add back related member costs to income *prior* to claiming any exception to the addback.

B. Addback

1. Related member intangible expenses and costs, and interest expenses and costs required to be added back pursuant to Code § 48-7-28.3 and Regulation 560-7-3-.05. Enter amount here and on the applicable line of the tax return in the Georgia "additions to federal taxable income" section. — 1. 6,296,983.

C. Exception for Income Allocated or Apportioned to and Taxed by Georgia or Another State. (For additional information, please see subsection (d) of Code § 48-7-28.3 and paragraph (5) of Regulation 560-7-3-.05).

Attach a separate schedule for each related member. See Statement 2

1. Name of the related member. — 1. SCANA CORPORATION
2. Federal Identification Number of the related member. — 2. 57-0784489
3. Amount of the related member costs taxpayer paid directly or indirectly to such related member. — 3. 5,986,021.
4. Name of each state to whom net income tax was paid by the related member on a tax base which included the related member costs. Do not include jurisdictions in which the related member costs are subject to elimination.

a	b	c	d
S. CAROLINA			

(Attach a schedule if there are more than four states with respect to questions 4 through 9).

5. Enter type of tax paid in each state by the related member.

a	b	c	d
INCOME			

6. Amount of the related member costs paid by the taxpayer and reported by the related member as income subject to allocation and/or apportionment in each respective state.

a	b	c	d
5,986,021.			

7. Apportionment ratio (to six decimals) in each respective state applicable to the amount in line 6. If the related member cost reported to a respective state was allocated in full to that state, enter "1" for that state.

a	b	c	d
1.000000			

8. Multiply the amounts in line 6 by the factors in the corresponding boxes of line 7 and enter the result in the corresponding boxes below.

a	b	c	d
5,986,021.			

9. Total amount eligible for this exception. Add lines 8a through 8d. 9. 5,986,021.

Please see examples in Regulation 560-7-3-.05(5) for further guidance on the above calculations.

10. Provide a brief description of the arm's length status of the transactions between the taxpayer and the related member. Please see subparagraph (5)(d)5. of Regulation 560-7-3-.05 for specific information that should be included:

THE PARTIES ESTABLISHED A MONEY POOL TO COORDINATE AND PROVIDE FOR CERTAIN OF THEIR SHORT-TERM CASH AND WORKING CAPITAL REQUIREMENTS. INTEREST IS CHARGED DAILY BASED ON HIGH GRADE UNSECURED 30 DAY COMMERCIAL PAPER AS QUOTED IN THE WSJ.

D. **Exception for Expenses Paid, Accrued, or Incurred to a Related Member Domiciled in a Foreign Nation.** (For additional information, please see subsection (e) of Code § 48-7-28.3 and paragraph (6) of Regulation 560-7-3-.05).

Attach a separate schedule for each related member.

1. Name of the related member. 1. ________

2. Federal Identification Number of the related member. 2. ________

3. Country of domicile of the related member. 3. ________

4. Provide a description of the comprehensive income tax treaty:

5. Provide a description of the business purpose of the transactions between the taxpayer and the related member. Please see subparagraph (6)(b)5. of Regulation 560-7-3-.05 for the specific information that should be included:

6. Provide a brief description of the arm's length status of the transactions between the taxpayer and the related member. Please see subparagraph (5)(d)5. of Regulation 560-7-3-.05 for specific information that should be included:

7. Amount of the related member costs paid to such related member. (Amount eligible for this exception). 7. ________

E. Exception for Expenses Paid, Accrued, or Incurred to a Related Member Who Paid, Accrued, or Incurred Expenses to a Person Who is Not a Related Member. (For additional information, please see subsection (f) of Code §48-7-28.3 and paragraph (7) of Regulation 560-7-3-.05).

Attach a separate schedule for each related member.

1. Name of the related member. 1.

2. Federal Identification Number of the related member. 2.

3. Name of the unrelated party to whom the costs were paid. 3.

4. Federal Identification Number of such unrelated party. 4.

5. Provide a description of the business purpose of the transactions between the taxpayer and the related member. Please see subparagraph (7)(b)2. of Regulation 560-7-3-.05 for the specific information that should be included:

6. Provide a description of the business purpose of the transactions between the related member and the unrelated party. Please see subparagraph (7)(b)2. of Regulation 560-7-3-.05 for the specific information that should be included:

7. Portion of the related member costs paid by such related member to the unrelated party. (Amount eligible for this exception). 7.

F. Total Amount Eligible for Exception:

Add Line 9 of Section C, Line 7 of Section D, and Line 7 of Section E. Include the amounts from the same lines of any separate schedules attached. Enter the total amount here and on the applicable line of the tax return in the Georgia subtractions from income section. The sum total of all exceptions reported on the tax return pursuant to Form IT-Addback, including any additional schedules, cannot be greater than the amount on Line 1 of Section B. 6,296,983.

1713501414

Form **4562** (Rev. 07/12/16) **GEORGIA**

Georgia Depreciation and Amortization

(Including Information on Listed Property)

Note: Georgia does not allow any additional depreciation benefits provided by I.R.C. Section 168(k), 1400L, 1400N(d)(1), and certain other provisions.

▶ See separate instructions. ▶ Attach to your return.

2016

Names(s) shown on return	Business or activity to which this form relates	Identification number
SOUTH CAROLINA ELECTRIC AND GAS	General Depreciation & Amortiz	57-0248695

Part I **Election To Expense Certain Tangible Property Under Section 179**
Note: *If you have any listed property, complete Part V before you complete Part I.*

1	Maximum amount. See IRS instructions for a higher limit for certain businesses	1	$500,000
2	Total cost of IRC Section 179 property placed in service (see IRS instructions)	2	
3	Threshold cost of IRC Section 179 property before reduction in limitation	3	$2,010,000
4	Reduction in limitation. Subtract line 3 from line 2. If zero or less, enter -0-	4	
5	Dollar limitation for tax year. Subtract line 4 from line 1. If zero or less, enter -0-. If married filing separately, see IRS instructions	5	

	(a) Description of property	(b) Cost (business use only)	(c) Elected cost
6			
7	Listed property. Enter the amount from line 29	7	

8	Total elected cost of IRC Section 179 property. Add amounts in column (c), lines 6 and 7	8	
9	Tentative deduction. Enter the smaller of line 5 or line 8	9	
10	Carryover of disallowed deduction from line 13 of your 2015 Form 4562	10	
11	Business income limitation. Enter the smaller of business income (not less than zero) or line 5	11	
12	IRC Section 179 expense deduction. Add lines 9 and 10, but do not enter more than line 11	12	
13	Carryover of disallowed deduction to 2017. Add lines 9 and 10, less line 12 ▶	13	

Note: *Do not use Part II or Part III below for listed property. Instead, use Part V.*

Part II **Special Depreciation Allowance and Other Depreciation** (Do not include listed property.)

14	Special depreciation allowance for qualified property (see instructions) (other than listed property) placed in service during the tax year	14	Not allowed for Georgia purposes
15	Property subject to IRC Section 168(f)(1) election	15	
16	Other depreciation (including ACRS)	16	2,369,819.

Part III **MACRS Depreciation** (Do not include listed property.)

Section A

17	MACRS deductions for assets placed in service in tax years beginning before 2016	17	300,547,353.
18	If you are electing under IRC Section 168(i)(4) to group any assets placed in service during the tax year into one or more general asset accounts, check here ☐		

Section B -- Assets Placed in Service During 2016 Tax Year Using the General Depreciation System

(a) Classification of property	(b) Month and year placed in service	(c) Basis for depreciation (business/investment use only.) See IRS instructions	(d) Recovery period	(e) Convention	(f) Method	(g) Depreciation deduction
19a 3-year property						
b 5-year property		6,130,010.				1,226,002.
c 7-year property		24,589,236.				3,512,816.
d 10-year property						
e 15-year property		149,258,455.				7,462,924.
f 20-year property		195,306,436.				7,325,056.
g 25-year property			25 yrs		S/L	
h Residential rental property			27.5 yrs.	MM	S/L	
			27.5 yrs.	MM	S/L	
i Nonresidential real property		179,129.	39 yrs	MM	S/L	2,296.
				MM	S/L	

Part IV **Section C -- Assets Placed in Service During 2016 Tax Year Using the Alternative Depreciation System**

20a Class life					S/L	
b 12-year			12 yrs		S/L	
c 40-year			40 yrs	MM	S/L	

1713501424

Form 4562 (2016) Page 2

Summary (See IRS instructions)

21	Listed property. Enter amount from line 28	21	
22	Total. Add amounts from line 12, lines 14 through 17, lines 19 and 20 in column (g), and line 21. Enter here and on the appropriate lines of your return	22	322,446,266.
23	For assets shown above and placed in service during the current year, enter the portion of the basis attributable to IRC Section 263A costs	23	

Part V **Listed Property** (Include automobiles, certain other vehicles, cellular telephones, certain computers, and property used for entertainment, recreation, or amusement.)

Note: *For any vehicle for which you are using the standard mileage rate or deducting lease expense, complete only 24a, 24b, columns (a) through (c) of Section A, all of Section B, and Section C if applicable.*

Section A--Depreciation and Other Information (Caution: See IRS instructions for limits for passenger automobiles.)

24a Do you have evidence to support the business/investment use claimed? Yes ☐ No ☐ 24b If "Yes", is the evidence written? Yes ☐ No ☐

(a) Type of property (list vehicles first)	(b) Date placed in service	(c) Business/ investment use percentage	(d) Cost or other basis	(e) Basis for depreciation (business/investment use only)	(f) Recovery period	(g) Method/ Convention	(h) Depreciation deduction	(i) Elected section 179 cost
25 Special depreciation allowance for qualified listed property placed in service during the tax year and used more than 50% in a qualified business use (see instructions)						25	Not Allowed for Georgia Purposes	
26 Property used more than 50% in a qualified business use:								
		%						
		%						
		%						
27 Property used 50% or less in a qualified business use:								
		%				S/L-		
		%				S/L-		
		%				S/L-		
28 Add amounts in column (h), lines 25 through 27. Enter here and on line 21, page 1						28		
29 Add amounts in column (i), line 26. Enter here and on line 7, page 1							29	

Section B--Information on Use of Vehicles

Complete this section for vehicles used by a sole proprietor, partner, or other "more than 5% owner," or related person. If you provided vehicles to your employees, first answer the questions in Section C to see if you meet an exception to completing this section for those vehicles.

	(a) Vehicle 1		(b) Vehicle 2		(c) Vehicle 3		(d) Vehicle 4		(e) Vehicle 5		(f) Vehicle 6	
30 Total business/investment miles driven during the year (do **not** include commuting miles)												
31 Total commuting miles driven during the year												
32 Total other personal (noncommuting) miles driven												
33 Total miles driven during the year. Add lines 30 through 32												
	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
34 Was the vehicle available for personal use during off-duty hours?												
35 Was the vehicle used primarily by a more than 5% owner or related person?												
36 Is another vehicle available for personal use?												

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Section C--Questions for Employers Who Provide Vehicles for Use by Their Employees

Answer these questions to determine if you meet an exception to completing Section B for vehicles used by employees who are not more than 5% owners or related persons.

		Yes	No
37	Do you maintain a written policy statement that prohibits all personal use of vehicles, including commuting, by your employees?		
38	Do you maintain a written policy statement that prohibits personal use of vehicles, except commuting, by your employees? See IRS instructions for vehicles used by corporate officers, directors, or 1% or more owners		
39	Do you treat all use of vehicles by employees as personal use?		
40	Do you provide more than five vehicles to your employees, obtain information from your employees about the use of the vehicles, and retain the information received?		
41	Do you meet the requirements concerning qualified automobile demonstration use?		

Note: *If your answer to 37, 38, 39, 40, or 41 is "Yes," do not complete Section B for the covered vehicles.*

Part VI Amortization

(a) Description of costs	(b) Date amortization begins	(c) Amortizable amount	(d) Code section	(e) Amortization period or percentage	(f) Amortization for this year
42 Amortization of costs that begins during your 2016 tax year (See IRS instructions):					
					2,689,942
43 Amortization of costs that began before your 2016 tax year				43	7,516,321
44 Total. Add amounts in column (f)				44	10,206,263

Georgia 600, Page 2 Detail

Sch 4, line 8 - Other additions to federal taxable income

	473,833,623.
Total	473,833,623.

Sch 5, line 4 - Other subtractions from federal taxable income

	365,981,990.
Total	365,981,990.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

IT-Addback Section C Information for Additional Related Members

1. Name of the related member .... SCANA SERVICES INC

2. Federal ID number of the related member 57-1092169

3. Amount of costs paid to the related member .. 310,962.

Line 4 State Name	Line 5 Type of Tax	Line 6 Rel. Mem. Costs	Line 7 App Ratio	Line 8 Apportioned Cost
SOUTH CAROLINA	INCOME	310,962.	0.980000	304,743.
NORTH CAROLINA	INCOME	310,962.	0.020000	6,219.

9. Total amount eligible for this exception .... 310,962.

10. Provide a brief description of the arm's length status of the transactions between the taxpayer and the related member.

THE PARTIES ESTABLISHED A MONEY POOL TO COORDINATE AND PROVIDE FOR CERTAIN OF THEIR SHORT-TERM CASH AND WORKING CAPITAL REQUIREMENTS. INTEREST IS CHARGED DAILY BASED ON HIGH GRADE UNSECURED 30 DAY COMMERCIAL PAPER AS QUOTED IN THE WSJ.

Statement 2

FORMS (TAX)

FORM NUMBER

STATE 1120

JURISDICTION

IOWA

MONTH

YEAR

2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

6D1813 3 000
Iowa Department of
REVENUE

2016 IA 1120
Iowa Corporation Income Tax Return
https //tax iowa gov

Step 1
Tax Period 01/01/2016 to 12/31/2016 ▲
Check the box if Address Change ☐
Short Period ▲ ☐

Postmark ▲ | Office Use Only

Corporation Name and Address ▲

Federal Employer Identification Number (FEIN) 57-0248695 ▲
County No 00 ▲ Business Code 221100 ▲

SOUTH CAROLINA ELECTRIC and GAS COMPANY
220 OPERATION WAY
CAYCE 29033-3701

Is this a first or final return? If yes, check the appropriate box.
First Return ▲ New Business ☐ Successor ☐ Entering Iowa ☐
Reorganized ☐ Merged ☐ Dissolved ☐
Final Return ▲ Withdrawn ☐ Bankruptcy ☐ Other ☐

Name of contact person JAMES SWAN IV
Phone 803-217-9000

Step 2 Filing Status
Filing Status ▲ 1 Separate Iowa/Separate Federal ☐ 2 Separate Iowa/Consolidated Federal [X] 3 Consolidated Iowa/Consolidated Federal ☐
Type of Return ▲ 1 Regular Corporation [X] 2 Cooperative ☐ 3 UBIT ☐
Is this an inactive corporation? ▲ Yes ☐ No [X]
Was federal income or tax changed for any prior period? ▲ Yes ☐ No [X] Period(s)
Do you have property in Iowa? ▲ Yes ☐ No [X]

Step	Line	Description		Use whole dollars
Step 3 Net Income and Additions to Income	1	Net Income from federal return before federal net operating loss	1	-29,736,612. ▲
	2	50% of federal tax refund . Accrual [X] Cash ☐	2	▲
	3	Other additions from Schedule A	3	107,851,633. ▲
	4	Net Income after additions Add lines 1 through 3	4	78,115,021.
Step 4 Reductions to Income	5	50% of federal tax paid or accrued Accrual [X] Cash ☐ ▲ 5 NONE ▲		
	6	Other reductions from Schedule A 6 ▲		
	7	Total reductions Add lines 5 and 6	7	NONE
	8	Net income after reductions Subtract line 7 from line 4	8	78,115,021.
Step 5 Taxable Income	9	Nonbusiness income from Schedule D, line 17	9	-1,371,974. ▲
	10	Income subject to apportionment Subtract line 9 from line 8	10	79,486,995.
	11	Iowa percentage from Schedule E See instructions	11	NONE% ▲
	12	Income apportioned to Iowa Multiply line 10 by line 11	12	NONE
	13	Iowa nonbusiness income from Schedule D, line 8	13	-1,371,974. ▲
	14	Income before Net Operating Loss Add lines 12 and 13	14	-1,371,974.
	15	Net Operating Loss Carryforward from Schedule F Include Schedule F	15	▲
	16	Income subject to tax Subtract line 15 from line 14 Do not enter an amount below $0	16	NONE
Step 6 Tax, Credits and Payments	17	Computed tax For tax rates, see bottom of page 3 Check box if tax is annualized ☐	17	NONE ▲
	18	Alternative Minimum Tax from IA Corp Form 4626 Check box if claiming small business exemption ☐	18	NONE ▲
	19	Total tax Add lines 17 and 18	19	NONE
	20	Credits from Schedule C1, line 4 Do not include estimated tax credit 20 ▲		
	21	Payments from Schedule C2, line 4 21 ▲		
	22	Total credits and payments Add lines 20 and 21	22	
	23	Net amount Subtract line 22 from line 19	23	NONE
Step 7 Balance Due	24	Tax due if line 23 is greater than $0	24	NONE
	25	Penalty, underpayment of estimated tax Include IA 2220	25	▲
	26	Penalty, failure to timely pay or failure to timely file	26	▲
	27	Interest	27	▲
	28	Total amount due Add lines 24 through 27 Pay electronically, or submit payment with form IA 1120V	28	NONE ▲
Step 8 Overpayment	29	Overpayment if line 23 is less than $0	29	
	30	Credit to next period's estimated tax	30	▲
	31	Refund requested Subtract line 30 from line 29	31	▲

Form **7004** (Rev December 2016) Department of the Treasury Internal Revenue Service

Application for Automatic Extension of Time To File Certain Business Income Tax, Information, and Other Returns

▶ File a separate application for each return

▶ Information about Form 7004 and its separate instructions is at *www.irs.gov/form7004*.

OMB No 1545-0233

Print or Type	
Name: SCANA CORPORATION	Identifying number: 57-0784499
Number, street, and room or suite no (If P O box, see instructions): 220 OPERATION WAY	
City, town, state, and ZIP code (If a foreign address, enter city, province or state, and country (follow the country's practice for entering postal code)): CAYCE, SC 29033-3701	

Note: File request for extension by the due date of the return for which the extension is granted See instructions before completing this form.

Part I Automatic Extension for C Corporations With Tax Years Ending December 31. See instructions

1a Enter the form code for the return listed below that this application is for 1 2

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part II Automatic Extension for Certain Estates and Trusts. See instructions

b Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1041 (estate other than a bankruptcy estate)	04	Form 1041 (trust)	05

Part III Automatic Extension for Entities Not Using Part I, II, or IV. See instructions.

c Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 706-GS(D)	01	Form 1120-ND (section 4951 taxes)	20
Form 706-GS(T)	02	Form 1120-PC	21
Form 1041 (bankruptcy estate only)	03	Form 1120-POL	22
Form 1041-N	06	Form 1120-REIT	23
Form 1041-QFT	07	Form 1120-RIC	24
Form 1042	08	Form 1120S	25
Form 1065	09	Form 1120-SF	26
Form 1065-B	10	Form 3520-A	27
Form 1066	11	Form 8612	28
Form 1120	12	Form 8613	29
Form 1120-C	34	Form 8725	30
Form 1120-F	15	Form 8804	31
Form 1120-FSC	16	Form 8831	32
Form 1120-H	17	Form 8876	33
Form 1120-L	18	Form 8924	35
Form 1120-ND	19	Form 8928	36

Part IV Automatic Extension for C Corporations With Tax Years Ending June 30. See instructions.

d Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

For Privacy Act and Paperwork Reduction Act Notice, see separate instructions. Form **7004** (Rev 12-2016)

JSA

6X0916 3.000

Form 7004 (Rev 12-2016) Page 2

Part V All Filers Must Complete This Part

2 If the organization is a foreign corporation that does not have an office or place of business in the United States, check here ▶ ☐

3 If the organization is a corporation and is the common parent of a group that intends to file a consolidated return, check here ▶ ☒

If checked, attach a statement listing the name, address, and Employer Identification Number (EIN) for each member covered by this application

4 If the organization is a corporation or partnership that qualifies under Regulations section 1.6081-5, check here ▶ ☐

5a The application is for calendar year 20 16 , or tax year beginning ________, 20 ___ , and ending ________, 20 ___

b **Short tax year.** If this tax year is less than 12 months, check the reason ☐ Initial return ☐ Final return ☐ Change in accounting period ☐ Consolidated return to be filed ☐ Other (see instructions - attach explanation)

6	Tentative total tax	6	6,000,000.
7	Total payments and credits (see instructions)	7	6,000,000.
8	Balance due. Subtract line 7 from line 6 (see instructions)	8	

Form **7004** (Rev 12-2016)

SCANA CORPORATION 57-0784499

Form 7004 - Affiliated Group Members

Name	Employer ID	Name	Employer ID
SCANA SERVICES INC	57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695
SOUTH CAROLINA FUEL CO INC	57-0691209	SC GENERATING COMPANY INC	57-0784498
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908	SCANA ENERGY MARKETING INC	57-0850977
SERVICECARE INC	57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	56-2128483
CLEAN ENERGY ENTERPRISES INC	56-1078443	PSNC BLUE RIDGE CORPORATION	56-1791764
PSNC CARDINAL PIPELINE COMPANY	56-1955423	SCANA CORPORATE SECURITY SERVICES INC	20-0989017

Statement 1

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IA 1120 Page 2, 2016

Schedule A - Other Additions and Reductions

Type of Income	Other Additions	Other Reductions
1 Percentage Depletion		
2 TIP Credit from federal form 8846		
3 Capital Loss Adjustments for filing status 2 or 3		
4 Contribution Adjustments for filing status 2 or 3		
5 Safe Harbor Lease - Rent		
6 Safe Harbor Lease - Interest		
7 Safe Harbor Lease - Depreciation		
8 Depreciation Adjustment from IA 4562A	107,851,633.	
9 Tax Exempt Interest and Dividends See instructions		
10 Iowa Tax Expense/Refund		
11 Work Opportunity Credit Wage Reduction from federal form 5884		
12 Alcohol & Cellulosic Biofuel Credit from federal form 6478		
13 Foreign Dividend Exclusion from Schedule B below		▲
14 Federal Securities Interest and Dividends See instructions		
15 Other Must include schedule	▲	▲
16 Totals	107,851,633.	
	Enter total on line 3 of page 1	Enter total on line 6 of page 1

Schedule B - Foreign Dividend Exclusion

Type of Dividend Income	Total Dividend	Exclusion
1 Less than 20% owned	x 70%	
2 20% to 80% owned	x 80%	
3 More than 80% owned	x 100%	
4 Dividend gross-up (federal section 78)	x 100%	

5 Total Add lines 1 through 4 Enter on line 13 of Schedule A above . . . . ________

Schedule C1 - Credits Amount

1 Fuel Credit Include IA 4136 . . . . ________ ▲
2 Total Nonrefundable Credits Include IA 148 . . . ________ ▲
3 Total Refundable Credits, excluding Fuel Credit Include IA 148 . . . . ________ ▲
4 Total Credits Add lines 1-3 Enter on page 1, line 20 . . . . ________

Schedule C2 - Payments Amount

1 Estimated Tax Payments
a Credit from prior period . . . . ________
b First quarter . . . . ________
c Second quarter . . . . ________
d Third quarter . . . . ________
e Fourth quarter . . . . ________
f Other . . . . ________
2 Voucher Payment . . . . ________
3 Other Payments Include statement . . . . . ________
4 Total Add lines 1-3 Enter on page 1, line 21 . ________

Additional Information

1 Year business was started in Iowa N/A
2 Last period filed as S corporation (if any) ________
3 Information from the prior period Iowa return
Corporation name SOUTH CAROLINA ELECTRIC and GAS COMPANY
Net Income/Loss -856,776. ▲
FEIN 57-0248695 ▲
4 If part of a federal consolidated group, please provide information about the Corporate parent
Corporation name SCANA CORPORATION
FEIN 57-0784499 ▲

6D1818 1 000

IA 1120 Page 3, 2016

Schedule E - Business Activity Ratio (BAR) (see instructions)

	Type of Income	Column A Iowa Receipts	Column B Receipts Everywhere	
1	Gross Receipts	▲	3,015,062,430.	▲ 1
2	Net Dividends See instructions			▲ 2
3	Exempt Interest from line 9, Schedule A			▲ 3
4	Accounts Receivable Interest			▲ 4
5	Other Interest			▲ 5
6	Rent			▲ 6
7	Royalties			▲ 7
8	Capital Gain			▲ 8
9	Ordinary Gain			▲ 9
10	Partnership Gross Receipts Include schedule			▲10
11	Other Must include schedule	▲		▲11
12	Totals	▲	3,015,062,430.	▲12

13 Divide column A total by column B total For example, 0 1234505 becomes 12 3451% Enter % on line 11, page 1 NONE%

A complete copy of your federal return, as filed with the Internal Revenue Service, must be filed with this return For filing status 2 or 3, you must include pages 1-5 of your consolidated federal return, consolidating income statements, Iowa Schedule H and any other forms related to the Iowa return

Tax Rates
If income shown on line 16 (of page 1) is
- Under $25,000, multiply line 16 by 6%
- $25,000 to $100,000, multiply line 16 by 8% and subtract $500
- $100,000 to $250,000, multiply line 16 by 10% and subtract $2,500
- Over $250,000, multiply line 16 by 12% and subtract $7,500

If annualizing, include a schedule showing computation

To obtain schedules and forms
Website https //tax iowa gov
Tax Research Library http //itrl idr iowa gov/
Questions
515-281-3114 or 800-367-3388
Email. idr@iowa gov
eFile or mail your return to
Corporation Tax Return Processing
Iowa Department of Revenue
PO Box 10468
Des Moines, IA 50306-0468

Under penalties of perjury, I declare that I have examined this return and any schedules/statements, and, to the best of my knowledge believe it to be true, correct and complete If prepared by a person other than the taxpayer, the declaration is based on all information of which there is any knowledge

Officer's signature ________ Title CONTROLLER Date 10/11/2017

Signature of preparer if other than taxpayer ________ Date ________

Name and address of preparer or preparer's employer

Preparer's telephone No ________

Preparer's ID No ________ ▲

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

42-001c (07/18/16) THB
00000ZR M16C 10/09/2017 14:48:06 V16-7.1F 57-0248695 6

6D1637 3 000

Iowa Department of
REVENUE

IA Corporation Schedule D - Non Business Income

https //tax iowa gov

If all corporate business is conducted within Iowa, do not complete Schedule D.
The classification of income by the labels customarily given them, such as interest, dividends, rents, and royalties, is of no aid in determining whether that income is business or nonbusiness income Please provide all documentation to the Department showing why the income must be allocated as nonbusiness income

Instructions When referring to the columns designated below, enter the amounts on lines 1 through 8 if the corporation's commercial domicile is Iowa Enter amounts on lines 9 through 16 if the corporation's commercial domicile is outside Iowa However, rent, royalty, and capital or ordinary gain income from real or tangible personal property is allocated to the situs of the property producing the income Also, see Iowa Admin Code r 701- 54 2(3) for attribution of income from intangibles

Column A Gross Income: Enter the amount of income on the appropriate line. If an entry is made on line 6 or 14, please include federal Schedule D If an entry is made on line 1, do not include any amounts previously deducted on line 13 of Iowa Schedule A relating to foreign dividends

Column B Related Expense: Enter directly-related expenses and indirectly-related interest expenses on the appropriate line Include detailed schedules showing the computation of the related expense

Column C Subtotal: Subtract column B from column A and enter the difference

Column D 50% of Applicable Federal Income Tax: Enter 50% of the applicable federal income tax. Do not enter negative amounts The effective tax rate equals line 5 divided by line 1 of form IA 1120 Multiply column C by this tax rate to determine the entry for column D The total amount is limited to the federal tax deduction shown on line 5, IA 1120

Column E Net Income: Subtract column D from column C and enter the difference

Allocated Within Iowa

Type of Income	A Gross Income	B Related Expenses	C Subtotal	D 50% of Applicable Federal Income Tax	E Net Income
1 Net Dividend See Instructions					
2 Exempt Interest and Dividends					
3 Other Interest					
4 Rent					
5 Royalties					
6 Capital Gain					
7 Other Must include schedule	Stmt 1 -1,371,974.		-1,371,974.		-1,371,974.

8 Subtotal Add column E, lines 1 through 7 Enter on line 13, IA 1120 . . . . . 8 -1,371,974.

Allocated Without Iowa

Type of Income	A Gross Income	B Related Expenses	C Subtotal	D 50% of Applicable Federal Income Tax	E Net Income
9 Net Dividend See Instructions					
10 Exempt Interest and Dividends					
11 Other Interest					
12 Rent					
13 Royalties					
14 Capital Gain					
15 Other Must include schedule					

16 Subtotal Add column E, lines 9 through 15 16

17 Total Add column E, lines 8 and 16 Enter on line 9, IA 1120 . . . . . 17 -1,371,974.

42-014 (10/14/16) THO

6D1821 2 000

Iowa Department of
REVENUE

2016 IA Corporate Form 4626

Iowa Alternative Minimum Tax

https //tax iowa gov

Corporate Name SOUTH CAROLINA ELECTRIC and GAS COMPANY
FEIN 57-0248695

Ending Tax Period (mm/dd/yy) 12 / 31 / 16
All totals are from federal form 4626 except as noted Federal form 4626 must be enclosed

			Enter Whole Dollars
1.	Income subject to apportionment from line 10, IA 1120	1	79,486,995.
2.	Total adjustments and preferences	2	-18,835,808.
3	Preferences not applicable for Iowa		
	a Depletion ... 3a		
	b Tax exempt interest from Private Activity Bonds 3b		
	c Total Add lines 3a and 3b	3c	
4	Total Iowa Tax Preferences Subtract line 3c from line 2	4	-18,835,808.
5	Total of lines 1 and 4	5	60,651,187.
6	Adjusted Current Earnings Adjustment See instructions.	6	3,942,786.
7.	Total of lines 5 and 6	7	64,593,973.
8	Iowa Percentage from line 11, IA 1120	8	NONE
9	Income Apportioned to Iowa Multiply line 7 by line 8	9	NONE
10.	Iowa Nonbusiness Income from line 13, IA 1120	10	-1,371,974.
11	Add lines 9 and 10.	11	-1,371,974.
12	Iowa Alternative Minimum Tax Net Operating Loss Total from IA Form G, column E Limited to 90% of line 11	12	
13	Iowa Alternative Minimum Taxable Income before Exemption Subtract line 12 from line 11	13	-1,371,974.
14	Exemption See instructions	14	
15	Iowa Alternative Minimum Taxable Income Subject to Tax Subtract line 14 from line 13 If less than zero, enter zero	15	
16	Iowa Tentative Minimum Tax Multiply line 15 by 7 2%	16	NONE
17	Iowa Regular Tax from line 17, IA 1120	17	NONE
18	Iowa Alternative Minimum Tax Subtract line 17 from line 16 but not below zero Enter on line 18, IA 1120.	18	NONE

42-003a (09/28/16) THO

6Y1612 1 000
Iowa Department of
REVENUE

2016 IA 4562A
Iowa Depreciation Adjustment Schedule
https //tax iowa gov

Include this form with your Iowa income tax return

Name(s) SOUTH CAROLINA ELECTRIC and GAS COMPANY SSN or FEIN 57-0248695

Pass-Through Entity (if applicable) ______ Pass-Through FEIN ______

Part I - Computation of Iowa depreciation adjustment

A Description of Property	B Date Placed in Service	C Life of Asset	D Cost or Other Basis	E Federal 179 Expense	F Federal Depreciation Deduction	G Accumulated Federal Depreciation	H Iowa 179 Expense	I MACRS Iowa Depreciation Deduction	J Accumulated Iowa Depreciation
See attached IA 4562A detail for Part I									
Total amounts in columns E, F, H, and I					473,833,623.			365,981,990.	

Part II - Disposition adjustments
If you have disposed of bonus depreciation or section 179 property, and an Iowa depreciation adjustment was applied to this property in a prior year, continue with Part II, otherwise, skip to Part III

A Description of Property Sold or Disposed	B Date Placed in Service - mo/day/yr	C Date Sold or Disposed	D Total Iowa Depreciation + Sec 179 expense taken	E Total Federal Depreciation + Sec 179 Expense Taken	F Adjustment (subtract column E from column D)
				Total amounts in column F	

Part III - Summary of adjustments to net income

1 Enter the sum of amounts from Part I, columns E and F . . . . 1 473,833,623.
2 Enter the sum of amounts from Part I, columns H and I . . . . 2 365,981,990.
3 Adjustment to depreciation Subtract line 2 from line 1 . . . . 3 107,851,633.
4 Enter the amount from Part II, column F 4
5 Add lines 3 and 4 This amount must be reported on your tax return
See table in Part III of the instructions for specific form and line references . . 5 107,851,633.

41-105a (06/01/16)

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Iowa Department of
REVENUE

2016 IA 4562B

Iowa Accumulated Depreciation Adjustment Schedule

https //tax.iowa gov

Name(s) SOUTH CAROLINA ELECTRIC and GAS COM SSN/FEIN 57-0248695

Pass-Through Entity (if applicable) Pass-Through FEIN

Note Use this form to record the cumulative effect of the Bonus Depreciation Adjustment computed on form IA 4562A

Tax Period Ending Date	IA 4562A Adjustment Amount from Part III, Line 5	Balance
12/31/2016	107,851,633.	107,851,633.

Instructions

Tax Period Ending Date Start with the tax period that you first made an adjustment for bonus depreciation on the Iowa return Continue entering each subsequent tax period up to, and including, the current period

IA 4562A Adjustment. Enter the amount added/deducted on the Iowa return for each tax period This should be the amount entered in Part III, line 5 of the IA 4562A Enter negative numbers in parenthesis Place an asterisk (*) after the tax period if the IA 4562A adjustment was changed from the amount originally claimed You must provide copies of the prior tax periods' IA 4562As if requested by the Department Failure to provide copies of the prior tax periods' IA 4562As will delay the processing of your return or cause the denial of your adjustment Do not send copies of the asset listings that are required with the IA 4562A

Balance The balance amount for the first tax period should be the same as the amount of the adjustment For each subsequent tax period, the balance amount should be changed by the amount of that tax period's IA 4562A adjustment

Include this form with your IA tax return

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Sch D Detail

Sch D, Line 7 - Other Income - Within Iowa	Gross Income	Related Exp.
LOUISA REFINDED COAL LLC	-1,371,974.	
Total	-1,371,974.	

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Part I - Depreciation Adjustment Detail

Description	Date of Service	Life of asset	Cost	Federal 179 Expense	Federal Depr Deduction	Accumulated Federal Depr	Iowa 179 Expense	MACRS IA Depr Deduct	Accumulated Iowa Depr
VARIOUS	VAR				473,833,623			365,981,990	
			Total		473,833,623			365,981,990	

Form **8453-C**

Department of the Treasury
Internal Revenue Service

U.S. Corporation Income Tax Declaration for an IRS *e-file* Return

▶ File electronically with the corporation's tax return Do not file paper copies
▶ Information about Form 8453-C and its instructions is at www.irs.gov/form8453c

For calendar year 2016, or tax year beginning , ending

OMB No 1545-0123

2016

Name of corporation: SCANA CORPORATION

Employer identification number: 57-0784499

Part I Tax Return Information (Whole dollars only)

1	Total income (Form 1120, line 11)	1	2,612,525,249.
2	Taxable income (Form 1120, line 30)	2	-57,112,028.
3	Total tax (Form 1120, line 31)	3	NONE
4	Amount owed (Form 1120, line 34)	4	
5	Overpayment (Form 1120, line 35)	5	6,237,866.

Part II Declaration of Officer (see instructions) Be sure to keep a copy of the corporation's tax return.

6a [X] I consent that the corporation's refund be directly deposited as designated on the Form 8050, Direct Deposit of Corporate Tax Refund, that will be electronically transmitted with the corporation's 2016 federal income tax return

b [ ] I do not want direct deposit of the corporation's refund or the corporation is not receiving a refund

c [ ] I authorize the U S Treasury and its designated Financial Agent to initiate an electronic funds withdrawal (direct debit) entry to the financial institution account indicated in the tax preparation software for payment of the corporation's federal taxes owed on this return, and the financial institution to debit the entry to this account To revoke a payment, I must contact the U S Treasury Financial Agent at 1-888-353-4537 no later than 2 business days prior to the payment (settlement) date I also authorize the financial institutions involved in the processing of the electronic payment of taxes to receive confidential information necessary to answer inquiries and resolve issues related to the payment

If the corporation is filing a balance due return, I understand that if the IRS does not receive full and timely payment of its tax liability, the corporation will remain liable for the tax liability and all applicable interest and penalties

Under penalties of perjury, I declare that I am an officer of the above corporation and that the information I have given my electronic return originator (ERO), transmitter, and/or intermediate service provider (ISP) and the amounts in Part I above agree with the amounts on the corresponding lines of the corporation's 2016 federal income tax return To the best of my knowledge and belief, the corporation's return is true, correct, and complete I consent to my ERO, transmitter, and/or ISP sending the corporation's return, this declaration, and accompanying schedules and statements to the IRS I also consent to the IRS sending my ERO, transmitter, and/or ISP an acknowledgment of receipt of transmission and an indication of whether or not the corporation's return is accepted, and, if rejected, the reason(s) for the rejection If the processing of the corporation's return or refund is delayed, I authorize the IRS to disclose to my ERO, transmitter, and/or ISP the reason(s) for the delay, or when the refund was sent

Sign Here ▶ Signature of officer | 09/28/2017 Date | ▶ CONTROLLER Title

Part III Declaration of Electronic Return Originator (ERO) and Paid Preparer (see instructions)

I declare that I have reviewed the above corporation's return and that the entries on Form 8453-C are complete and correct to the best of my knowledge If I am only a collector, I am not responsible for reviewing the return and only declare that this form accurately reflects the data on the return The corporate officer will have signed this form before I submit the return I will give the officer a copy of all forms and information to be filed with the IRS, and have followed all other requirements in Pub 3112, IRS *e-file* Application and Participation, and Pub 4163, Modernized e-File (MeF) Information for Authorized IRS *e-file* Providers for Business Returns If I am also the Paid Preparer, under penalties of perjury, I declare that I have examined the above corporation's return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete This Paid Preparer declaration is based on all information of which I have any knowledge

ERO's Use Only	ERO's signature ▶	Date	Check if also paid preparer [X]	Check if self-employed [ ]	ERO's SSN or PTIN
	Firm's name (or yours if self-employed), address, and ZIP code ▶				EIN
					Phone no

Under penalties of perjury, I declare that I have examined the above corporation's return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete This declaration is based on all information of which I have any knowledge

Paid Preparer Use Only	Print/Type preparer's name	Preparer's signature	Date	Check [ ] if self-employed	PTIN
	Firm's name ▶			Firm's EIN ▶	
	Firm's address ▶			Phone no	

0000ZT M16C 09/28/2017 11:48:17 V16-7F 57-0784499

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2016 or tax year beginning ____________, ending ____________

▶ Information about Form 1120 and its separate instructions is at www.irs.gov/form1120.

OMB No 1545-0123 **2016**

A Check if: 1a Consolidated return (attach Form 851) [X]; b Life/nonlife consolidated return [ ]; 2 Personal holding co (attach Sch PH) [ ]; 3 Personal service corp (see instructions) [ ]; 4 Schedule M-3 attached [X]

TYPE OR PRINT

Name: SCANA CORPORATION

Number, street, and room or suite no If a P O box, see instructions: 220 OPERATION WAY

City or town, state, or province, country, and ZIP or foreign postal code: CAYCE, SC 29033-3701

B Employer identification number: 57-0784499

C Date incorporated: 10/01/1984

D Total assets (see instructions): $ 18,706,879,069.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Income			
1a	Gross receipts or sales	1a	4,497,365,433.
b	Returns and allowances	1b	
c	Balance Subtract line 1b from line 1a	1c	4,497,365,433.
2	Cost of goods sold (attach Form 1125-A)	2	2,118,180,744.
3	Gross profit Subtract line 2 from line 1c	3	2,379,184,689.
4	Dividends (Schedule C, line 19)	4	337,492.
5	Interest	5	241,238,458.
6	Gross rents	6	15,809,392.
7	Gross royalties	7	
8	Capital gain net income (attach Schedule D (Form 1120))	8	230,794.
9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)	9	-51,771,917.
10	Other income (see instructions - attach statement) See Statement 4	10	27,496,341.
11	**Total income** Add lines 3 through 10 ▶	11	2,612,525,249.
Deductions (See instructions for limitations on deductions)			
12	Compensation of officers (see instructions - attach Form 1125-E) ▶	12	15,144,833.
13	Salaries and wages (less employment credits)	13	80,503,050.
14	Repairs and maintenance	14	248,721,590.
15	Bad debts	15	10,347,235.
16	Rents	16	4,696,539.
17	Taxes and licenses	17	256,620,275.
18	Interest	18	385,177,623.
19	Charitable contributions See Statement 6	19	NONE
20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)	20	674,906,524.
21	Depletion	21	
22	Advertising	22	12,485,413.
23	Pension, profit-sharing, etc, plans	23	694,957.
24	Employee benefit programs	24	56,802,808.
25	Domestic production activities deduction (attach Form 8903)	25	
26	Other deductions (attach statement) See Statement 7	26	923,324,230.
27	**Total deductions** Add lines 12 through 26 ▶	27	2,669,425,077.
28	Taxable income before net operating loss deduction and special deductions Subtract line 27 from line 11	28	-56,899,828.
29a	Net operating loss deduction (see instructions) — 29a: NONE		Stmt 10
b	Special deductions (Schedule C, line 20) — 29b: 212,200.		
c	Add lines 29a and 29b	29c	212,200.
Tax, Refundable Credits, and Payments			
30	**Taxable income.** Subtract line 29c from line 28 See instructions	30	-57,112,028.
31	Total tax (Schedule J, Part I, line 11)	31	NONE
32	Total payments and refundable credits (Schedule J, Part II, line 21)	32	6,237,866.
33	Estimated tax penalty See instructions Check if Form 2220 is attached ▶ [ ]	33	
34	**Amount owed** If line 32 is smaller than the total of lines 31 and 33, enter amount owed	34	
35	**Overpayment** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid	35	6,237,866.
36	Enter amount from line 35 you want Credited to 2017 estimated tax ▶ Refunded ▶	36	6,237,866.

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge

Signature of officer: JAMES E SWAN IV | Date: 09/28/2017 | Title: CONTROLLER

May the IRS discuss this return with the preparer shown below? See instructions [ ] Yes [X] No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check [ ] if self-employed	PTIN

Firm's name ▶ | Firm's EIN ▶

Firm's address ▶ | Phone no

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 2

Schedule C Dividends and Special Deductions (see instructions)	(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	303,143.	70	212,200.
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3 Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8 Dividends from wholly owned foreign subsidiaries		100	
9 Total Add lines 1 through 8 See instructions for limitation			212,200.
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members		100	
12 Dividends from certain FSCs		100	
13 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, or 12	34,349.		
14 Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15 Foreign dividend gross-up			
16 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
17 Other dividends			
18 Deduction for dividends paid on certain preferred stock of public utilities			
19 **Total dividends** Add lines 1 through 17 Enter here and on page 1, line 4 ▶	337,492.		
20 **Total special deductions.** Add lines 9, 10, 11, 12, and 18 Enter here and on page 1, line 29b ▶			212,200.

Form **1120** (2016)

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 3

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)) See instructions ▶ ☐				
2	Income tax Check if a qualified personal service corporation See instructions. ▶ ☐			2	
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	NONE
5a	Foreign tax credit (attach Form 1118)	5a			
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c			
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	Total credits Add lines 5a through 5e			6	
7	Subtract line 6 from line 4			7	NONE
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	Total Add lines 9a through 9f			10	
11	Total tax Add lines 7, 8, and 10 Enter here and on page 1, line 31			11	NONE

Part II-Payments and Refundable Credits

12	2015 overpayment credited to 2016			12	
13	2016 estimated tax payments			13	6,000,000.
14	2016 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	6,000,000.
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	Total payments Add lines 15, 16, and 17			18	6,000,000.
19	Refundable credits from				
a	Form 2439	19a			
b	Form 4136	19b	237,866.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	Total credits Add lines 19a through 19d			20	237,866.
21	Total payments and credits Add lines 18 and 20 Enter here and on page 1, line 32			21	6,237,866.

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the		
a	Business activity code no ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 4

Schedule K Other Information *(continued from page 3)*

	Yes	No
5 At the end of the tax year, did the corporation		
a Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on Form 851, Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below		X

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock

	Yes	No
b Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below See Statement 14	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital

	Yes	No
6 During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316. If "Yes," file Form 5452, Corporate Report of Nondividend Distributions. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		X
7 At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of (a) the total voting power of all classes of the corporation's stock entitled to vote or (b) the total value of all classes of the corporation's stock? For rules of attribution, see section 318. If "Yes," enter (i) Percentage owned ▶ ______ and (ii) Owner's country ▶ ______ (c) The corporation may have to file Form 5472, Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ ______		X
8 Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐ If checked, the corporation may have to file Form 8281, Information Return for Publicly Offered Original Issue Discount Instruments.		
9 Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $ ______		
10 Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶ ______		
11 If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here ▶ ☐ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election won't be valid.		
12 Enter the available NOL carryover from prior tax years (don't reduce it by any deduction on line 29a.) ▶ $ ______		
13 Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year and its total assets at the end of the tax year less than $250,000?		X
If "Yes," the corporation isn't required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $ ______		
14 Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions. If "Yes," complete and attach Schedule UTP.	X	
15a Did the corporation make any payments in 2016 that would require it to file Form(s) 1099?	X	
b If "Yes," did or will the corporation file required Forms 1099?	X	
16 During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17 During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18 Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19 During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?	X	

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 5

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	Beginning of tax year (b)	End of tax year (c)	End of tax year (d)
1 Cash		236,349,831.		207,880,557.
2a Trade notes and accounts receivable	682,391,843.		733,184,381.	
b Less allowance for bad debts	(5,269,711.)	677,122,132.	(5,853,608.)	727,330,773.
3 Inventories		311,778,910.		290,480,845.
4 U S government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 21	151,782,083.		280,369,350.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 23	240,146,412.		198,711,256.
10a Buildings and other depreciable assets	18,667,897,661.		20,054,957,957.	
b Less accumulated depreciation	(5,975,136,607.)	12,692,761,054.	(5,454,272,723.)	14,600,685,234.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)				
13a Intangible assets (amortizable only)				
b Less accumulated amortization	( )		( )	
14 Other assets (attach statement)	Stmt 24	2,479,478,762.		2,401,421,054.
15 Total assets		16,789,419,184.		18,706,879,069.
Liabilities and Shareholders' Equity				
16 Accounts payable		576,643,248.		388,631,752.
17 Mortgages, notes, bonds payable in less than 1 year		647,291,449.		957,426,831.
18 Other current liabilities (attach statement)	Stmt 27	653,922,195.		719,026,809.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		5,904,834,401.		6,472,928,061.
21 Other liabilities (attach statement)	Stmt 30	3,562,331,009.		4,443,834,268.
22 Capital stock a Preferred stock				
b Common stock	2,417,595,500.	2,417,595,500.	2,417,595,500.	2,417,595,500.
23 Additional paid-in capital		-14,282,362.		-14,282,362.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		3,118,303,738.		3,383,244,353.
26 Adjustments to shareholders' equity (attach statement)		-65,427,485.		-49,050,610.
27 Less cost of treasury stock		(11,792,509.)		(12,475,533.)
28 Total liabilities and shareholders' equity		16,789,419,184.		18,706,879,069.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3 See instructions

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize) Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize)		8 Deductions on this return not charged against book income this year (itemize)	
5 Expenses recorded on books this year not deducted on this return (itemize)		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)

1 Balance at beginning of year	3,118,303,738.	5 Distributions a Cash	329,908,943.
2 Net income (loss) per books	594,849,551.	b Stock	
3 Other increases (itemize)		c Property	
		6 Other decreases (itemize) Stmt 36	-5.
See Statement 36	2.	7 Add lines 5 and 6	329,908,938.
4 Add lines 1, 2, and 3	3,713,153,291.	8 Balance at end of year (line 4 less line 7)	3,383,244,353.

Form **1120** (2016)

JSA
6C1140 2 000

SCANA CORPORATION 57-0784499

Consolidated Schedules
1120 Page 1

		Combined	ELIMINATIONS SCANA CORPORATIO	Adjustments	SCANA CORPORATION
1a	Gross receipts or sales	5,217,353,893.	-719,988,460.		4,497,365,433
1b	Returns and allowances				
1c	Balance	5,217,353,893	-719,988,460		4,497,365,433
2	Cost of goods sold	2,494,537,833	-376,357,089		2,118,180,744
3	Gross profit	2,722,816,060	-343,631,371		2,379,184,689.
4	Dividends	337,492.			337,492
5	Interest	250,673,017.	-9,434,559		241,238,458
6	Gross rents	22,485,964	-6,676,572		15,809,392.
7	Gross royalties				
8	Capital gain net income	232,440		-1,646	230,794
9	Net gain or (loss) from Form 4797	-51,773,563		1,646	-51,771,917.
10	Other income	28,218,759.	-722,418		27,496,341
11	Total income	2,972,990,169	-360,464,920		2,612,525,249
12	Compensation of officers	15,144,833			15,144,833
13	Salaries and wages	196,779,280	-116,276,230		80,503,050
14	Repairs and maintenance	304,310,651	-55,589,061.		248,721,590
15	Bad debts	10,405,142	-57,907		10,347,235
16	Rents	19,818,345	-15,121,806		4,696,539
17	Taxes and licenses	273,148,980	-16,528,705.		256,620,275.
18	Interest	404,903,894	-19,726,271		385,177,623.
19	Charitable contributions	3,585,739.	NONE	-3,585,739	NONE
20	Depreciation	674,906,524			674,906,524.
21	Depletion				
22	Advertising	13,299,533.	-814,120		12,485,413
23	Pension, profit-sharing etc, plans	1,059,828.	-364,871		694,957.
24	Employee benefit programs	86,473,736.	-29,670,928		56,802,808
25	Domestic production activities deduction				
26	Other deductions	1,029,639,251	-106,315,021		923,324,230.
27	Total deductions	3,033,475,736	-360,464,920	-3,585,739	2,669,425,077
28	Taxable income before NOL & Spec Deductions	-60,485,567.	NONE	3,585,739	-56,899,828.
29	NOL,Spec deductions	212,200.			212,200.
30	Taxable income	-60,697,767.	NONE	3,585,739	-57,112,028.

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SCANA CORPORATION 57-0784499

Consolidated Schedules 1120 Page 1	SCANA CORPORATION	SCANA SERVICES INC	SOUTH CAROLINA ELECTRIC and GAS COMPANY	SOUTH CAROLINA FUEL CO INC	SC GENERATING COMPANY INC	SCANA COMMUNICATIONS HOLDINGS INC	SCANA ENERGY MARKETING INC	SERVICECARE INC
	57-0784499	57-1092169	57-0248695	57-0691209	57-0784498	51-0394908	57-0850977	57-1007394
1a Gross receipts or sales		413,279,684	2,998,699,530	237,225,342	193,888,768		938,277,430	
1b Returns and allowances								
1c Balance		413,279,684	2,998,699,530.	237,225,342	193,888,768		938,277,430	
2 Cost of goods sold		74,318,188.	1,088,310,803.	179,355,049	113,725,200.		833,752,358	
3 Gross profit		338,961,496	1,910,388,727	57,870,293	80,163,568		104,525,072	
4 Dividends	337,492							
5 Interest	8,556,558	730,796.	235,401,711		22,261	6,321.	374,179.	5,863
6 Gross rents		735,204.	20,964,105.		10,903			
7 Gross royalties								
8 Capital gain net income	230,794	NONE	NONE				1,646.	
9 Net gain or (loss) from Form 4797		-696,096	-38,024,208.		-3,530,135			
10 Other income	-33,798	722,418	10,233,647		-585,541	1,186,550	10,217	
11 Total income	9,091,046	340,453,818	2,138,963,982.	57,870,293.	76,081,056	1,192,871	104,911,114	5,863
12 Compensation of officers			15,144,833.					
13 Salaries and wages	371,386.	102,987,502	55,188,382	3,529	1,541,100	2,400	16,135,231	2,541.
14 Repairs and maintenance		51,734,339	215,401,652		18,725,651		574,178	356
15 Bad debts		57,907	6,349,958				3,429,159.	-593.
16 Rents		9,357,222	6,587,833.		78,729.	2,400	1,974,447	
17 Taxes and licenses	287,115.	16,538,705	230,655,590	2,978	7,397,963	1,230	3,270,779.	359
18 Interest	54,740,127	9,119,174	297,298,406	1,845,292	14,863,234		1,070,855	
19 Charitable contributions	145.	NONE	2,736,550.		12,417.		453,434	
20 Depreciation		15,840,260	431,921,192	46,060,920	19,590,347		955,303	
21 Depletion								
22 Advertising		814,120	371,874				11,082,729	
23 Pension, profit-sharing etc., plans	-1,502,226	364,871	1,368,809.	11	19,491.		53,040	849,150
24 Employee benefit programs	-2,896,149	29,670,928	43,614,763.	1,038	1,568,904		4,321,315	313,850
25 Domestic production activities deduction								
26 Other deductions	23,866,947	93,283,085	862,060,752	236,577	2,727,592	14,601	13,403,489.	32,380
27 Total deductions	74,867,345	329,768,113.	2,168,700,594	48,150,345	66,525,428	20,631	56,723,959.	1,198,043
28 Taxable income before NOL & Spec. Deductions	-65,776,299	10,685,705	-29,736,612	9,719,948	9,555,628	1,172,240.	48,187,155.	-1,192,180
29 NOL, Spec. deductions	212,200							
30 Taxable income	-65,988,499	10,685,705	-29,736,612	9,719,948	9,555,628	1,172,240.	48,187,155.	-1,192,180

SCANA CORPORATION 57-0784499

Consolidated Schedules 1120 Page 1	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 56-2128483	CLEAN ENERGY ENTERPRISES INC 56-1079443	PSNC BLUE RIDGE CORPORATION 56-1791764	PSNC CARDINAL PIPELINE COMPANY 56-1955423	SCANA CORPORATE SECURITY SERVICES INC 20-0989017
1a Gross receipts or sales	435,983,139				
1b Returns and allowances					
1c Balance	435,983,139				
2 Cost of goods sold	205,076,235.				
3 Gross profit	230,906,904				
4 Dividends					
5 Interest	5,559,623		3,557	12,148	
6 Gross rents	775,752				
7 Gross royalties					
8 Capital gain net income					
9 Net gain or (loss) from Form 4797	-9,523,124.				
10 Other income	11,979,514.		1,615,439	3,090,313	
11 Total income	239,698,669		1,618,996	3,102,461	
12 Compensation of officers					
13 Salaries and wages	20,547,209				
14 Repairs and maintenance	17,874,475.				
15 Bad debts	568,711				
16 Rents	1,817,714.				
17 Taxes and licenses	14,849,692	1,000.	51,371.	92,198.	
18 Interest	25,966,806.				
19 Charitable contributions	383,193				
20 Depreciation	160,538,502				
21 Depletion					
22 Advertising	1,030,810.				
23 Pension, profit-sharing etc., plans	-93,318				
24 Employee benefit programs	9,879,087.				
25 Domestic production activities deduction					
26 Other deductions	34,013,125	703.			
27 Total deductions	287,376,006.	1,703	51,371	92,198	
28 Taxable income before NOL & Spec Deductions	-47,677,337	-1,703.	1,567,625	3,010,263.	NONE
29 NOL, Spec deductions					
30 Taxable income	-47,677,337	-1,703	1,567,625	3,010,263.	NONE

FORMS (TAX)

FORM NUMBER

STATE 1120

JURISDICTION

LOUISIANA

MONTH	YEAR
	2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

R-8453C (1/17) 2395

LOUISIANA
DEPARTMENT of REVENUE

Louisiana Department of Revenue
Corporation Income/Franchise Tax
Declaration for Electronic Filing

2016
LA8453-C

Do not file paper copies. This form is to be maintained by ERO.
For calendar year 2016, or tax year beginning ____________, 2016, ending ____________, 2017

PLEASE PRINT OR TYPE.

Name of Corporation			
SOUTH CAROLINA ELECTRIC and GAS COMPANY			
Louisiana Revenue Account Number: 5556337-001	Federal Employer Identification Number *(FEIN)*: 57-0248695		
Street Address of Corporation: 220 OPERATION WAY	City: CAYCE	State: SC	ZIP: 29033-3701

Part 1 - Tax Return Information (whole dollars only)

1	Income & Franchise tax due after Priority 1 Credits *(Form CIFT-620, Line 10, the sum of both columns 1 and 2)*	1	2,754. .00
2	Refund *(Form CIFT-620, Line 29, column 3)*	2	239,563. .00
3	Total amount due *(Form CIFT-620, Line 26, column 3)*	3	.00
4	Amount of payment remitted electronically	4	.00

Part II - Declaration of Officer (Sign only after Part I is completed.)

Under penalties of perjury, I declare that I am an officer of the above corporation and that the information that I have given my electronic return originator (ERO), transmitter, and/or intermediate service provider (ISP) and the amounts in Part 1 above agree with the amounts on the corresponding lines of the Louisiana 2016 Income/2017 Franchise tax return. To the best of my knowledge and belief, the corporation's return is true, correct, and complete. I consent to my ERO, transmitter, and/or ISP sending the corporation's return, this declaration, accompanying schedules, and statements to the Louisiana Department of Revenue. I also consent to the Louisiana Department of Revenue sending my ERO, transmitter, and/or ISP an acknowledgment of receipt of transmission and an indication of whether or not the corporation's return is accepted, and, if rejected, the reason(s) for the rejection.

☐ I authorize a representative of the Louisiana Department of Revenue to discuss my return and attachments with my preparer.

Signature of Officer	Date *(mm/dd/yyyy)*	Title
X	10/11/2017	CONTROLLER

Part III - Declaration of Electronic Return Originator (ERO) and Paid Preparer

I declare that I have reviewed the above corporation's return and that the entries on LA8453-C are complete and correct to the best of my knowledge. If I am only a collector, I am not responsible for reviewing the return and only declare that this form accurately reflects the data on the return. The corporate office will have signed this form before I submit the return. I will give the officer a copy of all forms and information to be filed with the Louisiana Department of Revenue, and have followed all other requirements in Pub. 3112, IRS E-file Application and Participation, and Pub. 4163, Modernized E-File Information for Authorized IRS E-Providers. If I am also the Paid Preparer, under penalties of perjury I declare that I have examined the above corporation's return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete. This Paid Preparer declaration is based on all information of which I have any knowledge.

ERO's Use Only

ERO'S Signature	Date *(mm/dd/yyyy)*	Check if also paid preparer	Check if self-employed	ERO's SSN or PTIN
X		X	☐	
Firm's Name *(or yours if self-employed)*				EIN
City	State	ZIP		Phone Number

Paid Preparer's Use only

Preparer's Signature	Date *(mm/dd/yyyy)*	Check if self-employed	Preparer's SSN or PTIN
X		☐	
Firm's Name *(or yours if self-employed)*			EIN
City	State	ZIP	Phone Number

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CIFT-620-SD (1/17) Page 1 of 3

Louisiana Department of Revenue
Post Office Box 91011
Baton Rouge, LA 70821-9011

Enter your LA Revenue Account Number here *(Not FEIN)*: 5556337-001

For office use only.

Louisiana Corporation Income Tax Return for 2016 or Fiscal Year	Louisiana Corporation Franchise Tax Return for 2017 or Fiscal Year
Begun ________, 2016	Begun ________, 2017
Ended ________, 2017	Ended ________, 2018

Calendar year returns are due May 15. See instructions for fiscal years.

Final return

Short period return

Mark the appropriate box for Short period or Final return.

Mark box if:

Name change.

Amended return.

Entity is not required to file franchise tax.

First time filing of this form.

Legal Name: SOUTH CAROLINA ELECTRIC and GA

Trade Name:

Address: 220 OPERATION WAY

City: CAYCE State: SC ZIP: 29033

IMPORTANT: Round all dollar amounts to the nearest dollar.

A. Federal Employer Identification Number	57-0248695	G. NAICS code	221100
B. Federal taxable income	X 29736612	H. Enter the state abbreviation for location of the principal place of business.	SC
C. Federal income tax	0	I. Does the income of this corporation include the income of any disregarded entities?	Yes No X
D. Income tax apportionment percentage	0.02 %	J. Was the income of this corporation included in a consolidated federal income tax return?	Yes X No
E. Gross revenues	2998699530	K. If answered yes to J, enter FEIN of consolidated federal income tax return	57-0784499
F. Total assets	15019055753	L. Do the books of the corporation contain intercompany debt?	Yes X No

Computation of Income Tax - See instructions.		Computation of Franchise Tax - See instructions.	
1A. Louisiana net income before loss adjustments and federal income tax deduction	X 5725	5A. Total capital stock, surplus, & undivided profits	5338576131
1B. Subchapter S corporation exclusion	0	5B. Franchise tax apportionment percentage	0.02 %
1C. Loss carryforward [$ .00] less federal tax refund applicable to loss [$ .00] Attach schedule. Stmt 1	0	5C. Franchise taxable base	1067715
1C1. Loss carryforward utilized.	0	6. Amount of assessed value of real and personal property in Louisiana in 2016	0
1D. Federal income tax deduction Stmt 2	0	7. Louisiana franchise tax	2754
1D1. Federal Disaster Relief Credits	0	8. Nonrefundable franchise tax credits from Schedule NRC-P1	0
1E. Louisiana taxable income	X 5725	9. Franchise tax after priority 1 credits	2754
2. Louisiana income tax	0		
3. Nonrefundable income tax credits from Schedule NRC-P1	0		
4. Income tax after priority 1 credits	0		

IMPORTANT!
All three (3) pages of this return MUST be mailed in along with completed schedules. Please sign and date the return on Page 3 and remit any amount due shown on Line 26, Column 3. Do not send cash.

DEV ID 2395

FOR OFFICE USE ONLY

Field Flag

SPEC CODE

21741

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CIFT-620EXT-V (1/17) 2395

CE

LOUISIANA
DEPARTMENT of REVENUE

Corporation Tax
Electronically Filed Extension Payment Voucher

Louisiana Department of Revenue
P O Box 751
Baton Rouge, LA 70821-0751

SPEC CODE | | | | | This space at the bottom of the form is to be used only when specifically instructed by LDR Otherwise, leave blank

IMPORTANT NOTICE: The voucher below must accompany payments made by corporation tax filers that have filed their extension request electronically and are not required to submit their payments through electronic funds transfer An Electronic Funds Transfer payment is required if the payment exceeds $5,000

This voucher is NOT a request for an extension of time to file a return or an extension of time to pay the tax due You must still submit a separate extension request An extension will not be granted if a payment is made using this form Payments received after the return due date will be charged interest and late payment penalty

Do not claim portions of the payment with this form as estimated franchise tax on the return. All amounts remitted will be applied as estimated income tax and should be indicated as such on the return Overpayments of estimated income tax will automatically be applied toward fulfillment of any franchise tax liability

Corporation Income and Franchise Taxes Extension Payment				
1	Estimated amount of income and franchise taxes due	1	42,820.	00
2	Less all previously remitted estimated income and franchise tax payments	2	42,820.	00
3	Total estimated taxes due and remitted with this voucher - Subtract Line 2 from Line 1	3	NONE	.00

Mail this voucher with your payment to:
Louisiana Department of Revenue
P O Box 751
Baton Rouge, LA 70821-0751

Detach and submit the voucher below with your payment You MUST enter your LA Revenue Account Number below

2395

CIFT-620EXT-V (1/17) For calendar year ended 2016, or other tax year beginning ____________, 2016, ending ____________, 2017 **2016 CE**

Corporation Tax Electronically Filed Extension Payment Voucher

Name			Louisiana Revenue Account Number
SOUTH CAROLINA ELECTRIC and GAS COMPANY			5556337-001
Address			FEIN
220 OPERATION WAY			57-0248695
City	State	ZIP	Telephone
CAYCE	SC	29033-3701	803-217-9000

SPEC CODE | | | | |

DO NOT SEND CASH.

Amount enclosed ▶ NONE

1906

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CIFT-620-SD Page 2 of 3

LA Revenue Account Number: 5556337-001

Net Amount Due

	Col. 1 - Income tax	Col. 2 - Franchise tax	Col. 3 - Total
10. Tax liability after priority 1 credits	0	2754	
11. Louisiana Citizens Insurance Assessment Paid	0		
11A. Louisiana Citizens Insurance Credit	0		
11B. Refundable credits from Schedule RC-P2	0	0	
12. Total priority 2 credits	0	0	
13. Tax liability after priority 2 credits	0	2754	
14. Overpayment after priority 2 credits	0	0	
15. Nonrefundable credits from Schedule NRC-P3	0	0	
16. Tax liability after priority 3 credits	0	2754	2754
17A. Overpayment after priority 2 credits	0	0	
17B. Refundable credits from Schedule RC-P4	229497	0	
17C. Credit carryforward from prior year return	42820	0	
17D. Estimated payments	0		
17E. Payment made with extension	0	0	
17F. Total refundable credits and payments	272317	0	
18. Overpayment	272317	0	272317
19. Tax due	0	2754	
20. Amount of income tax overpayment applied to franchise tax		272317	
21. Net Tax due		0	
22. Interest	0	0	
23. Delinquent filing penalty	0	0	
24. Delinquent payment penalty	0	0	
25. Additional donation to The Military Family Assistance Fund	0	0	**PAY THIS AMOUNT**
26. Total amount due	0	0	0

IMPORTANT!

All three (3) pages of this return MUST be mailed in along with completed schedules. Please sign and date the return on Page 3 and remit any amount due shown on Line 26, Column 3. **Do not send cash.**

21742

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CIFT-620-SD (1/17) Page 3 of 3

LA Revenue Account Number: 5556337-001

Net Amount Due			
	Col. 1 - Income tax	Col. 2 - Franchise tax	Col. 3 - Total
27. Net overpayment		0	269563
28. Amount of overpayment you want to donate to The Military Family Assistance Fund			0
29. Amount of overpayment to be refunded			239563
30. Amount of overpayment to be credited to 2017			30000

Make payment to Louisiana Department of Revenue. DO NOT SEND CASH. You can pay your taxes online at: ***www.revenue.louisiana.gov/fileonline.***

Under the penalties of perjury, I declare that I have examined this return, including all accompanying documents, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which he has any knowledge.			
Signature of Officer		Signature of Preparer	
Enter Name of Officer JAMES E SWAN IV		Firm Name	
Title of Officer CONTROLLER		Telephone	Date (dd/mm/yyyy)
Telephone 803-217-9000	Date (dd/mm/yyyy) 10/11/2017		

Social Security Number, PTIN, or FEIN of Paid Preparer

IMPORTANT!

All three (3) pages of this return MUST be mailed in along with completed schedules. Please sign and date the return on Page 3 and remit any amount due shown on Line 26, Column 3. Do not send cash.

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CIFT-620-SD (1/17) Schedules NRC-P1 and RC-P4

LA Revenue Account Number: 5556337-001

Schedule NRC-P1 Nonrefundable Priority 1 Tax Credits			
Description	**Code**	**Corporation Income Tax (A)**	**Corporation Franchise Tax (B)**
1.			
2.			
3.			
4.			
5.			
6.			
7. Total Income Tax Credits: Add credit amounts in Column A, Line 1 through 6. Enter here and on CIFT-620, Line 3.		0.	
8. Total Franchise Tax Credits: Add credit amounts in Column B, Line 1 through 6. Enter here and on CIFT-620, Line 8.			0.

Description	Code
Premium Tax	100
Bone Marrow	120
Nonviolent Offenders	140

Description	Code
Qualified Playgrounds	150
Debt Issuance	155
Contributions to Educational Institutions	160

Description	Code
Donations to Public Schools	170
Donations of Materials, Equipment, Advisors, Instructors	175

Description	Code
Other	199

Schedule RC-P4 – Refundable Priority 4 Tax Credits			
Description	**Code**	**Corporation Income Tax (A)**	**Corporation Franchise Tax (B)**
1. Inventory Tax (50F)	50F	229497.	
2.			
3.			
4.			
5.			
6. Total Income Tax Credits: Add credit amounts in Column A, Lines 1 through 5. Enter the result here and on CIFT-620, Line 17B, Col. 1.		229497	
7. Total Franchise Tax Credits: Add credit amounts in Column B, Line 1 through 5. Enter here and on CIFT-620, Line 17B Col. 2.			0.

Description	Code
Inventory Tax	50F
Ad Valorem Natural Gas	51F

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CIFT-620-SD (1/17) Schedule NRC-P3

LA Revenue Account Number: 5556337-001

Schedule NRC-P3 Nonrefundable Priority 3 Tax Credits – Part I - Nonrefundable Tax Credits			
Description	**Code**	**Corporation Income Tax (A)**	**Corporation Franchise Tax (B)**
1.			
2.			
3.			
4.			
5.			
6.			

Description	Code	Description	Code	Description	Code	Description	Code
Atchafalaya Trace	200	New Jobs Credit	224	La Community Economic Dev	234	Biomed/University Research	300
Previously Unemployed	208	Refunds by Utilities	226	Apprenticeship	236	Tax Equalization	305
Recycling Credit	210	Eligible Re-entrants	228	Ports of Louisiana Investor	238	Manufacturing Establishments	310
Basic Skills Training	212	Neighborhood Assistance	230	Ports of Louisiana Import Export Cargo	240	Enterprise Zone	315
Inventory Tax	218	Research and Development	231			Other	399
Ad Valorem Natural Gas	219	Cane River Heritage Area	232	Other	299		

Schedule NRC-P3 – Part II - Transferable, Nonrefundable Tax Credits			
Description	**Code**	**Corporation Income Tax (A)**	**Corporation Franchise Tax (B)**
7.			
7A.			
8.			
8A.			
9.			
9A.			
10. Total Income Tax Credits: Add credit amounts in Column A, Line 1 through 9. Enter here and on CIFT-620, Line 15 Column 1.		0.	
11. Total Franchise Tax Credits: Add credit amounts in Column B, Line 1 through 9. Enter here and on CIFT-620, Line 15 Column 2.			0.

For further information about these credits, please see instructions beginning on page 26.

Description	Code	Description	Code	Description	Code	Description	Code
Motion Picture Investment	251	Digital Interactive Media	254	LCDFI Credit	258	Motion Picture Infrastructure	261
Research and Development	252	Motion Picture Resident	256	New Markets	259	Angel Investor	262
Historic Structures	253	Capital Company	257	Brownfields Investor	260		

21746

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CIFT-620-SD (1/17) Schedule RC-P2

LA Revenue Account Number: 5556337-001

Schedule RC-P2 Refundable Priority 2 Tax Credits - Part I - Refundable Tax Credits and Rebates			
Description	Code	Corporation Income Tax (A)	Corporation Franchise Tax (B)
1.			
2.			
3.			
4.			
5.			

Schedule RC-P2 - Part II - Transferable, Refundable Credits			
Description	Code	Corporation Income Tax (A)	Corporation Franchise Tax (B)
6. Musical and Theatrical Production	62F		
6A.			
7. Musical and Theatrical Production	62F		
7A.			
8. Musical and Theatrical Production	62F		
8A.			
9. Total Income Tax Credits: Add credit amounts in Column A, Lines 1 through 8. Enter the result here and on CIFT-620, Line 11B, Col. 1.		0.	
10. Total Franchise Tax Credits: Add credit amounts in Column B, Lines 1 through 5. Enter the result here and on CIFT-620, Line 11B, Col. 2.			0.

For further information about these credits, please see instructions beginning on page 28.

Description	Code
Ad Valorem Offshore Vessels	52F
Telephone Company Property	54F
Prison Industry Enhancement	55F
Urban Revitalization	56F
Mentor-Protege	57F
Milk Producers	58F
Technology Commercialization	59F
Angel Investor	61F
Musical and Theatrical Production	62F
School Readiness Child Care Provider	65F
School Readiness Business - Supported Child Care	67F
School Readiness Fees and Grants to Resource and Referral Agencies	68F
Retention and Modernization	70F
Conversion of Vehicle to Alternative Fuel	71F
Digital Interactive Media and Software	73F
Leased Solar Energy Systems	74F
Other Refundable	80F

21747

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CIFT-620-SD (1/17) Schedules 2016A and 2016B

LA Revenue Account Number: 5556337-001

All applicable schedules must be completed.

Schedule 2016A - Required Information

	Question	Answer		FEIN	Percentage
1.	At the end of the tax year, did you directly or indirectly own 50% or more of the voting stock of any corporation or an interest of any partnership, including any entity treated as a corporation or partnership? If yes, list the FEIN and percentage owned for the five largest percentages. Attach a schedule listing the names, addresses, FEIN and percentage owned of all entities.	Yes ☐ No ☒	1		
			2		
			3		
			4		
			5		
2.	At the end of the tax year, did any corporation, individual, partnership, trust, or association directly or indirectly own 50% or more of your voting stock? If yes, list the FEIN and percentage owned for the five largest percentages. Attach a schedule listing the names, addresses, FEIN and percentage owned of all entities.	Yes ☒ No ☐	1		
			2	Stmt 3	
			3		
			4		
			5		
3.	If you answered yes to Line I on CIFT 620, list the FEIN of five of those entities. Also, attach a schedule listing the names, addresses FEIN of all entities.	Yes ☐ No ☒	1		
			2		
			3		
			4		
			5		

Schedule 2016B - Computation of Income Tax Apportionment Percentage

Description of items used as ratios	1. Total amount	2. Louisiana amount	3. Percent
1. Net sales of merchandise and/or charges for services			
A. Sales	3,015,062,430.	NONE	
B. Charges for services			
C. Other gross apportionable income			
D. Total – Add the amounts in Columns 1 and 2.	3,015,062,430.	NONE	NONE %
2. For certain oil & gas businesses only. Wages, salaries, and other personal service compensation paid during the year. (See instructions.) Ratio not used. Check box. ☐	271,947,554.		%
3. For certain oil & gas businesses only. (See instructions.) Income tax property ratio – Enter percentage from Schedule 2016C, Line 24. Ratio not used. Check box. ☐			0.06 %
4. ONLY corporations primarily in the oil and gas business, enter ratio from Line 1D, Column 4 (See Instructions.)			NONE %
5. Total of percents in Column 3			0.06 %
6. Average of percents - Divide Line 5 by applicable number of ratios. Enter here and on CIFT-620, Line D.			0.02 %

21750

6D2122 1.000
CIFT-620-SD (1/17) Schedule 2016C

LA Revenue Account Number: 5556337-001

For Certain Oil & Gas Companies Only Schedule 2016C - Computation of Corporate Income Tax Property Ratio

	Located Everywhere		Located in Louisiana	
	1. Beginning of year	2. End of year	3. Beginning of year	4. End of year
Intangible Assets				
1. Cash	110,056,888.	112,818,510.		
2. Notes and accounts receivable	521,796,470.	514,133,020.		
3. Reserve for bad debts	(2,964,230.)	(3,239,931.)		
4. Investment in U.S. govt. obligations				
5. Stock and obligations of subsidiaries				
6. Other investments – Attach schedule Stmt 4	171,160,735.	180,487,957.		
7. Loans to stockholders				
8. Other intangible assets – Attach schedule Stmt 4	2289299325.	2627861715.		
9. Accumulated depreciation	( )	( )		
10. Total intangible assets – Add Lines 1 through 9	3089349188.	3432061271.		
Real and Tangible Assets				
11. Inventories	171,415,921.	172,900,770.	7,876,385.	5,996,153.
12. Bldgs. and other depreciable assets	14615659537.	15686426272.		
13. Accumulated depreciation	(4150427302.)	(4272332560.)	( )	( )
14. Depletable assets				
15. Accumulated depletion	( )	( )	( )	( )
16. Land				
17. Other real & tangible assets – Attach schedule				
18. Excessive reserves, assets not reflected on books, or undervalued assets				
19. Total real and tangible assets – Add Lines 11 through 18	10636648156.	11586994482.	7,876,385.	5,996,153.
20. Less real and tangible assets not used in production of net apportionable income – Attach schedule				
21. Balance - Subtract Line 20 from Line 19	10636648156.	11586994482.	7,876,385.	5,996,153.
22. Beginning of year balance		10636648156.		7,876,385.
23. Total – Add Lines 21 and 22.		22223642638.		13,872,538.
24. Income tax property ratio (Line 23, Column 4 ÷ Line 23, Column 2)				0.06 %

21751

6D2123 1.000
CIFT-620-SD (1/17) Schedule 2016D

LA Revenue Account Number: 5556337-001

Schedule 2016D - Computation of Louisiana Net Income

See instructions if separate accounting method is used and check box. ☐

	Totals			Totals	
1A. Gross receipts	2,998,699,530.	.00	22. Other employee benefit plans	43,614,763.	.00
1B. Less returns and allowances		.00	23. Other deductions - Attach schedule. Stmt 5	863,684,043.	.00
1C. Balance. Subtract Line 1B from Line 1A.	2,998,699,530.	.00	24. Total deductions - Add Lines 10 through 23.	2,167,587,335.	.00
2. Less: Cost of goods sold and/or operations - Attach schedule. Stmt 5	1,088,310,803.	.00	25. Net income from all sources - Subtract Line 24 from Line 9.	-28,623,353.	.00
3. Gross profit - Subtract Line 2 from Line 1C.	1,910,388,727.	.00	26. Allocable income from all sources:		
4. Gross rents	20,964,105.	.00	26A. Net rents and royalties from immovable or corporeal movable property		.00
5. Gross royalties		.00	26B. Royalties from the use of patents, trademarks, etc.		.00
6. Income from estates, trusts, partnerships		.00	26C. Income from estates, trusts, and partnerships		.00
7. Income from construction, repair, etc.		.00	26D. Income from construction, repair, etc.		.00
8. Other income - Attach schedule. Stmt 5	207,611,150.	.00	26E. Other allocable income		.00
9. Total income - Add Lines 3 through 8.	2,138,963,982.	.00	26F. Allocable expenses	( )	.00
10. Compensation of officers	15,144,833.	.00	26G. Total allocable income from all sources		.00
11. Salaries and wages (not deducted elsewhere)	55,188,382.	.00	27. Net income subject to apportionment - Subtract Line 26G from Line 25.	-28,623,353.	.00
12. Repairs	215,401,652.	.00	28. Net income apportioned to Louisiana	-5,725.	.00
13. Bad debts	6,349,958.	.00	29. Allocable income from Louisiana sources:		
14. Rent	6,587,833.	.00	29A. Net rents and royalties from immovable or corporeal movable property		.00
15. Taxes and licenses - Attach schedule. Stmt 5	230,655,590.	.00	29B. Royalties from the use of patents, trademarks, etc.		.00
16. Interest	297,298,406.	.00	29C. Income from estates, trusts, and partnerships		.00
17. Charitable Contributions	NONE	.00	29D. Income from construction, repair, etc.		.00
18. Depreciation - Attach schedule.	431,921,192.	.00	29E. Other allocable income		.00
19. Depletion - Attach schedule.		.00	29F. Allocable expenses	( )	.00
20. Advertising	371,874.	.00	29G. Total allocable income from Louisiana sources		.00
21. Pension, profit sharing, stock bonus, and annuity plans	1,368,809.	.00	30. Louisiana net income before loss adjustments and federal income tax deduction - Add Line 28 and Line 29G.	-5,725.	.00

21752

6D2124 1.000

CIFT-620-SD (1/17) Schedule 2016E and 2016F

LA Revenue Account Number: 5556337-001

Schedule 2016E - Reconciliation of Income Per Books with Income Per Return

1. Net income per books	512,691,484.	6. Total - Add Lines 1 through 5.	782,596,730.
2. Louisiana income tax		7. Income recorded on books this year, but not included in this return - Attach Schedule. Stmt 7	35,789,944.
3. Excess of capital loss over capital gains		8. Deductions in this tax return not charged against book income this year:	
4. Taxable income not recorded on books this year - Attached schedule Stmt 7	-25,961,383.	a. Depreciation	218,786,376.
5. Expenses recorded on books this year, but not deducted in this return:		b. Depletion	
a. Depreciation	4,228,547.	c. Other - Attach Schedule Stmt 8	555,020,472.
b. Depletion		9. Total - Add Lines 7 and 8.	809,596,792.
c. Other - Attached schedule. Stmt 7	291,638,082.	10. Net income from all sources per return - Subtract Line 9 from Line 6.	-27,000,062.

Schedule 2016F - Reconciliation of Federal and Louisiana Net Income

See R.S. 47:287.71, R.S. 47:287.73, and R.S. 47:287.82 for information.

	Column 1	Column 2
1. Enter the total net income calculated under federal law before special deductions.		-27,000,062.
2. Additions to federal net income:		
a. Louisiana income tax		
b. Related members interest\intangible\management fee expenses or costs. From Form R-6950 (see instructions).		
c. Other additions - Attach schedule.		41,912,433.
d. Total additions - Add Lines 2a through 2c.		41,912,433.
3. Subtractions from federal net income:		
a. Dividends		
b. Interest		
c. Road Home - The amount included in federal taxable income		
d. Louisiana depletion in excess of federal depletion		
e. Expenses not deducted on the federal return due to Internal Revenue Code Section 280C		
f. Exempt amount of related members interest\intangible\management fee expenses or costs. From Form R-6950 (see instructions).		
g. Other subtractions - Attach schedule.		43,535,724.
h. Total subtractions – Add Lines 3a through 3g.		43,535,724.
4. Louisiana net income from all sources - The amount should agree with Schedule 2016D, Line 25.		-28,623,353.

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CIFT-620-SD (1/17) Schedule 2016G

602115 1.000

LA Revenue Account Number: 5556337-001

All applicable schedules must be completed.

Schedule 2016G - Liabilities and Capital from Balance Sheet		
Liabilities and Capital	**1. Beginning of year**	**2. End of year**
1. Accounts payable	392,595,365.	198,630,173.
2. Mortgages, notes, and bonds payable one year old or less at balance sheet date and having a maturity of one year or less from original date incurred	303,880,566.	525,461,103.
3. Other current liabilities – Attach schedule. Stmt 9	714,065,721.	796,820,781.
4. Loans from stockholders – Attach schedule.		
5. Due to subsidiaries and affiliates		
6. Mortgages, notes, and bonds payable more than one year old at balance sheet date or having a maturity of more than one year from original date incurred	4,429,036,067.	4,929,015,843.
7. Other liabilities – Attach schedule. Stmt 9	2,863,381,719.	3,230,551,722.
8. Capital stock: a. Preferred stock	100,000.	100,000.
b. Common stock	576,405,122.	576,405,122.
9. Paid-in or capital surplus	2,183,832,337.	2,283,832,337.
10. Surplus reserves – Attach schedule.		
11. Earned surplus and undivided profits	2,262,700,447.	2,478,238,672.
12. Excessive reserves or undervalued assets		
13. Totals – Add Lines 1 through 12.	13,725,997,344.	15,019,055,753.

21754

6D2116 1.000
CIFT-620-SD (1/17) Schedule 2016G-1

LA Revenue Account Number: 5556337-001

See Revenue Ruling 06-010 and Revenue Information Bulletin 13-006.
All applicable schedules must be completed. Complete Lines 1 through 11 only if there is an end of year balance in the "Due to Subsidiaries and Affiliates" account or an **equivalent account** on the books of the corporation. All corporations must complete Lines 12 through 19.

Schedule 2016G-1 Computation of Franchise Tax Base	
1. Capital Stock:	
1A. Common Stock - Include paid-in or Capital Surplus	
1B. Preferred Stock - Include paid-in or Capital Surplus	
2. Total Capital stock - Add Lines 1A and 1B.	
3. Surplus and undivided profits	
4. Surplus reserves - Include any excessive reserves or undervalued assets.	
5. Total - Add Lines 2, 3, and 4.	
6. Due to subsidiaries and affiliates (Do not net with receivables)	
7. Deposit liabilities to affiliates - Included in the amount on Line 6	
8. Accounts payable less than 180 days old - Included in the amount on Line 6	
9. Adjusted debt to affiliates - Subtract Lines 7 and 8 from Line 6.	
10A. If Line 9 is greater than zero, AND Line 5 is greater than or equal to zero, subtract Line 5 from Line 9. If both conditions of this line do not apply, skip to Line 10B.	
10B. If Line 9 is greater than zero, AND Line 5 is less than or equal to zero, subtract Line 5 from Line 9. Multiply the difference by 50 percent and enter the result here.	
11. Additional Surplus and Undivided Profits - See instructions.	
Total Franchise Taxable Base	
12. Capital Stock: Common Stock	576,405,122.
Preferred Stock	100,000.
13. Paid-in or capital surplus - Include items of paid-in capital in excess of par value.	2,283,832,337.
14. Surplus reserves - Attach schedule.	
15. Earned surplus and undivided profits	2,478,238,672.
16. Excessive reserves or undervalued assets	
17. Additional surplus and undivided profits - From Line 11 above.	
18. Allowable deductions - See instructions.	
19. **Total capital, surplus and undivided profits - Add Lines 12 through 18. Also enter the total on CIFT-620, Line 5A. Round to the nearest dollar.**	5,338,576,131.

Note: All accounts on the books of the corporation should be reviewed to determine if an account is an item of capital, surplus or undivided profits. All items of capital, surplus and undivided profits must be included in the franchise taxable base. See Revenue Information Bulletin 06-026.

21755

6D2127 1.000
CIFT-620-SD (1/17) Schedule 2016H

LA Revenue Account Number: 5556337-001

Schedule 2016H - Computation of Corporate Franchise Tax Property Ratio		
	LOCATED EVERYWHERE	LOCATED IN LOUISIANA
	1. End of year	2. End of year
1. Cash	112,818,510.	
2. Notes and accounts receivable	514,133,020.	
3. Reserve for bad debts	(3,239,931)	( )
4. Investment in U.S. govt. obligations		
5. Stock and obligations of subsidiaries		
6. Other investments – Attach schedule Stmt 10	180,487,957.	
7. Loans to stockholders		
8. Other intangible assets – Attach schedule Stmt 10	2627861715.	
9. Accumulated depreciation	( )	( )
10. Total intangible assets – Add Lines 1-9	3432061271.	
11. Inventories	172,900,770.	5,996,153.
12. Bldgs. and other depreciable assets	15686426272.	
13. Accumulated depreciation	(4272332560)	( )
14. Depletable assets		
15. Accumulated depletion	( )	( )
16. Land		
17. Other real & tangible assets – Attach schedule		
18. Excessive reserves, assets not reflected on books, or undervalued assets		
19. Total real and tangible assets – Add Lines 11 through 18	11586994482.	5,996,153.
20. Total Assets – Add Lines 10 and 19	15019055753.	5,996,153.
21. Franchise tax property ratio (Line 20, Column 2 ÷ Line 20, Column 1)		0.04 %

21756

6D2128 1.000
CIFT-620-SD (1/17) Schedule 2016I

LA Revenue Account Number: 5556337-001

Schedule 2016I - Computation of Corporate Franchise Tax Apportionment Percentage			
Description of items used as ratios	1. Total amount	2. Louisiana amount	3. Percent
1. Net sales of merchandise, charges for services, and other revenues			
A. Sales	3,015,062,429.		
B. Charges for services			
C. Other Revenues:			
(i) Rents and royalties			
(ii) Dividends and interest from subsidiaries			
(iii) Other dividends and interest			
(iv) All other revenues			
D. Total - If the ratio is not used, check the box. ☐	3,015,062,429.		NONE %
2. Franchise tax property ratio - Enter the percentage from Schedule 2016H, Line 21. If the ratio is not used, check the box. ☐			0.04 %
3. Total of applicable percents in Column 3			0.04 %
4. Average of percents – Divide Line 3 by applicable number of ratios. Enter here and on CIFT-620, Line 5B.			0.02 %

6D2129 1.000

CIFT-620-SD (1/17) Schedules 2016J, 2016K, and 2016L

LA Revenue Account Number: 5556337-001

Schedule 2016J - Calculation of Income Tax			
1. Enter the amount of net taxable income from CIFT-620, Line 1E.			-5,725.
2. Calculation of tax	Column 1 Net Income in each bracket	RATE	Column 2 TAX
a. First $25,000 of net taxable income		x 4% =	
b. Next $25,000		x 5% =	
c. Next $50,000		x 6% =	
d. Next $100,000		x 7% =	
e. Over $200,000		x 8% =	
3. Add the amounts in Column 1, Lines 2a through 2e and enter the result.			
4. Add the amounts in Column 2, Lines 2a through 2e. Round to the nearest dollar. Enter the result in Column 2 and on CIFT-620, Line 2.			NONE

Schedule 2016K - Summary of Estimated Tax Payments			
	Check number	Date	Amount
1. Credit from prior year return			42,820.
2. First quarter estimated payment			
3. Second quarter estimated payment			
4. Third quarter estimated payment			
5. Fourth quarter estimated payment			
6. Payment made with extension request			NONE

Schedule 2016L - Calculation of Franchise Tax	
1. Enter the amount from CIFT-620, Line 5C or Line 6, whichever is greater.	1,067,715.
2. Enter the amount of Line 1 or $300,000, whichever is less.	300,000.
3. Muliply the amount on Line 2 by $1.50 for each $1,000 or major fraction and enter the result.	450.
4. Subtract Line 2 from Line 1 and enter the result.	767,715.
5. Multiply the amount on Line 4 by $3.00 for each $1,000 or major fraction and enter the result.	2,304.
6. Add Lines 3 and 5. Round to the nearest dollar. Enter the result here and on CIFT-620, Line 7.	2,754.

21758

6D2130 1.000

CIFT-620-SD (1/17) Schedules 2016M and 2016N

LA Revenue Account Number: 5556337-001

Schedule 2016M - Analysis of Schedule 2016G, Line 11, Column 2 - Earned surplus and undivided profits per books			
1. Balance at beginning of year	2,262,700,447.	b. Stock	
2. Net Income per books	512,691,484.	c. Property	
3. Other increases - Attach schedule. Stmt 11	3.	6. Other decreases - Attach schedule.	
4. Total - Add Lines 1, 2, and 3.	2,775,391,934.	7. Total - Add Lines 5 and 6.	296,950,000.
5. Distributions: a. Cash	296,950,000.	8. Balance at end of year - Subtract Line 7 from Line 4.	2,478,441,934.

Schedule 2016N - Additional Information Required

1. Describe the nature of your business activity and specify your principal product or service, both in Louisiana and elsewhere.

Louisiana:

STORAGE OF NATURAL GAS

Elsewhere:

ELECTRIC & GAS UTILITY

2. Indicate the date and state of incorporation. 07/19/1924 SC

3. Indicate parishes in which property is located.

Bienville

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Louisiana Form 620, Page 1 Detail

Line 1c - NOL Carryover

Carryover generated in tax year 2016	5,725.
Total NOL carried forward to 2017	5,725.

Louisiana Form 620, Page 1 Detail

Line 1d - Federal Income Tax Deduction

LA net income	-5,725.
LA net income before federal income tax deduction	-5,725.
Federal net income	-29,736,612.
Ratio of LA net income to federal net income	0.0193
Federal income tax liability	NONE
Federal income tax	NONE
Federal income tax attributable to LA income	NONE

Louisiana Form 620, Page 7 Detail

Schedule A Question 2

Name	SCANA CORPORATION
EIN/SSN	570784499
Percentage owned	100.00

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Louisiana Form 620, Page 8 Detail

Line 6 - Other Investments	Beginning	Ending
INVEST IN ASSOC COMPANIES		2,856,381.
OTHER INVESTMENTS	171,160,735.	177,631,576.
Total	171,160,735.	180,487,957.

Line 8 - Other Intg. Assets	Beginning	Ending
ACCOUNTS RECEIVABLE- ASSOC COMPANY	13,994,351.	4,731,796.
INTEREST AND DIVIDENDS RECEIVABLE		121,727.
OTHER CURRENT ASSETS	10,356,905.	
PREPAYMENTS	81,880,379.	86,351,520.
ACC DEFERRED INCOME TAXES	277,332,298.	354,286,724.
CLEARING ACCOUNTS	4,232.	418,919.
DUE FROM AFFIL DIRECTORS ENDOWMENT	382,447.	379,524.
MISC DEFERRED DEBITS	82,102,622.	163,564,671.
PRELIM SURVEY AND INVEST CHGS	198,470.	322,402.
REGULATORY ASSET - FASB 109	1,775,528,967.	1,967,097,185.
UNAMORTIZED DEBT EXPENSE	31,259,888.	35,470,866.
UNAMORTIZED LOSS ON REACQ DEBT	16,258,766.	15,116,381.
Total	2,289,299,325.	2,627,861,715.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Louisiana Form 620, Page 9 Detail

Sch D, Line 2 - Cost of Goods Sold

Inventory at beginning of year	171,415,921.
Merchandise bought for manufacture or sale	5,268,408.
Cost of Labor	-420,319.
Other costs	1,084,947,563.
Subtotal lines 1 through 5	1,261,211,573.
Less inventory at end of year	172,900,770.
Cost of goods sold before adjustments	1,088,310,803.
Total	1,088,310,803.

Sch D, Line 8 - Other income

Net gains from sale of capital assets	NONE
Net gains (loss) from sale of property	-38,024,208.
GAIN ON LAND SALES	
INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	-4,833,278.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	15,066,925.
Total	-27,790,561.

Sch D, Line 15 - Taxes

TAXES AND LICENSES	230,655,590.
Total taxes deducted on the federal return	230,655,590.
Total	230,655,590.

Sch D, Line 23 - Other Deductions

Amortization	8,116,771.
Travel, meals and entertainment	1,001,437.
POLLUTION CONTROL	10,705,348.
INJURIES AND DAMAGES	5,807,027.
INSURANCE	7,158,823.
MERCHANDISING EXPENSES	1,031,448.
MISCELLANEOUS DEDUCTIONS	39,340,430.

Continued on next page Statement 5

Louisiana Form 620, Page 9 Detail

Sch D, Line 23 - Other Deductions (Cont'd)

MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	51,659,518.
OFFICE SUPPLIES AND EXPENSES	20,537,993.
OUTSIDE SERVICES	16,406,895.
PIPELINE INTEGRITY	-17,084,713.
481A ADJUSTMENT	-4,228,547.
RESEARCH AND DEVELOPMENT	721,608,322.
STATE ADJUSTMENTS	1,623,291.
Total	863,684,043.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Louisiana Form 620, Page 10 Detail

Sch E, Line 4 - Taxable Income not Recorded on Books

Gain/loss on Disposition of Assets	267,022.
BA_N02_EMIS_ALLOW	-146,028.
E_BOOK_CAP_INT_EQUITY	-26,082,377.
Total	-25,961,383.

Sch E, Line 5c - Other Expenses on Books Not Deducted

State Taxes	-529,600.
Contribution carryover	2,736,550.
Bad debts	-44,400.
Federal income tax	209,229,479.
Travel and entertainment disallowed	1,001,437.
AB_NUCL_PLANT_REF	15,580,797.
AS_ENVIRO_CLEAN	798,991.
AY_LTD	-601,447.
BI_PREPAIDS	1,113,959.
BT_PSHIP_TAX_BRANDON	19,696.
CH_INTEREST_INCOME_AMEND_RTNS	32,629.
BV_REG_ASSET_CANADYS_U2-3	9,122,722.
G_INJURIES	2,504,441.
I_DEF_FUEL	31,549,990.
K_MAJOR_MAINTENANCE	-5,521,170.
P_REAQ_DEBT	1,142,385.
T_REG_ASSET_CUST	335,103.
U_PENSION	19,604,703.
X_VCS	183,816.
Y_REG_ASSET_RECOV_CAP	296,000.
CC_NET_METER	1,757,750.
CD_PSHIP_TAX_SRFI	63,862.
CG_JAD_TERMINATION	1,200,000.
GR_ALT_FUEL_CREDIT_ADDBACK	60,389.
Total	291,638,082.

Sch E, Line 7 - Income Recorded on Books Not Included in Return

Gain/loss on disposition of assets	38,912,666.
AG_CIAC	-17,084,713.
BB_S02_EMIS_ALLOW	-8,862.
BX_REG_ASSET_NND_CARRYING	13,970,853.
Total	35,789,944.

Statement 7

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Louisiana Form 620, Page 10 Detail

Sch E, Ln 8c - Other Ded not Charged Against Book Income

State taxes	-31,515,978.
Bad debts	-320,101.
Amortization	8,116,771.
AH_VACATION	521,110.
AI_GRANTS	400,000.
AK_LINE_PACK	-1,683.
AM_CPI	-202,222,083.
AO_POLLUTION	-1,344,598.
AP_FUKISHIMA	427,884.
AQ_BONUS	-2,011,086.
AT_STORM_DAMAGE	23,607,305.
AU_OPEB_TEMP	-3,073,318.
AV_ELEC_SIDE_MGT	-519,610.
AW_RESEARCH	721,608,322.
AX_LOBBYING	-218,753.
AY_LTD	-19,207.
BF_OFFICER_COMP	-2,505,282.
BH_PSHIP_TAX_CANADYS	519,819.
BI_PREPAIDS	2,331,717.
BJ_REG_ASSET_ENVIRON	-94,783.
BM_DIRENDOW_PERM	-28,544.
BM_DIRENDOW_TEMP	-128,484.
BR_GAS_WNA_CAP	1,811,353.
BU_PSHIP_TAX_LOUISA	4,737.
CJ_PSHIP_TAX_BRUNNER_ISLAND	906,042.
CI_REG_ASSET_PILOT_MODEL_ACCT_ORDER	1,682,475.
CA_REG_ASSET_MCMEEKIN	1,005,199.
E _BOOK_CAP_INT_DEBT	16,522,358.
F_UNICAP	222,266.
GL_DEF_PIPE_INTEG	2,233,149.
H_AUTO_DEPR	-2,445,692.
I _DEF_FUEL	7,232,654.
N_REG_ASSET_DEF_CAP	6,238,082.
Q _KEY_EMP_TEMP	1,748,575.
R _NUC_DECOM_TEMP	-3,224,920.
S_ERIP	235,528.
W_CONT_NONCASH	2,177.
CF_CYBER_SECURITY	7,317,071.
Total	555,020,472.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Louisiana Form 620, Page 11 Detail - Sch 2016G

Line 3 - Other Current Liabilities	Beginning	Ending
ACCRUED INTEREST PAYABLE	64,981,071.	66,073,421.
ACCRUED TAXES PAY - FEDERAL INCOME	139,536,235.	176,366,709.
ACCRUED TAXES PAY - STATE INCOME	31,166,055.	76,470,800.
ACCRUED TAXES PAYABLE - OTHER	173,595,618.	190,023,235.
ACCTS PAYABLE - ASSOC COS	71,894,901.	61,294,130.
CUSTOMER DEPOSITS	57,087,060.	60,283,425.
DIVIDENDS DECLARED	72,300,000.	77,500,000.
MISC CURRENT AND ACCRUED LIABILITIE	94,969,814.	80,313,106.
TAXES PAYABLE - OTHER	1,882,026.	1,970,592.
TAXES PAYABLE - SALES AND USE	6,652,941.	6,525,363.
Total	714,065,721.	796,820,781.

Line 7 - Other Liabilities		
ACC DEF FED INCOME TAX	1,692,572,092.	1,883,853,155.
ACC DEF STATE INCOME TAX	217,942,117.	241,044,075.
ACCUM DEF INVEST TAX CREDITS	23,580,500.	22,188,300.
DEFERRED CREDITS - OTHER	73,571,854.	49,074,144.
DUE TO AFFILIATES	212,184,657.	257,285,183.
FASB 109 REGULATORY LIABILITY	147,243,710.	238,854,458.
INJURIES AND DAMAGES RESERVE	5,355,089.	7,859,531.
OBLIGATIONS UNDER CAP LEASE	12,477,819.	20,678,011.
OTHER ASSET RETIREMENT OBLIGATIONS	476,223,696.	509,434,012.
UNAMORT DISCT - LT DEBT	2,230,185.	280,853.
Total	2,863,381,719.	3,230,551,722.

Louisiana Form 620, Page 13 Detail-Sch H

Line 6 - Other Investments Everywhere	Ending
INVEST IN ASSOC COMPANIES	2,856,381.
OTHER INVESTMENTS	177,631,576.
Total	180,487,957.

Line 8 - Other Intg. Assets Everywhere	
ACCOUNTS RECEIVABLE- ASSOC COMPANY	4,731,796.
INTEREST AND DIVIDENDS RECEIVABLE	121,727.
OTHER CURRENT ASSETS	
PREPAYMENTS	86,351,520.
ACC DEFERRED INCOME TAXES	354,286,724.
CLEARING ACCOUNTS	418,919.
DUE FROM AFFIL DIRECTORS ENDOWMENT	379,524.
MISC DEFERRED DEBITS	163,564,671.
PRELIM SURVEY AND INVEST CHGS	322,402.
REGULATORY ASSET - FASB 109	1,967,097,185.
UNAMORTIZED DEBT EXPENSE	35,470,866.
UNAMORTIZED LOSS ON REACQ DEBT	15,116,381.
Total	2,627,861,715.

Louisiana Form 620, Page 16 Detail

Sch M, Line 3 - Other Increases

Other Increases	3.
Total	3.

Electronic Filing Information: PDF attachments Included in this Return

Tax Year: 2016
Name: SOUTH CAROLINA ELE
Return No: C0000ZR6

Jurisdiction: Louisiana
No of Attachments: 1

PDF Attachment Description	PDF File Name	File Size
SCEG_2016_LA_attachment_R-10610_as filed	C0000ZR6_LA_SCEG_2016_LA_attachment_R-10610_as filed.pdf	45,313

10/11/2017 15:25:17

R -10610 (1/17)

LOUISIANA
DEPARTMENT of REVENUE

Schedule of Ad Valorem Tax Credit Claimed by Manufacturers, Distributors and Retailers for Ad Valorem Tax Paid on Inventory or Natural Gas

Louisiana Revised Statute 47:6006

IMPORTANT: Use this form if filing a 2016 tax return. See instructions.

PLEASE PRINT OR TYPE.

Taxpayer Name
SOUTH CAROLINA ELECTRIC AND GAS

LDR Account ID
5556337-001

Filing Period
01/01/16 - 12/31/16

Parish Name of Louisiana Parish that issued the assessment	Assessment Number	Total Assessment	Inventory Assessment Qualified Inventory held by manufacturers, suppliers or retailers	Ratio Inventory Assessment/ Total Assessment *Use only if using ratio method to determine eligible tax credit **	Total Assessed Tax Paid	Qualified Inventory Tax Credit Claimed on Current Year Return List actual tax paid or apply ratio method to determine eligible tax credit	Check Number	Check Date	Check Amount
BIENVILLE	8010000327	1,036,640	1,036,640		117,389	117,389	2586509	12/01/16	117,389
BIENVILLE	8010000327	1,053,150	1,053,150		112,108	112,108	2407862	01/19/16	112,108

** See RIB 06-036 for instructions and additional information.*

R -10610 (1/17)

LOUISIANA
DEPARTMENT *of* REVENUE

Schedule of Ad Valorem Tax Credit Claimed by Manufacturers, Distributors and Retailers for Ad Valorem Tax Paid on Inventory or Natural Gas

Louisiana Revised Statute 47:6006

IMPORTANT: Use this form if filing a 2016 tax return. See instructions.

PLEASE PRINT OR TYPE.

Taxpayer Name SOUTH CAROLINA ELECTRIC AND GAS	
SSN/LDR Account ID 5556337-001	Filing Period 01/01/16 - 12/31/16

Check the box for the credit type this worksheet is used to calculate: ■ Inventory Tax Credit (50F) ☐ Ad Valorem Natural Gas Credit (51F)

	See instructions to complete Lines 1 through 14 below.	Total Column	Column 1	Column 2	Column 3	Column 4	Column 5
			7449440001	5556337001			
1	Industrial Tax Exemption program (ITEP) related ad valorem taxes						
2	New business limitation						
3A	Amount of ad valorem taxes paid	347,765	118,268	229,497			
3B	Amount of ad valorem taxes paid qualifying for the credit	347,765	118,268	229,497			
4	If Line 3 of the Total Column is less than or equal to $500,000, see instructions. Otherwise, go to Line 5.						
5	Adjusted Louisiana Income Tax						
6	Inventory Tax Credit - *See instructions.*						
7	Tax Liability before applying the Inventory Tax Credit or Ad Valorem Natural Gas Credit						
8	Amount of the credit exceeding tax liability						
9	Enter the amount from Line 8, Total Column, or $1,000,000, whichever is less.						
10	Multiply Line 9 by 75 percent. This is the refundable portion of your credit for all taxpayers.						
11	Divide Line 10 by Line 8. This is the ratio of the excess credit that is refundable.						
12	Refundable credit amount per taxpayer						
13	Amount of credit to report on return						
14	Credit carry forward amount per taxpayer						

FORMS (TAX)

FORM NUMBER

STATE 1120

JURISDICTION

MARYLAND

MONTH	YEAR
	2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

MARYLAND FORM **EL101B** **INCOME TAX DECLARATION FOR BUSINESSES ELECTRONIC FILING**

16101B004

2016

OR FISCAL YEAR BEGINNING 0101 2016, ENDING 12312016

DO NOT MAIL

SOUTH CAROLINA ELECTRIC and GA
Name of corporation or pass-through entity

570248695
Federal Employer Identification Number

Street Address	City or town	State	ZIP code	+4
220 OPERATION WAY	CAYCE	SC	29033	-370

PART I Tax Return Information (whole dollars only)

1. Amount of overpayment to be applied to 2017 estimated tax (Corporations only.) 1. 86.00
2. Amount of overpayment to be refunded (Corporations only.). . . . . REFUND 2. .00
3. Total amount due . . . . 3. .00

PART II Declaration and Signature Authorization

Check appropriate box to consent to: ☐ Direct Deposit of refund or ☐ Electronic Funds Withdrawal (direct debit)

4a. Type of account:
☐ Checking ☐ Savings

4b. Routing Number (9-digits): ______ 4c. Account number: ______

4d. Direct debit settlement date (Enter the date (MMDDYY) you want the payment withdrawn from the account.) . . . . 4d. ______

4e. Direct debit amount . . . . 4e. ______

☐ I consent that the corporation's refund be directly deposited as designated above and declare that the information shown is correct. By consenting, I also agree to disclose to the Maryland State Treasurer's Office certain income tax information including name, amount of refund and the above bank information. This disclosure is necessary to effect direct deposit.

☐ I authorize the State of Maryland and its designated financial agent to initiate an electronic funds withdrawal payment entry to the financial institution account indicated for payment of the Maryland taxes owed by the corporation or pass-through entity and the financial institution to debit the entry to this account. Upon confirmation of consent during the filing of the corporation or pass-through entity state return, this authorization is to remain in full force and effect, and I may not terminate the authorization. I also authorize the financial institutions involved in the processing of this electronic payment of taxes to receive confidential information necessary to answer inquiries and resolve issues related to the payment.

☐ I do not want direct deposit of the refund or an electronic funds withdrawal (direct debit) of the balance due.

Under penalties of perjury, I declare that I am an officer, general partner or managing member of the above corporation or of the pass-through entity. I have compared the information contained on my electronic return with the information that I provided to my electronic return originator or entered on-line and that the name(s), address and amounts described above agree with the amounts shown on the corresponding lines of my 2016 Maryland electronic income tax return. To the best of my knowledge and belief, the return is true, correct and complete. I consent that the return, including accompanying schedules and statements, be sent to the Maryland Revenue Administration Division by my electronic return originator or by the electronic return software provider.

Sign Here ______ Corporate officer, general partner or managing member's signature | CONTROLLER Title | 10/11/2017 Date

Wait ten (10) days *after* the receipt of a valid acknowledgement before calling 1-800-638-2937 or from Central Maryland 410-260-7980, about the refund.

PART III Declaration of Electronic Return Originator (paid preparer)

I declare that I have reviewed the return of the corporation or pass-through entity and that the entries on this form are complete and correct to the best of my knowledge. I have obtained the signature of the corporate officer, general partner or managing member, before submitting the return to the Maryland Revenue Administration Division, have provided that official with a copy of all forms and information to be filed with the Maryland Revenue Administration Division, and have followed all other requirements described in the Maryland Business E-File Handbook. This declaration is to be retained at the site of the electronic return originator.

Electronic Return Originator Use Only

Originator's Signature ______ Date ______ | Firm's name (or yours if self-employed) ______

571767
EFIN | Address ______ ZIP code ______

Telephone Number ______

MARYLAND FORM **500E**

APPLICATION FOR EXTENSION TO FILE CORPORATION INCOME TAX RETURN

16500E004

2016

OR FISCAL YEAR BEGINNING 0101 2016, ENDING 12312016

570248695
Federal Employer Identification Number (9 digits)

Print Using Blue or Black Ink Only

SOUTH CAROLINA ELECTRIC and GAS COM
Name

220 OPERATION WAY
Street Address

CAYCE — City or town
SC — State
29033 — ZIP code
3701 — +4

For Office Use Only

ME	YE	EC	EC

STOP IF NO TAX IS DUE WITH THIS EXTENSION, DO NOT MAIL THIS PAPER FORM, INSTEAD FILE THE EXTENSION AT: www.marylandtaxes.com OR CALL 410-260-7829 FROM CENTRAL MARYLAND OR 1-800-260-3664 FROM ELSEWHERE TO TELEFILE THIS FORM

TAX PAYMENT WORKSHEET INSTRUCTIONS

Line 1 - **Tax liability** Enter the total amount of income tax the corporation is expected to owe Use Form 500 as a worksheet

Line 2 - **Estimated tax payments** Enter the total amount of Maryland estimated tax paid with Form 500D for the tax year Include any overpayment from the prior period that was credited to the current tax year

Line 3 - **Allowable tax credits** Enter the allowable tax credits from Form 500CR or 502S or tax paid on the corporation's behalf by a pass-through entity

Line 4 - **Total payments and credits** Add lines 2 and 3 and enter the total on line 4

Line 5 - Tax due Subtract line 4 from line 1 and enter the result on line 5 This is the tax to be paid with the application for extension

TAX PAYMENT WORKSHEET

1.	Tax liability expected for the current tax year	1	NONE
2.	Estimated tax payments and amount credited from the prior period	2	93.
3.	Allowable tax credits	3	.
4	Total payments and credits Add lines 2 and 3 and enter here	4	93.
5.	Tax due - Subtract line 4 from line 1	5	.

TAX PAID WITH THIS EXTENSION ► $ NONE.
(If filing and paying electronically, do not mail this form)

IF NO TAX IS DUE WITH THIS EXTENSION, DO NOT MAIL THIS PAPER FORM UNLESS IT IS THE FIRST FILING OF THE ENTITY, INSTEAD FILE THE EXTENSION AT: www.marylandtaxes.com OR CALL 410-260-7829 FROM CENTRAL MARYLAND OR 1-800-260-3664 FROM ELSEWHERE TO TELEFILE THIS FORM.

Make checks payable to and mail to:
Comptroller Of Maryland
Revenue Administration Division
110 Carroll Street
Annapolis, Maryland 21411-0001

(Write Your Federal Employer Identification Number On Check Using Blue Or Black Ink.)

MARYLAND FORM **500**

CORPORATION INCOME TAX RETURN

2016

165000004

OR FISCAL YEAR BEGINNING 0101 2016, ENDING 12312016

570248695
Federal Employer Identification Number (9 digits)

FEIN Applied for Date (MMDDYY)

071924
Date of Organization or Incorporation (MMDDYY)

221100
Business Activity Code No. (6 digits)

SOUTH CAROLINA ELECTRIC and GAS COM
Name

220 OPERATION WAY
Current Mailing Address Line 1 (Street No. and Street Name or PO Box)

Current Mailing Address Line 2 (Apt No., Suite No., Floor No.)

CAYCE — City or Town | SC — State | 29033 — ZIP code | 3701 — +4 | ME | YE

Print Using Blue or Black Ink Only

STAPLE CHECK HERE

CHECK HERE IF:
- [ ] Name or address has changed
- [ ] First filing of the corporation
- [ ] This tax year's beginning and ending dates are different from last year's due to an acquisition or consolidation.
- [ ] Inactive corporation
- [ ] Final Return

SEE CORPORATION INSTRUCTIONS. ATTACH A COPY OF THE FEDERAL INCOME TAX RETURN THROUGH SCHEDULE M2.

1a. Federal Taxable Income (Enter amount from Federal Form 1120 line 28 or Form 1120-C line 25.) See Instructions. Check applicable box:
[X] 1120 [ ] 1120-REIT [ ] 990T
[ ] Other: ________ IF 1120S, FILE ON FORM 510 . . . . . 1a. -27000062.

1b. Special Deductions (Federal Form 1120 line 29b or Form 1120-C line 26b.) . . . . . 1b. ______

1c. Federal Taxable Income before net operating loss deduction (Subtract line 1b from 1a) . . . . . ▶ 1c. -27000062.

MARYLAND ADJUSTMENTS TO FEDERAL TAXABLE INCOME
(All entries must be positive amounts.)

ADDITION ADJUSTMENTS

2a. Section 10-306.1 related party transactions . . . . . ▶ 2a. ______
2b. Decoupling Modification Addition adjustment (Enter code letter(s) from instructions.) . . . . . __ __ __ __ ▶ 2b. ______
2c. Total Maryland Addition Adjustments to Federal Taxable Income (Add lines 2a and 2b) . . . . . 2c. ______

SUBTRACTION ADJUSTMENTS

3a. Section 10-306.1 related party transactions . . . . . ▶ 3a. ______
3b Dividends for domestic corporation claiming foreign tax credits (Federal form 1120/1120C Schedule C line 15) . . . . . ▶ 3b. ______
3c. Dividends from related foreign corporations (Federal form 1120/1120C Schedule C line 13 and 14) . . . . . ▶ 3c. ______
3d. Decoupling Modification Subtraction adjustment (Enter code letter(s) from instructions.) . . . . . __ __ __ __ ▶ 3d. ______
3e Total Maryland Subtraction Adjustments to Federal Taxable Income (Add lines 3a through 3d.) . . . . . 3e. ______

4. Maryland Adjusted Federal Taxable Income before NOL deduction is applied (Add lines 1c and 2c, and subtract line 3e) . . . . . 4. -27000062.

5 Enter Adjusted Federal NOL Carry-forward available from previous tax years (including FDSC Carry-forward) on a separate company basis (Enter NOL as a positive amount.) . . . . . ▶ 5. ______

MARYLAND FORM **500** | **CORPORATION INCOME TAX RETURN** | 165000104 | **2016** page 2

NAME SOUTH CAROLINA EL FEIN 570248695

6.	**Maryland Adjusted Federal Taxable Income** (If line 4 is less than or equal to zero, enter amount from line 4.) (If line 4 is greater than zero, subtract line 5 from line 4 and enter result. If result is less than zero, enter zero.) . . . 6.		-27000062 .
	MARYLAND ADDITION MODIFICATIONS (All entries must be positive amounts.)		
7a.	State and local income tax . . . ▶ 7a.	.	
7b.	Dividends and interest from another state, local or federal tax exempt obligation . . . ▶ 7b.	.	
7c.	Net operating loss modification recapture (Do not enter NOL carryover. See instructions.) . . . ▶ 7c.	.	
7d.	Domestic Production Activities Deduction . . . ▶ 7d.	.	
7e.	Deduction for Dividends paid by captive REIT . . . ▶ 7e.	.	
7f.	Other additions (Enter code letter(s) from instructions and attach schedule). . . Stmt 1 . . . G ▶ 7f.	473833623 .	
7g.	Total Addition Modifications (Add lines 7a through 7f.) . . . 7g.		473833623 .
	MARYLAND SUBTRACTION MODIFICATIONS (All entries must be positive amounts.)		
8a.	Income from US Obligations . . . ▶ 8a.	.	
8b.	Other Subtractions (Enter code letter(s) from Stmt 1 instructions and attach schedule) . . . M ▶ 8b.	365981990 .	
8c.	Total Subtraction Modifications (Add lines 8a and 8b.) . . . 8c.		365981990 .
	NET MARYLAND MODIFICATIONS		
9.	Total Maryland Modifications (Subtract line 8c from 7g. If less than zero, enter negative amount.) . . . 9.		107851633 .
10.	Maryland Modified Income (Add lines 6 and 9.) . . . 10.		80851571 .
	APPORTIONMENT OF INCOME (To be completed by multistate corporations whose apportionment factor is less than 1, otherwise skip to line 13.)		
11.	Maryland apportionment factor (from page 4 of this form) (If factor is zero, enter .000001.) . . . ▶ 11.		
12.	Maryland apportionment income (Multiply line 10 by line 11.) . . . 12.		.
13.	Maryland taxable income (from line 10 or line 12, whichever is applicable.) . . . 13.		81 .
14.	Tax (Multiply line 13 by 8.25%.) . . . 14.		7 .
15a.	Estimated tax paid with Form 500D, Form MW506NRS and/or credited from 2015 overpayment . . . ▶ 15a.	93 .	
15b.	Tax paid with an extension request (Form 500E) . . . ▶ 15b.	.	
15c.	Nonrefundable business income tax credits from Part Y. (See instructions for Form 500CR.)	You must file this form electronically to claim business tax credits from Form 500CR.	
15d.	Refundable business income tax credits from Part BB. (See instructions for Form 500CR.)		
15e.	The Heritage Structure Rehabilitation Tax Credit is claimed on line 1 of Part BB on Form 500CR. Check here ☐ if you are a non-profit corporation.		
15f.	Nonresident tax paid on behalf of the corporation by pass-through entities (Attach Maryland Schedule K-1.) . . . ▶ 15f.	.	
15g.	Total payments and credits (Add lines 15a through 15f.) . . . 15g.		93 .
16.	Balance of tax due (If line 14 exceeds line 15g, enter the difference.) . . . ▶ 16.		.
17.	Overpayment (If line 15g exceeds line 14, enter the difference.) . . . ▶ 17.		86 .
18.	Interest and/or penalty from Form 500UP ______ or late payment interest ______ . . . TOTAL ▶ 18.		.
19.	Total balance due (Add lines 16 and 18, or if line 18 exceeds line 17 enter the difference.) 19.		.
20.	Amount of overpayment to be applied to estimated tax for 2017 (not to exceed the net of line 17 less line 18) . . . ▶ 20.		86 .
21.	Amount of overpayment TO BE REFUNDED (Add lines 18 and 20, and subtract the total from line 17.) . . . ▶ 21.		.

COM/RAD-001
6D2312 4.000

MARYLAND FORM **500** — **CORPORATION INCOME TAX RETURN** — 165000204 — **2016** page 3

NAME SOUTH CAROLINA EL FEIN 570248695

DIRECT DEPOSIT OF REFUND (See Instructions.) **Be sure the account information is correct.**
If this refund will go to an account outside of the United States, then to comply with banking rules, place a "Y" in this box ▶☐ and see Instructions.
For the direct deposit option, complete the following information clearly and legibly.

22a. Type of account: ▶ ☐ Checking ☐ Savings

22b. Routing Number (9-digits): ▶ __________

22c. Account number: ▶ __________

INFORMATIONAL PURPOSES ONLY (LINES 23 & 24)

23. NOL generated in Current Year - Carryforward 20 years and back 2 years (If line 6 is less than zero, enter on line 23.) . . . . . 23. -27000062.__

24. NAM generated in Current Year - Carried Forward/Back with Loss on Line 23 per Section 10-205(e) (If line 6 is less than zero AND line 9 is greater than zero, enter the amount from line 9 on line 24.) . . . . . 24. 107851633.__

MARYLAND FORM **500** **CORPORATION INCOME TAX RETURN** 165000304 **2016** page 4

NAME SOUTH CAROLINA EL FEIN 570248695

Schedule A - COMPUTATION OF APPORTIONMENT FACTOR (Applies only to multistate corporations. See instructions.)

NOTE: Special apportionment formulas are required for rental/leasing, financial institutions, transportation and manufacturing companies.	Column 1 TOTALS WITHIN MARYLAND	Column 2 TOTALS WITHIN AND WITHOUT MARYLAND	Column 3 DECIMAL FACTOR (Column 1 ÷ Column 2 rounded to six places)
1A. Receipts a. Gross receipts or sales less returns and allowances			
b. Dividends			
c. Interest			
d. Gross rents			
e. Gross royalties			
f. Capital gain net income			
g. Other income (Attach schedule.)			
h. Total receipts (Add lines 1A(a) through 1A(g), for Columns 1 and 2.)			
1B. Receipts Enter the same factor shown on line 1A, Column 3. Disregard this line if special apportionment formula is used			
2. Property a. Inventory			
b. Machinery and equipment			
c. Buildings			
d. Land			
e. Other tangible assets (Attach schedule.)			
f. Rent expense capitalized (multiply by eight)			
g. Total property (Add lines 2a through 2f, for Columns 1 and 2)			
3. Payroll a. Compensation of officers			
b. Other salaries and wages			
c. Total payroll (Add lines 3a and 3b, for Columns 1 and 2.)			

4. Total of factors (Add entries in Column 3.)

5. Maryland apportionment factor Divide line 4 by four for three-factor formula, or by the number of factors used if special apportionment formula required. (If factor is zero, enter .000001 on line 11 page 2.)

COM/RAD-001

6D2323 2.000
0000ZR M16C 10/11/2017 15:02:24 V16-7.1F 57-0248695 8

MARYLAND FORM **500** | **CORPORATION INCOME TAX RETURN** | 165000404 | **2016** page 5

NAME SOUTH CAROLINA EL FEIN 570248695

SCHEDULE B - ADDITIONAL INFORMATION REQUIRED (Attach a separate schedule if more space is necessary.)

1. Telephone number of corporation tax department: 8032179000
2. Address of principal place of business in Maryland (if other than indicated on page 1):
220 OPERATION WAY CAYCE SC 29033
3. Brief description of operations in Maryland: NA
4. Has the Internal Revenue Service made adjustments (for a tax year in which a Maryland return was required) that were not previously reported to the Maryland Revenue Administration Division? ☐ Yes ☒ No
If "yes", indicate tax year(s) here: ____________ and submit an amended return(s) together with a copy of the IRS adjustment report(s) under separate cover.
5. Did the corporation file employer withholding tax returns/forms with the Maryland Revenue Administration Division for the last calendar year? ☐ Yes ☒ No
6. Is this entity part of the federal consolidated filing? ► ☒ Yes ☐ No
If a multistate operation, provide the following:
7. Is this entity a multistate corporation that is a member of a unitary group? ► ☒ Yes ☐ No
8. Is this entity a multistate manufacturer with more than 25 employees? ► ☐ Yes ☒ No

SIGNATURE AND VERIFICATION

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements and to the best of my knowledge and belief it is true, correct and complete. If prepared by a person other than taxpayer, the declaration is based on all information of which the preparer has any knowledge.

Check here ☐ if you authorize your preparer to discuss this return with us.

[signature] 10112017
Officer's Signature Date

JAMES E SWAN IV
CONTROLLER
Officer's Name and Title

Preparer's Signature

Preparer's name, address and telephone number

►
Preparer's PTIN (required by law)

Make checks payable to and mail to:

Comptroller Of Maryland
Revenue Administration Division
110 Carroll Street
Annapolis, Maryland 21411-0001
(Write Your FEIN On Check Using Blue Or Black Ink.)

COM/RAD-001 6D2324 1.000

► ___ ___ ___
CODE NUMBERS (3 digits per line)

Maryland Form 500 Page 2 Detail

Line 7F - Other Additions

G. Amount required to nullify the impact of federal tax changes	473,833,623.
Total	473,833,623.

Line 8b - Other Subtractions

M. Amount required to nullify the impact of federal tax changes	365,981,990.
Total	365,981,990.

FORMS (TAX)

FORM NUMBER

STATE 1120

JURISDICTION

MISSISSIPPI

MONTH

YEAR

2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

Form 83-115-16-3-1-115 Rev. (05/16)

MS8453-C

Mississippi
Corporate Income Declaration for Electronic Filing
2016

Tax Year Beginning 01012016 | Tax Year Ending 12312016

DO NOT MAIL THIS DOCUMENT TO THE DEPARTMENT OF REVENUE

FEIN 570248695

SOUTH CAROLINA ELECTRIC and GAS COMPANY
Legal Name and DBA

Address	City	State	Zip +4	County Code
220 OPERATION WAY	CAYCE	SC	29033-3701	83

PART I: TAX RETURN INFORMATION (ROUND TO THE NEAREST DOLLAR)

1 Mississippi taxable income (Form 83-105, line 5 or Form 83-391, line 1)	1	
2 Total income tax (Form 83-105, line 6 or Form 83-391, line 2)	2	
3 Total payments & credits (Form 83-105, line 7 and line 12 or Form 83-391, line 3, 4 and 8)	3	40629
4 Amount you owe (Form 83-105, line 18 or Form 83-391, line 14)	4	
5 Overpayment (Form 83-105, line 19 or Form 83-391, line 15)	5	27941
6 Refund (Form 83-105, line 21 or Form 83-391, line 17)	6	
7 Amount of payment remitted electronically	7	

* If the corporation is filing a balance due return and the Department of Revenue does not receive full and timely payment of its tax liability, the corporation will be liable for the tax liability and all applicable interest and penalties.

PART II: DECLARATION OF OFFICER

Under the penalties of perjury, I declare that I am an officer of the above corporation and that the information I have given my electronic return originator (ERO), transmitter, and/or intermediate service provider (ISP) and the amounts in Part I above agree with the amounts on the corresponding lines of the corporation's Mississippi Corporate Income & Franchise Tax Return. To the best of my knowledge and belief, the corporation's return is true, correct and complete. I consent to my ERO, transmitter, and/or ISP sending the corporation's return, this declaration, and accompanying schedules and statements to the Department of Revenue (DOR). I also consent to the DOR my ERO, transmitter, and/or ISP an acknowledgement of receipt of transmission and an indication of whether or not the corporation's return is accepted, and, if rejected, the reason(s) for the rejection. This declaration is to be maintained by the ERO and provided to DOR on request.

Sign Here | Signature of Officer | Date 10/11/2017 | Title CONTROLLER

PART III: DECLARATION OF ELECTRONIC RETURN ORIGINATOR (ERO) AND PAID PREPARER

I declare that I have reviewed the above corporation's return and that the entries on Form MS8453-C are complete and correct to the best of my knowledge. If I am only a collector, I am not responsible for reviewing the return and only declare that this form accurately reflects the data on the return. The corporate officer will have signed this form before I submit the return. I will give the officer a copy of all forms and information to be filed with the Department of Revenue (DOR), and have followed all other requirements in Pub. 3112, IRS e-file Application and Participation and Pub. 4163, Modernized e-File (MeF) Information for Authorized IRS e-file Providers. If I am also the Paid Preparer, under penalties of perjury, I declare that I have examined the above corporation's return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct and complete. This Paid Preparer declaration is based on all information of which I have any knowledge.

ERO Use Only	ERO Signature	Date	Check if Also Paid Preparer	Check if Self-Employed	ERO SSN or PTIN
	Firm Name (or yours if self-employed), address and ZIP code			EIN	
				Phone No.	

Under penalties of perjury, I declare that I have examined the above taxpayer's return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete. This declaration is based on all information of which I have any knowledge.

Paid Preparer Use Only	Preparer Signature	Date	Check if Also Paid Preparer	Check if Self-Employed	Preparer SSN or PTIN
	Firm Name (or yours if self-employed), address and ZIP code			EIN	
				Phone No.	

6D2705 2.000

DO NOT Mail this Document to the Mississippi Department of Revenue

0000ZR M16C 10/11/2017 15:18:11 V16-7.1F 57-0248695 35

Form 83-105-16-3-1-115 (Rev. 05/16)

831051631115

Mississippi
Corporate Income and Franchise Tax Return
2016

Tax Year Beginning 01012016 Tax Year Ending 12312016

FEIN 570248695 Mississippi Secretary of State ID 919296

Legal Name and DBA	CHECK ALL THAT APPLY	CHECK ONE
SOUTH CAROLINA ELECTRIC and GAS COMPANY		
Address: 220 OPERATION WAY	Amended Return	100% Mississippi
City: CAYCE State: SC Zip +4: 29033-3701	Final Return	X Multistate Apportioning
County Code 83 NAICS Code 221100	Non Profit	Multistate Direct Accounting

FRANCHISE TAX **(ROUND TO THE NEAREST DOLLAR)**

1	Taxable capital (from Form 83-110, line 18)	1	5075000
2	Franchise tax (minimum tax $25) Fee-In-Lieu	2	12688
3	Franchise tax credit (from Form 83-401, line 1)	3	0
4	Net franchise tax due (line 2 minus line 3)	4	12688

INCOME TAX

Combined income tax return (enter FEIN of reporting corporation)

5	Mississippi net taxable income (from Form 83-122, line 30 or Form 83-310, line 5, column C)	5	0
6	Income tax	6	0
7	Income tax credits (from Form 83-401, line 3 or Form 83-310, line 5, column B)	7	0
8	Net income tax due (line 6 minus line 7)	8	0

PAYMENTS AND TAX DUE

9	Total franchise and Income tax (line 4 plus line 8)	9	12688
10	Overpayments from prior year	10	40629
11	Estimated tax payments and payment with extension	11	0
12	Total payments (line 10 plus line 11)	12	40629
13	Net total franchise and Income tax (line 9 minus line 12)	13	0
14	Interest and penalty on underestimated Income tax payments (from Form 83-305, line 19)	14	0
15	Late payment interest	15	0
16	Late payment penalty	16	0

Form **7004**
(Rev. December 2016)
Department of the Treasury
Internal Revenue Service

Application for Automatic Extension of Time To File Certain Business Income Tax, Information, and Other Returns

▶ File a separate application for each return.
▶ Information about Form 7004 and its separate instructions is at www.irs.gov/form7004.

OMB No. 1545-0233

Print or Type

Name: SCANA CORPORATION
Identifying number: 57-0784499
Number, street, and room or suite no. (If P.O. box, see instructions.): 220 OPERATION WAY
City, town, state, and ZIP code (If a foreign address, enter city, province or state, and country (follow the country's practice for entering postal code)).: CAYCE, SC 29033-3701

Note: File request for extension by the due date of the return for which the extension is granted. See instructions before completing this form.

Part I Automatic Extension for C Corporations With Tax Years Ending December 31. See instructions.

1a Enter the form code for the return listed below that this application is for 1 2

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part II Automatic Extension for Certain Estates and Trusts. See instructions.

b Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1041 (estate other than a bankruptcy estate)	04	Form 1041 (trust)	05

Part III Automatic Extension for Entities Not Using Part I, II, or IV. See instructions.

c Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 706-GS(D)	01	Form 1120-ND (section 4951 taxes)	20
Form 706-GS(T)	02	Form 1120-PC	21
Form 1041 (bankruptcy estate only)	03	Form 1120-POL	22
Form 1041-N	06	Form 1120-REIT	23
Form 1041-QFT	07	Form 1120-RIC	24
Form 1042	08	Form 1120S	25
Form 1065	09	Form 1120-SF	26
Form 1065-B	10	Form 3520-A	27
Form 1066	11	Form 8612	28
Form 1120	12	Form 8613	29
Form 1120-C	34	Form 8725	30
Form 1120-F	15	Form 8804	31
Form 1120-FSC	16	Form 8831	32
Form 1120-H	17	Form 8876	33
Form 1120-L	18	Form 8924	35
Form 1120-ND	19	Form 8928	36

Part IV Automatic Extension for C Corporations With Tax Years Ending June 30. See instructions.

d Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Form 7004 (Rev. 12-2016) Page 2

Part V **All Filers Must Complete This Part**

2 If the organization is a foreign corporation that does not have an office or place of business in the United States, check here . . . ▶ ☐

3 If the organization is a corporation and is the common parent of a group that intends to file a consolidated return, check here . . . ▶ ☒

If checked, attach a statement listing the name, address, and Employer Identification Number (EIN) for each member covered by this application.

4 If the organization is a corporation or partnership that qualifies under Regulations section 1.6081-5, check here . . ▶ ☐

5a The application is for calendar year 20 16 , or tax year beginning ________, 20 ___, and ending ________, 20 ___

b Short tax year. If this tax year is less than 12 months, check the reason: ☐ Initial return ☐ Final return ☐ Change in accounting period ☐ Consolidated return to be filed ☐ Other (see instructions - attach explanation)

6	Tentative total tax . . .	6	6,000,000.
7	Total payments and credits (see instructions) . . .	7	6,000,000.
8	Balance due. Subtract line 7 from line 6 (see instructions) . . .	8	

Form 7004 (Rev. 12-2016)

Form 7004 - Affiliated Group Members

Name	Employer ID	Name	Employer ID
SCANA SERVICES INC	57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695
SOUTH CAROLINA FUEL CO INC	57-0691209	SC GENERATING COMPANY INC	57-0784498
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908	SCANA ENERGY MARKETING INC	57-0850977
SERVICECARE INC	57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	56-2128483
CLEAN ENERGY ENTERPRISES INC	56-1078443	PSNC BLUE RIDGE CORPORATION	56-1791764
PSNC CARDINAL PIPELINE COMPANY	56-1955423	SCANA CORPORATE SECURITY SERVICES INC	20-0989017

Statement 1

Form 83-105-16-3-2-115 (Rev. 05/16)

831051632115

Mississippi
Corporate Income and Franchise Tax Return
2016

Page 2

FEIN 570248695

17	Late filing penalty (minimum income tax penalty $100)	17	0
18	**Total balance due** (if line 9 is larger than line 12, add line 13 through line 17)	18	0
19	**Total overpayment** (if line 12 is larger than line 9, subtract line 9 from line 12)	19	27941
20	**Overpayment credited to next year** (from line 19)	20	27941
21	**Overpayment to be refunded** (line 19 minus line 20)	21	0

See instructions for electronic payment options or attach payment voucher, Form 83-300, with check or money order for balance due.

PART I: CORPORATE INFORMATION

1 Is this a publicly traded corporation? Yes If yes, under what symbol? X No

2 If final return, enter reason and date effective: Date

3 If the corporation has been sold or merged, complete the following: Name, address and FEIN of the new existing corporation:

FEIN

4 If amended return, check reason. Mississippi Correction Federal Correction Other

5 Check if the company has been audited by the IRS. If the company has been audited, what year(s) are involved?

6 Principal business activity in Mississippi UTILITY 6a County location in Mississippi

7 Principal product or service in Mississippi STORAGE OF NATURAL GAS

8 Contact person for this return JAMES SWAN IV 8a Location and Phone number 803-217-9000

PART II: CORPORATE OFFICER INFORMATION

List the owners, officers, directors or partners who have a responsibility in the fiscal management of the organization.

Stmt 1

OFFICER NAME AND TITLE	SSN	ADDRESS	OWNERSHIP PERCENTAGE
G T DEVLIN,	111111111	220 OPERATION WAY, CAYCE, SC 29	
K R JACKSON, SRVP	111111112	220 OPERATION WAY, CAYCE, SC 29	
R M SENN, SRVP	111111113	220 OPERATION WAY, CAYCE, SC 29	
J B ARCHIE, SRVP	111111114	220 OPERATION WAY, CAYCE, SC 29	
W J TURNER III, V.P.	111111115	220 OPERATION WAY, CAYCE, SC 29	
T D GATLIN, V.P.	111111116	220 OPERATION WAY, CAYCE, SC 29	

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Form 83-105-16-3-3-115 (Rev. 05/16)

831051633115

FEIN 570248695

Mississippi
Corporate Income and Franchise Tax Return
2016

PART III: CORPORATE AFFILIATION SCHEDULE

List all entities owned by and affiliated with the corporation. See page 4 for supplemental schedule if needed.

ENTITY NAME	FEIN	ADDRESS	ENTITY TYPE

Check box if return may be discussed with preparer

I declare, under penalties of perjury, that I have examined this return and accompanying schedules and statements, and to the best of my knowledge and belief, this is a true, correct and complete return. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

CONTROLLER 10/11/2017 803-217-9000

Officer Signature and Title | Date | Business Phone

Paid Preparer Signature | Date | Paid Preparer Address

Paid Preparer PTIN | Paid Preparer Phone | City | State | Zip Code

6D2731 1.000

Mail Return To: Department of Revenue P.O. Box 23191 Jackson, MS 39225-3191

Form 83-110-16-3-1-115 (Rev. 05/16)

831101631115

Mississippi
Corporate Franchise Tax Schedule
2016

FEIN 570248695

CAPITAL BASE		(ROUND TO THE NEAREST DOLLAR)
1 Capital stock	1	576505122
2 Paid in capital	2	2283832337
3 Surplus and retained earnings	3	2481211937
4 Loans from shareholders or affiliates	4	0
5 Deferred taxes, contingent liabilities, all true reserves, and other elements (attach schedule)	5	2442873663
6 Less treasury stock	6	0
7 Holding company exclusion (attach schedule)	7	0
8 Total capital base (add line 1 through line 7)	8	7784423059

APPORTIONMENT RATIO		A MISSISSIPPI		B EVERYWHERE
9 Real & tangible personal property owned at year end (net book value)	9A	5074551	9B	11554184730
10 Gross receipts	10A	0	10B	3015062430
11 Total (line 9 plus line 10)	11A	5074551	11B	14569247160
12 Mississippi ratio (line 11A divided by line 11B)			12	0.0348
13 Taxable capital apportioned to Mississippi (line 8 multiplied by line 12. If 100% Mississippi, enter amount from line 8)			13	2708979

ASSESSED VALUE OF MISSISSIPPI PROPERTY

Mississippi County	Mississippi Assessed Value of Real Property	Mississippi Assessed Value of Personal Property
Monroe		5074551

TAXABLE CAPITAL		
14 Total assessed value of Mississippi property (attach additional schedule if needed)	14	5074551
15 Taxable capital (enter the larger of line 13 or line 14)	15	5074551
16 Prorate (except for initial return; if period is less than twelve months, multiply line 15 by the number of months covered by the return and divide by twelve)	16	0
17 Capital exemption (attach schedule)	17	0
18 Final taxable capital (line 15 or line 16 minus line 17. Round amount up to the next highest $1,000 and enter amount on Form 83-105, line 1. If negative, enter zero on Form 83-105, line 1)	18	5075000

6D2712 1.000

Form 83-120-16-3-1-115 (Rev. 05/16)

Mississippi Balance Sheet Per Books

FEIN 570248695

SCHEDULE L - BALANCE SHEETS PER BOOKS	Beginning of Tax Year		End of Tax Year	
ASSETS	(A) Amount	(B) Total	(C) Amount	(D) Total
1 Cash		110056888		112818510
2a Trade notes and accounts receivable	521796470		514133020	
b Less allowance for bad debts	(2964230)	518832240	(3239931)	510893089
3 Inventories		171415921		172900770
4 U.S. government obligations		0		0
5 Tax-exempt securities (see instructions)		0		0
6 Other current assets (attach statement) Stmt. 4.		106231635		91205043
7 Loans to shareholders		0		0
8 Mortgage and real estate loans		0		0
9 Other investments (attach statement) Stmt. 4.		171160735		180487957
10a Buildings and other depreciable assets	14615659537		15686426272	
b Less accumulated depreciation	(4150427302)	10465232235	(4272332560)	11414093712
11a Depletable assets	0		0	
b Less accumulated depletion	(0)	0	(0)	0
12 Land (net of any amortization)		0		0
13a Intangible assets (amortizable only)	0		0	
b Less accumulated amortization	(0)	0	(0)	0
14 Other assets (attach statement) Stmt. 4.		2183067690		2536656672
15 Total assets		13725997344		15019055753
LIABILITIES AND SHAREHOLDERS' EQUITY				
16 Accounts payable		392595365		198630173
17 Mortgages, notes, bonds payable in less than 1 year		303880566		525461103
18 Other current liabilities (attach statement) Stmt. 4.		714065721		796820781
19 Loans from shareholders		0		0
20 Mortgages, notes, bonds payable in 1 year or more		4429036067		4929015843
21 Other liabilities (attach statement) Stmt. 5.		2863381719		3230551722
22 Capital stock: a Preferred stock	100000		100000	
b Common Stock	576405122	576505122	576405122	576505122
23 Additional paid-in capital		2183832337		2283832337
24 Retained earnings - Appropriated (attach statement)		0		0
25 Retained earnings - Unappropriated		2265470450		2481211937
26 Adjustments to shareholders' equity (attach statement) Stmt 5		-2770003		-2973265
27 Less cost of treasury stock		(0)		(0)
28 Total liabilities and shareholders' equity		13725997344		15019055753

SCHEDULE M-1, RECONCILIATION OF INCOME (LOSS) PER BOOKS WITH FEDERAL INCOME PER RETURN

Note: Schedule M-3 required instead of schedule M-1 if total assets are $10 million or more - see instructions.

1 Net income (loss) per books	512691484	7 Income recorded on books this year not included on this return (itemize): tax-exempt interest $ 0	
2 Federal income tax per books	209229479	35789944	
3 Excess of capital losses over capital gains	0		35789944
4 Income subject to tax not recorded on books this year (itemize):	-25961383	8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $238786376	
a Depreciation $ 4228547		b Charitable contributions $ 0	
b Charitable contributions $ 2736550			
c Travel and entertainment $ 1001437			773806848
	86637150	9 Add lines 7 and 8	809596792
6 Add lines 1 through 5	782596730	10 Income (page 1, line 28) line 6 less line 9	-27000062

SCHEDULE M-2, ANALYSIS OF UNAPPROPRIATED RETAINED EARNINGS PER BOOKS

1 Balance at beginning of year	2265470450	5 Distributions: a Cash	296950000
2 Net income (loss) per books	512691484	b Stock	0
3 Other increases (itemize): Stmt 6		c Property	0
		6 Other decreases (itemize):	0
	3	7 Add lines 5 and 6	296950000
4 Add lines 1, 2 and 3	2778161937	8 Balance at end of year (line 4 less line 7)	2481211937

Form 83-122-16-3-1-115 (Rev. 05/16)

831221631115

Mississippi
Net Taxable Income Schedule
2016

Page 1

FEIN 570248695

COMPUTATION OF MISSISSIPPI NET TAXABLE INCOME			(ROUND TO THE NEAREST DOLLAR)
1 Federal taxable income (loss) before net operating loss deductions and special deductions (from federal Form 1120, page 1, line 28. If multistate direct accounting, enter zero and skip to line 23)	1		-27000062
STATE ADDITIONS TO FEDERAL TAXABLE INCOME			
2 State, local or foreign government taxes based on income	2		0
3 Interest on obligations of other states or political subdivisions (net of expenses)	3		0
4 Depletion expense in excess of cost	4		0
5 Federal capital loss carryover deduction	5		0
6 Federal special depreciation allowance	6		431921189
7 Other additions required by law (attach schedule)	7	Stmt 7	41912434
8 **Total additions** (add line 2 through line 7)	8		473833623
STATE DEDUCTIONS FROM FEDERAL TAXABLE INCOME			
9 Interest on obligations of the United States (net of expenses)	9		0
10 Wages reduced on federal return for federal employment tax credits	10		0
11 Income (loss) from partnership, S corporation or trust	11		0
12 Income (loss) from construction contracting or production of natural mineral resource products (net of expenses)	12		0
13 Additional depreciation due to a difference in the depreciable base for federal and state purposes (attach schedule)	13		322446266
14 Other deductions (attach schedule)	14	Stmt 7	46272274
15 **Total deductions** (add line 9 through line 14)	15		368718540
APPORTIONMENT / ALLOCATION (MULTISTATE ONLY)			
If 100% Mississippi, complete line 16 then skip to page 2, line 20			
16 **Adjusted federal income (loss)** (line 1 plus line 8 minus line 15)	16		78115021
17 Adjustment for nonbusiness income (loss) net of expenses (from Form 83-150, column E, line 2)	17		
18 Apportionable business income (loss) (line 16 minus line 17)	18		78115021
19 Apportionment ratio (enter ratio and check box as shown on Form 83-125, part II)	19		

X Sales retail

Manufacturers (retail)

Manufacturers (wholesale), Financial institutions, Pipelines (for pharmaceutical suppliers, see instructions)

Special Formula

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Form 83-122-16-3-2-115 (Rev. 05/16)

831221632115

Mississippi
Net Taxable Income Schedule
2016

FEIN 570248695

APPORTIONMENT / ALLOCATION

20 Mississippi apportioned income (loss)(if 100% Mississippi, enter line 16, otherwise, multiply line 18 by line 19)	20	0
21 Nonbusiness income (loss) allocated to Mississippi (from Form 83-150, column F, line 2)	21	0
22 Mississippi income (loss) from partnership, S corporation or trust (attach Mississippi K-1's, Form 84-132)	22	0
23 Mississippi income (loss) from construction contracting or production of natural mineral resource products (from Form 83-124, page 2, line 31 and/or page 3, line 46)	23	0
24 Adjustments related to Mississippi tax credits claimed	24	0
25 Mississippi capital loss carryover/carryback deduction (from Form 83-155, part II, line 2)	25	0
26 Other adjustments (attach schedule)	26	0

MISSISSIPPI TAXABLE INCOME

27 Income (loss) apportioned and allocated to Mississippi (add line 20 through line 26)	27	0
28 Mississippi net operating loss deduction (from Form 83-155, part I, line 2)	28	0
29 Income exemption (attach schedule; if not applicable enter zero)	29	0
30 **Mississippi net taxable income (loss)** (line 27 minus line 28 and line 29. Enter on Form 83-105, line 5; If filing combined, enter income (loss) on Form 83-310. If negative, enter zero on Form 83-105, line 5)	30	0

Form **4562** Department of the Treasury Internal Revenue Service (99)

Depreciation and Amortization

(Including Information on Listed Property)

▶ Attach to your tax return.

▶ Information about Form 4562 and its separate instructions is at *www.irs.gov/form4562.*

OMB No. 1545-0172

2016

Attachment Sequence No. 179

Name(s) shown on return: SOUTH CAROLINA ELECTRIC and GAS COMPANY

Identifying number: 57-0248695

Business or activity to which this form relates: General Depreciation & Amortization

Part I — Election To Expense Certain Property Under Section 179

Note: If you have any listed property, complete Part V before you complete Part I.

1	Maximum amount (see instructions)	1	
2	Total cost of section 179 property placed in service (see instructions)	2	
3	Threshold cost of section 179 property before reduction in limitation (see instructions)	3	
4	Reduction in limitation. Subtract line 3 from line 2. If zero or less, enter -0-	4	
5	Dollar limitation for tax year. Subtract line 4 from line 1. If zero or less, enter -0-. If married filing separately, see instructions	5	

6	(a) Description of property	(b) Cost (business use only)	(c) Elected cost

7	Listed property. Enter the amount from line 29	7	
8	Total elected cost of section 179 property. Add amounts in column (c), lines 6 and 7	8	
9	Tentative deduction. Enter the smaller of line 5 or line 8	9	
10	Carryover of disallowed deduction from line 13 of your 2015 Form 4562	10	
11	Business income limitation. Enter the smaller of business income (not less than zero) or line 5 (see instructions)	11	
12	Section 179 expense deduction. Add lines 9 and 10, but don't enter more than line 11	12	
13	Carryover of disallowed deduction to 2017. Add lines 9 and 10, less line 12 ▶	13	

Note: Don't use Part II or Part III below for listed property. Instead, use Part V.

Part II — Special Depreciation Allowance and Other Depreciation (Don't include listed property.) (See instructions.)

14	Special depreciation allowance for qualified property (other than listed property) placed in service during the tax year (see instructions)	14	196,749,764.
15	Property subject to section 168(f)(1) election	15	
16	Other depreciation (including ACRS)	16	2,285,905.

Part III — MACRS Depreciation (Don't include listed property.) (See instructions.)

Section A

17	MACRS deductions for assets placed in service in tax years beginning before 2016	17	223,119,828.
18	If you are electing to group any assets placed in service during the tax year into one or more general asset accounts, check here ▶ ☐		

Section B - Assets Placed in Service During 2016 Tax Year Using the General Depreciation System

(a) Classification of property	(b) Month and year placed in service	(c) Basis for depreciation (business/investment use only - see instructions)	(d) Recovery period	(e) Convention	(f) Method	(g) Depreciation deduction
19a 3-year property						
b 5-year property		3,065,007.	5.000	HY	200 DB	613,002.
c 7-year property		12,294,620.	7.000	HY	200 DB	1,756,409.
d 10-year property						
e 15-year property		74,629,229.	15.000	HY	150 DB	3,731,461.
f 20-year property		97,653,218.	20.000	HY	150 DB	3,662,527.
g 25-year property			25 yrs.		S/L	
h Residential rental property			27.5 yrs.	MM	S/L	
			27.5 yrs.	MM	S/L	
i Nonresidential real property		179,129.	39 yrs.	MM	S/L	2,296.
				MM	S/L	

Section C - Assets Placed in Service During 2016 Tax Year Using the Alternative Depreciation System

(a) Classification of property	(b)	(c)	(d)	(e)	(f)	(g)
20a Class life					S/L	
b 12-year			12 yrs.		S/L	
c 40-year			40 yrs.	MM	S/L	

Part IV — Summary (See instructions.)

21	Listed property. Enter amount from line 28	21	
22	**Total.** Add amounts from line 12, lines 14 through 17, lines 19 and 20 in column (g), and line 21. Enter here and on the appropriate lines of your return. Partnerships and S corporations - see instructions	22	431,921,192.
23	For assets shown above and placed in service during the current year, enter the portion of the basis attributable to section 263A costs	23	

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695
Form 4562 (2016) Page 2

Part V **Listed Property** (Include automobiles, certain other vehicles, certain aircraft, certain computers, and property used for entertainment, recreation, or amusement.)

Note: For any vehicle for which you are using the standard mileage rate or deducting lease expense, complete **only** 24a, 24b, columns (a) through (c) of Section A, all of Section B, and Section C if applicable.

Section A - Depreciation and Other Information (Caution: See the instructions for limits for passenger automobiles.)

24a Do you have evidence to support the business/investment use claimed? Yes No 24b If "Yes," is the evidence written? Yes No

(a) Type of property (list vehicles first)	(b) Date placed in service	(c) Business/ investment use percentage	(d) Cost or other basis	(e) Basis for depreciation (business/investment use only)	(f) Recovery period	(g) Method/ Convention	(h) Depreciation deduction	(i) Elected section 179 cost
25 Special depreciation allowance for qualified listed property placed in service during the tax year and used more than 50% in a qualified business use (see instructions)						25		
26 Property used more than 50% in a qualified business use:								
		%						
		%						
		%						
27 Property used 50% or less in a qualified business use:								
		%				S/L -		
		%				S/L -		
		%				S/L -		
28 Add amounts in column (h), lines 25 through 27. Enter here and on line 21, page 1						28		
29 Add amounts in column (i), line 26. Enter here and on line 7, page 1							29	

Section B - Information on Use of Vehicles

Complete this section for vehicles used by a sole proprietor, partner, or other "more than 5% owner," or related person. If you provided vehicles to your employees, first answer the questions in Section C to see if you meet an exception to completing this section for those vehicles.

	(a) Vehicle 1		(b) Vehicle 2		(c) Vehicle 3		(d) Vehicle 4		(e) Vehicle 5		(f) Vehicle 6	
30 Total business/investment miles driven during the year (don't include commuting miles)												
31 Total commuting miles driven during the year												
32 Total other personal (noncommuting) miles driven												
33 Total miles driven during the year. Add lines 30 through 32												
	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
34 Was the vehicle available for personal use during off-duty hours?												
35 Was the vehicle used primarily by a more than 5% owner or related person?												
36 Is another vehicle available for personal use?												

Section C - Questions for Employers Who Provide Vehicles for Use by Their Employees

Answer these questions to determine if you meet an exception to completing Section B for vehicles used by employees who aren't more than 5% owners or related persons (see instructions).

	Yes	No
37 Do you maintain a written policy statement that prohibits all personal use of vehicles, including commuting, by your employees?		
38 Do you maintain a written policy statement that prohibits personal use of vehicles, except commuting, by your employees? See the instructions for vehicles used by corporate officers, directors, or 1% or more owners		
39 Do you treat all use of vehicles by employees as personal use?		
40 Do you provide more than five vehicles to your employees, obtain information from your employees about the use of the vehicles, and retain the information received?		
41 Do you meet the requirements concerning qualified automobile demonstration use? (See instructions.)		

Note: If your answer to 37, 38, 39, 40, or 41 is "Yes," don't complete Section B for the covered vehicles.

Part VI **Amortization**

(a) Description of costs	(b) Date amortization begins	(c) Amortizable amount	(d) Code section	(e) Amortization period or percentage	(f) Amortization for this year
42 Amortization of costs that begins during your 2016 tax year (see instructions):					
				Total	1,344,971.
43 Amortization of costs that began before your 2016 tax year				43	6,771,800.
44 Total. Add amounts in column (f). See the instructions for where to report				44	8,116,771.

JSA Form **4562** (2016)
6X2310 2.000

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Form 83-105, Page 2 Detail

Part II - Corporate Officer Information

Name:	K B MARSH
Title:	President
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111117
Name:	D F KASSIS
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111118
Name:	S O SHULER JR
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111119
Name:	D R HARRIS
Title:	President
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111120
Name:	S L DOZIER
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111122
Name:	W K KISSAM
Title:	President
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111123
Name:	S D BURCH
Title:	SRVP
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111125

Continued on next page Statement 1

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Form 83-105, Page 2 Detail

Part II - Corporate Officer Information (Cont'd)

Name:	J E ADDISON
Title:	CFO
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111126

Name:	F R HOWARD
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111128

Name:	C B LOVE
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111129

Name:	S A BYRNE
Title:	COO
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111131

Name:	P N XANTHAKOS
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111132

Name:	J M LANDRETH
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111133

Name:	J E SWAN IV
Title:	Controller
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111134

Continued on next page

Form 83-105, Page 2 Detail

Part II - Corporate Officer Information (Cont'd)

Name:	G S CHAMPION
Title:	Secretary
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111135
Name:	M S RANDALL
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111139
Name:	R T LINDSAY
Title:	SRVP
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111141
Name:	R A JONES
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111142
Name:	A C HIGGINS
Title:	V.P.
Address:	220 OPERATION WAY
City, state, zip:	CAYCE, SC 29033
SSN:	111111143

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Mississippi Form 83-120 -- Schedule L Detail

Line 6 - Other current assets

	Beginning	Ending
ACCOUNTS RECEIVABLE- ASSOC COMPANY	13994351	4731796
INTEREST AND DIVIDENDS RECEIVABLE		121727
OTHER CURRENT ASSETS	10356905	
PREPAYMENTS	81880379	86351520
Total	106231635	91205043

Line 9 - Other investments

	Beginning	Ending
INVEST IN ASSOC COMPANIES		2856381
OTHER INVESTMENTS	171160735	177631576
Total	171160735	180487957

Line 14 - Other assets

	Beginning	Ending
ACC DEFERRED INCOME TAXES	277332298	354286724
CLEARING ACCOUNTS	4232	418919
DUE FROM AFFIL DIRECTORS ENDOWMENT	382447	379524
MISC DEFERRED DEBITS	82102622	163564671
PRELIM SURVEY AND INVEST CHGS	198470	322402
REGULATORY ASSET - FASB 109	1775528967	1967097185
UNAMORTIZED DEBT EXPENSE	31259888	35470866
UNAMORTIZED LOSS ON REACQ DEBT	16258766	15116381
Total	2183067690	2536656672

Line 18 - Other current liabilities

	Beginning	Ending
ACCRUED INTEREST PAYABLE	64981071	66073421
ACCRUED TAXES PAY - FEDERAL INCOME	139536235	176366709
ACCRUED TAXES PAY - STATE INCOME	31166055	76470800
ACCRUED TAXES PAYABLE - OTHER	173595618	190023235
ACCTS PAYABLE - ASSOC COS	71894901	61294130
CUSTOMER DEPOSITS	57087060	60283425
DIVIDENDS DECLARED	72300000	77500000
MISC CURRENT AND ACCRUED LIABILITIE	94969814	80313106
TAXES PAYABLE - OTHER	1882026	1970592
TAXES PAYABLE - SALES AND USE	6652941	6525363
Total	714065721	796820781

Statement 4

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Mississippi Form 83-120 -- Schedule L Detail

	Beginning	Ending
Line 21 - Other liabilities		
ACC DEF FED INCOME TAX	1692572092	1883853155
ACC DEF STATE INCOME TAX	217942117	241044075
ACCUM DEF INVEST TAX CREDITS	23580500	22188300
DEFERRED CREDITS - OTHER	73571854	49074144
DUE TO AFFILIATES	212184657	257285183
FASB 109 REGULATORY LIABILITY	147243710	238854458
INJURIES AND DAMAGES RESERVE	5355089	7859531
OBLIGATIONS UNDER CAP LEASE	12477819	20678011
OTHER ASSET RETIREMENT OBLIGATIONS	476223696	509434012
UNAMORT DISCT - LT DEBT	2230185	280853
Total	2863381719	3230551722
Line 26 - Adjustments to Shareholders' Equity		
ADJUSTMENT TO SHAREHOLDERS EQUITY	-2770003	-2973265
Total	-2770003	-2973265

Mississippi Form 83-120 -- Schedule M1, M2 Detail

Sch M-2, Line 3 - Other increases

Other Increases	3
Total	3

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

Mississippi Form 83-122, Detail

Line 7 - Other additions required by law

Federal charitable contribution deduction	NONE
	41,912,434.
Total	41912434

Line 14 - Other deductions authorized by law

Charitable contribution deduction	2736550
	43535724
Total	46272274

Statement 7

SOUTH CAROLINA ELECTRIC and GAS COMPANY

	Combined	SOUTH CAROLINA ELECTRIC and GAS ELIM	Adjustments	SOUTH CAROLINA ELECTRIC and GAS COMPANY
Consolidated Schedules - Form 4562				
Consolidated 4562 Summary				
Part I - Section 179 Expense				
2 Sec 179 property placed in Service in current year				
6 Nonlisted property				
7 Listed property				
8 Total elected cost				
9 Tentative deduction				
10 Carryover from 2015				
12 Sec 179 expense deduction				
13 Carryover to 2017				
Part II - Other Depreciation				
14 Special depreciation allowance	196,749,764.			196,749,764.
15 Property subject to 168(f)(1)				
16 ACRS and other depreciation	2,285,905.			2,285,905.
Part III - MACRS				
17 MACRS deduction - prior years	223,119,828.			223,119,828.
19 General Depreciation System				
a. 3-year property				
b. 5-year property	613,002.			613,002.
c. 7-year property	1,756,409.			1,756,409.
d. 10-year property				
e. 15-year property	3,731,461.			3,731,461.
f. 20-year property	3,662,527.			3,662,527.
g. 25-year property				
h. 27.5-year residential real				
i. 39-year nonresidential real	2,296.			2,296.
20 Alternative Depreciation System				
a. Class life				
b. 12-year				
c. 40-year				
Part IV - Summary				
21 Listed Property				
22 **Total depreciation**	431,921,192.			431,921,192.
42 Amortization - current year	1,344,971.			1,344,971.
43 Amortization - prior year	6,771,800.			6,771,800.
44 **Total Amortization**	8,116,771.			8,116,771.

SOUTH CAROLINA ELECTRIC and GAS COMPANY

	SOUTH CAROLINA ELECTRIC	SOUTH CAROLINA GAS	SOUTH CAROLINA BTL	SOUTH CAROLINA TR
Consolidated Schedules - Form 4562				
Consolidated 4562 Summary	57-0248695	57-0248695	57-0248695	57-0248695
Part I - Section 179 Expense				
2 Sec 179 property placed in Service in current year				
6 Nonlisted property				
7 Listed property				
8 Total elected cost				
9 Tentative deduction				
10 Carryover from 2015				
12 Sec 179 expense deduction				
13 Carryover to 2017				
Part II - Other Depreciation				
14 Special depreciation allowance	196,749,764.			
15 Property subject to 168(f)(1)				
16 ACRS and other depreciation	2,285,905.			
Part III - MACRS				
17 MACRS deduction - prior years	223,119,828.			
19 General Depreciation System				
a. 3-year property				
b. 5-year property	613,002.			
c. 7-year property	1,756,409.			
d. 10-year property				
e. 15-year property	3,731,461.			
f. 20-year property	3,662,527.			
g. 25-year property				
h. 27.5-year residential real				
i. 39-year nonresidential real	2,296.			
20 Alternative Depreciation System				
a. Class life				
b. 12-year				
c. 40-year				
Part IV - Summary				
21 Listed Property				
22 Total depreciation	431,921,192.			
42 Amortization - current year	1,344,971.			
43 Amortization - prior year	6,771,800.			
44 Total Amortization	8,116,771.			

SOUTH CAROLINA ELECTRIC & GAS COMPANY		
FEIN: 57-0248695		
2016		
FORM 83-110, LINE 5		
ACCUMULATED DEFERRED INCOME TAXES	2,147,085,530	
REGULATORY LIABILITIES	238,854,460	
DEFERRED CREDITS- OTHER	56,933,673	
	2,442,873,663	
FORM 83-122, LINE 6		
FEDERAL DEPRECIATION PER FORM 4562	431,921,189	
FORM 83-122, LINE 7		
FEDERAL LOSS ON SALE OF ASSETS	38,024,208	
FEDERAL AMORTIZATION	8,116,771	
FEDERAL 481A	(4,228,545)	
	41,912,434	
FORM 83-122, LINE 13		
STATE DEPRECIATION PER 4562	322,446,266	
FORM 83-122, LINE 14		
STATE LOSS ON SALE OF ASSETS	40,623,847	
STATE AMORTIZATION	10,206,263	
STATE 481A	(7,294,386)	
CHARITABLE CONTRIBUTION ADJUSTMENT	2,736,550	
	46,272,274	

FORMS (TAX)

FORM NUMBER

NC 405

JURISDICTION

NORTH CAROLINA

MONTH	YEAR
	2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

SCANA CORPORATION

E-file Authorization Form

Entity	South Carolina Electric and Gas Company
Type	Tax Return
Form	Form CD-405
Jurisdiction	North Carolina
Period	12/31/2016

Authorization

I hereby declare that I have examined this form and accompanying schedules and statements, and to the best of my knowledge and belief, this is a true, correct, and complete return.

	Controller	10/11/2017
Signature	Title	Date

C Corporation Tax Return 2016

CD-405 (40)

North Carolina Department of Revenue

For calendar year 2016, or other tax year beginning 16 and ending

DOR Use Only

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
220 OPERATION WAY
CAYCE SC 29033-3701

Federal Employer ID Number 570248695
N.C. Secretary of State ID Number 0911500
NAICS Code 221100

☐ Initial Return ☐ Short Year Return ☐ Captive REIT ☐ Non U.S./Foreign ☐ NC-Rehab ☐ CD-479 is attached
☐ Final Return ☐ Amended Return ☐ Tax Exempt ☐ Combined Return ☐ NC-478 is attached ☐ Has Escheatable Property

SOUT 220 29033 570248695 0911500 221100

PP 0 PFSP IR N FR N SR N AR N RE N TE N

TN 8032179000 NF N CR N NCR N 478 N 479 N EP N

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

220 OPERATION WAY CAYCE SC 29033

GR	2998699530	09	0	21	0	31	0
TA	15019055753	10	-27000062	22	0	32	0
01	0	11	107851633	24	0	36	0
HCE	N	13	0	26	0	EU	
02	0	15	0	27	0	37A	0
03	0	16	80851571	29A	0	37B	0
05	200	17	0000000	29B	0	40	0
06	200	18	0	29C	0	41	0
07	0	19	0	29D	0	42	0
08	0	20	0	29E	0	43	0

6300140018

Sch. A Computation of Franchise Tax

1. Net Worth	NONE
Holding Company Exception	N
2. Investment in N.C. Tangible Property	0
3. Appraised Value of N.C. Tangible Property	0
4. Taxable Amount	NONE
5. Total Franchise Tax Due	200
6. Payment with Franchise Tax Extension	200
7. Tax Credits	0
8. Franchise Tax Due	0

9. Franchise Tax Overpaid	0

Sch. B Computation of Corporate Income Tax

10. Federal Taxable Income	-27000062
11. Adjustments to Federal Taxable Income	107851633
12. Net Income Before Contributions	80851571
13. Contributions to Donees Outside N.C.	0
14. N.C. Taxable Income	80851571
15. Nonapportionable Income	0
16. Apportionable Income	80851571
17. Apportionment Factor	NONE %

Sign Return Below ☐ **Refund Due** 0 ☒ **Payment Due** 0

CONTROLLER — Signature and Title of Officer

803-217-9000 — Corporate Telephone Number

10-11-2017 — Date

Signature of Paid Preparer

Preparer's Telephone Number

Preparer's FEIN, SSN, or PTIN ☐ FEIN ☐ SSN ☐ PTIN

I certify that, to the best of my knowledge, this return is accurate and complete.

Mail to: NCDOR, P.O. Box 25000, Raleigh, N.C. 27640-0500. Returns are due by the 15th day of the 4th month after the end of the income year.

6D3921 1.000

CD-419 (40)
8-31-16

Application for Corporate Income Tax Extension

North Carolina Department of Revenue

North Carolina law provides for an extension of time to file a North Carolina corporate tax return (Form CD-405, CD-401S, or CD-418) When timely filed, Form CD-419 extends the due date of the return by six months An extension of time to file the return does not extend the time to pay the amount of tax due If the taxpayer does not pay the full amount of tax due by the original due date of the return, interest and penalties will be assessed North Carolina does not accept the federal extension in lieu of Form CD-419 (Note For North Carolina income tax purposes, an income year that ends on any day other than the last day of the month is considered to end on the last day of the month nearest to the last day of the actual income year)

To obtain an extension and pay any tax due, a taxpayer must file Form CD-419 by the original due date of the corporate tax return A taxpayer can use the Department's website or the personalized coupon below The Department's website offers two electronic options (1) an online filing and payment system, and (2) an eFile program For more information, visit www dornc com and search for online file and pay

The Department strongly encourages taxpayers to file and pay electronically Please note, however, that the Department's eFile program **DOES NOT** permit the electronic filing of the "North Carolina Annual Report for Business Corporations" (Form CD-479) Therefore, if a corporation e-files its corporate tax return, the annual report must be filed either (1) online directly with the NC Secretary of State http //www sosnc gov/Corporations/arentry aspx, or (2) in paper form with the Department of Revenue If the corporation chooses to file the annual report in paper form with the Department, include the annual report fee ($25 00) with the corporation's expected income tax liability (See Line 4)

IMPORTANT. Attaching the annual report to an electronically filed tax return does not constitute filing the annual report Failure to timely file the annual report with the NC Secretary of State may result in a corporate administrative dissolution under G S 55-14-20 or revocation under G S 55-15-30

Worksheet for Computation of Tax Paid with Application for Extension

1.	**Total Franchise Tax Due** *(Minimum $200 00)*	200.00
2	**Franchise Tax Credits Taken** *(From Form CD-425)*	
3	**Net Franchise Tax Due** Line 1 minus Line 2	200.00
4	**Total Corporate Income Tax Due** *(Include Annual Report Fee only if filing Annual Report in paper form with the Department of Revenue)*	
5	**Estimated Income Tax Payments** *(Include any prior year's overpayment applied to current tax year)*	
6	**Corporate Income Tax Credits Taken** *(From Form CD-425)*	
7.	**Net Corporate Income Tax Due** Line 4 minus Line 5 and Line 6	
8.	**Total Franchise and Corporate Income Tax Due with this Application** Line 3 plus (or minus) Line 7	200.00

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6S39D1 1 000

CD-419 (40)
8-13-13

Application for Corporate Income Tax Extension

North Carolina Department of Revenue

FEIN 570248695 N NP/TE N NF N CO/MA Tax year starting 01 01 16

SOS Mail to NCDOR, PO Box 25000, Raleigh, NC 27640-0520 and ending 12 31 16

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
220 OPERATION WAY
CAYCE SC 29033-

Total Income Tax Due
$ .00

6420140010

12165 5702486957 0000000 06530

CD-419 (40)
8-31-16

Application for Franchise Tax Extension

North Carolina Department of Revenue

North Carolina law provides for an extension of time to file a North Carolina corporate tax return (Form CD-405, CD-401S, or CD-418) When timely filed, Form CD-419 extends the due date of the return by six months An extension of time to file the return does not extend the time to pay the amount of tax due If the taxpayer does not pay the full amount of tax due by the original due date of the return, interest and penalties will be assessed North Carolina does not accept the federal extension in lieu of Form CD-419 (Note For North Carolina franchise tax purposes, an income year that ends on any day other than the last day of the month is considered to end on the last day of the month nearest to the last day of the actual income year)

To obtain an extension and pay any tax due, a taxpayer must file Form CD-419 by the original due date of the corporate tax return A taxpayer can use the Department's website or the personalized coupon below The Department's website offers two electronic options (1) an online filing and payment system, and (2) an eFile program For more information, visit www dornc com and search for online file and pay

The Department strongly encourages taxpayers to file and pay electronically Please note, however, that the Department's eFile program **DOES NOT** permit the electronic filing of the "North Carolina Annual Report for Business Corporations" (Form CD-479). Therefore, if a corporation e-files its corporate tax return, the annual report must be filed either (1) online directly with the NC Secretary of State http //www sosnc gov/Corporations/arentry aspx, or (2) in paper form with the Department of Revenue

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Worksheet for Computation of Tax Paid with Application for Extension

1	**Total Franchise Tax Due** *(Minimum $200 00)*	
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4	**Total Corporate Income Tax Due** *(Include Annual Report Fee only if filing Annual Report in paper form with the Department of Revenue)*	
5	**Estimated Income Tax Payments** *(Include any prior year's overpayment applied to current tax year)*	
6	**Corporate Income Tax Credits Taken** *(From Form CD-425)*	
7.	**Net Corporate Income Tax Due** Line 4 minus Line 5 and Line 6	
8.	**Total Franchise and Corporate Income Tax Due with this Application** Line 3 plus (or minus) Line 7	200.00

Cut Here

6S39D2 1 000

CD-419 (40)
8-13-13

Application for Franchise Tax Extension

North Carolina Department of Revenue

FEIN 570248695 SOS	Tax year starting 01 01 16	and ending 12 31 16
SOUTH CAROLINA ELECTRIC AND GAS COMPANY	N NP/TE N NF N CO/MA	
220 OPERATION WAY CAYCE SC 29033-	Total Franchise Tax Due $	200.00

Mail to NCDOR, PO Box 25000, Raleigh, NC 27640-0520

6410140007

12165 5702486957 0000000 05037

CD-405 2016 Page 2 (40)

Legal Name *(First 10 Characters)* SOUTH CARO Federal Employer ID Number 570248695

CD-405 Line-by-Line Information

N.C. Education Endowment Fund: You may contribute to the N.C. Education Endowment Fund by making a contribution or designating some or all of your overpayment to the Fund. To make a contribution, enclose Form NC-EDU and your payment of 0

Sch. B Computation of Corporate Income Tax

18.	Income Apportioned to N.C.	NONE
19.	Nonapportionable Income Allocated to N.C.	0
20.	Income Subject to N.C. Tax	NONE
21.	% Depletion over Cost - N.C. Property	0
22.	State Net Loss (Attach schedule)	0
23.	Income Before Contributions to N.C. Donees	NONE
24.	Contributions to N.C. Donees	0
25.	Net Taxable Income	NONE
26.	N.C. Net Income Tax	NONE
27.	Annual Report Fee (Include $25.00 only if Form CD-479 is attached in paper form; otherwise, enter zero.)	0
28.	Add Lines 26 and 27	NONE
29.	Payments and Credits Stmt 1	
	a. Income Tax Extension	0
	b. 2016 Estimated Tax (previous payments if amended)	0
	c. Partnership (Include Form D-403, NC K-1)	0
	d. Nonresident Withholding (include 1099 or W-2)	0
	e. Tax Credits	0
30.	Add Lines 29a through 29e	0
31.	Income Tax Due	NONE
32.	Income Tax Overpaid	0

Tax Due or Refund

33.	Franchise Tax Due or Overpayment	0
34.	Income Tax Due or Overpayment	NONE
35.	Balance of Tax Due or Overpayment	NONE
36.	Underpayment of Estimated Income Tax	0
EU.	Exception to Underpayment of Estimated Tax	
37.	a. Interest	0
	b. Penalties	0
	c. Add Lines 37a and 37b	0
38.	Total Due	NONE
39.	Overpayment	0
40.	2017 Estimated Income Tax	0
41.	N.C. Nongame and Endangered Wildlife Fund	0
42.	N.C. Education Endowment Fund	0
43.	Amount to be Refunded	0

Sch. C Net Worth

1.	Total assets	19291388313
2.	Total liabilities	9680479622
3.	Line 1 minus Line 2	9610908691
4.	Treasury Stock	0
5.	Accumulated depreciation, depletion, and amortization permitted for income tax purposes	7266166080
6.	Line 3 minus Lines 4 and 5	2344742611
7.	Affiliated Indebtedness (Attach schedule)	0
8.	Line 6 plus (or minus) Line 7	2344742611
9.	Apportionment factor	NONE%
10.	Net Worth	NONE

Sch. D Investment in N.C. Tangible Property

	Inventory valuation method	
1.	Total Inventories located in N.C.	0
2.	Total furniture, fixtures, and M & E located in N.C.	0
3.	Total land and buildings located in N.C.	0
4.	Total leasehold improvements and other N.C. tangible property	0
5.	Add Lines 1 through 4	0
6.	Accumulated depreciation, depletion, and amortization with respect to N.C. tangible property	0
7.	Investment in N.C. Tangible Property	0

Sch. E Appraised Value of N.C. Tangible Property

1.	County tax value of N.C. tangible property	0
2.	Appraised value of N.C. tangible property	0

Sch. G Federal Taxable Income Before NOL Deduction

1.	a. Gross receipts or sales	2998699530
	b. Returns and allowances	0
	c. Balance - Line 1a minus Line 1b	2998699530
2.	Cost of goods sold (Attach schedule) Stmt 1	1088310803
3.	Gross Profit (Line 1c minus Line 2)	1910388727
4.	Dividends (Attach schedule)	0
5.	a. Interest on obligations of U.S. and its instrumentalities	0
	b. Other interest	235401711
6.	Gross rents	20964105
7.	Gross royalties	0
8.	Capital gain net income (Attach schedule) Stmt 1	NONE
9.	Net gain (loss) (Attach schedule)	-38024208
10.	Other income (Attach schedule) Stmt 2	10233647
11.	Total income	2138963982
12.	Compensation of officers (Attach schedule) Stmt 3	15144833
13.	Salaries and wages (less employment credits)	55188382
14.	Repairs and maintenance	215401652
15.	Bad debts	6349958
16.	Rents	6587833
17.	Taxes and licenses Stmt 4	230655590
18.	Interest Stmt 4	297298406
19.	Charitable contributions	NONE
20.	a. Depreciation	431921192
	b. Depreciation included in cost of goods sold	0
	c. Balance - Line 20a minus 20b	431921192
21.	Depletion	0
22.	Advertising	371874
23.	Pension, profit-sharing, and similar plans	1368809
24.	Employee benefit programs	43614763
25.	Domestic production activities deduction	0
26.	Other deductions (Attach schedule) Stmt 4	862060752
27.	Total Deductions	2165964044
28.	Taxable Income Per Federal Return Before NOL and Special Deductions	-27000062
29.	Special Deductions	0
30.	Federal Taxable Income	-27000062

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Legal Name *(First 10 Characters)* SOUTH CARO Federal Employer ID Number 570248695

Sch. H Adjustments to Federal Taxable Income

1.	Additions		
	a. Taxes based on net income	1a.	0
	b. Contributions	1b.	0
	c. Royalties to related members	1c.	0
	d. Net interest expense to related members	1d.	0
	e. Expenses attributable to income not taxed	1e.	0
	f. Domestic production activities deduction	1f.	NONE
	g. Bonus depreciation	1g.	473833623
	h. Section 179 expense deduction	1h.	0
	i. Other (Attach schedule)	1i.	0
2.	Total Additions	2.	473833623
3.	Deductions		
	a. U.S. obligation interest (net of expenses)	3a.	0
	b. Other deductible dividends	3b.	0
	c. Royalties received from related members	3c.	0
	d. Qualified interest expense to related members	3d.	0
	e. Bonus depreciation	3e.	365981990
	f. Section 179 expense deduction	3f.	0
	g. Other (Attach schedule)	3g.	0
4.	Total Deductions	4.	365981990
5.	Adjustments to Federal Taxable Income	5.	107851633

Sch. I Contributions

1.	Contributions to Donees Outside N.C.		
	a. Total contributions to donees outside N.C.	1a.	0
	b. Multiply Schedule B, Line 12 by 5%, if Line 12 is greater than zero. Otherwise enter zero.	1b.	0
	c. Amount Deductible	1c.	0
2.	Contributions to N.C. Donees		
	a. Total contributions to N.C. donees other than those listed in Line 2d	2a.	0
	b. Multiply Sch. B, Line 23 by 5%, if Line 23 is greater than zero. Otherwise enter zero.	2b.	0
	c. Enter the lesser of Line 2a or 2b	2c.	0
	d. Total contributions to the State of N.C. and its political subdivisions	2d.	0
	e. Amount Deductible	2e.	0

Other Information - All Taxpayers Must Complete this Schedule

1. a. State of incorporation SC
   b. Date incorporated 07 19 24
2. Date of N.C. Certificate of Authority
3. a. Regular or principal trade or business in N.C. UTILITY
   b. Regular or principal trade or business everywhere UTILITY
4. Principal place business is directed or managed CAYCE, SC
5. What was the last year the IRS redetermined the corporation's federal taxable income?
6. a. Were adjustments reported to N.C.?
   b. If so, when?
7. Does this corporation finance or discount its receivables through a related or an affiliated company? N
8. Is this corporation subject to franchise tax but not N.C. income tax because the corporation's income tax activities are protected under P.L. 86-272? (If yes, attach explanation) N
9. Officers' names and addresses: See Statement 5

President

Vice-President

Secretary

Treasurer

Explanation of Changes for Amended Return:

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Legal Name *(First 10 Characters)* SOUTH CARO   Federal Employer ID Number 570248695

Sch. L Balance Sheet per Books

Assets		Beginning of Tax Year (a)	(b)	End of Tax Year (c)	(d)
1.	Cash		110056888		112818510
2.	a. Trade notes and accounts receivable	521796470		514133020	
	b. Less allowance for bad debts	(2964230)	518832240	(3239931)	510893089
3.	Inventories		171415921		172900770
4.	a. U.S. government obligations		0		0
	b. State and other obligations		0		0
5.	Tax-exempt securities		0		0
6.	Other current assets (Attach schedule) See Statement 6		106231635		91205043
7.	Loans to shareholders		0		0
8.	Mortgage and real estate loans		0		0
9.	Other investments (Attach schedule) See Statement 6		171160735		180487957
10.	a. Buildings and other depreciable assets	14615659537		15686426272	
	b. Less accumulated depreciation	(4150427302)	10465232235	(4272332560)	11414093712
11.	a. Depletable assets	0		0	
	b. Less accumulated depletion	(0)	0	(0)	0
12.	Land (net of any amortization)		0		0
13.	a. Intangible assets (amortizable only)	0		0	
	b. Less accumulated amortization	(0)	0	(0)	0
14.	Other assets (Attach schedule) See Statement 6		2183067690		2536656672
15.	Total Assets		13725997344		15019055753
	Liabilities and Shareholders' Equity				
16.	Accounts payable		392595365		198630173
17.	Mortgages, notes, and bonds payable in less than 1 year		303880566		525461103
18.	Other current liabilities (Attach schedule) See Statement 6		714065721		796820781
19.	Loans from shareholders		0		0
20.	Mortgages, notes, and bonds payable in 1 year or more		4429036067		4929015843
21.	Other liabilities (Attach schedule) See Statement 7		2863381719		3230551722
22.	Capital stock: a. Preferred Stock	100000		100000	
	b. Common Stock	576405122	576505122	576405122	576505122
23.	Additional paid-in capital See Statement 7		2183832337		2283832337
24.	Retained earnings - Appropriated (Attach schedule)		0		0
25.	Retained earnings - Unappropriated		2265470450		2481211937
26.	Adjustments to shareholders' equity (Attach schedule) Stmt 7		-2770003		-2973265
27.	Less cost of treasury stock		(0)		(0)
28.	Total Liabilities and Shareholders' Equity		13725997344		15019055753

Sch. M-1 Reconciliation of Income (Loss) per Books with Income per Return

1.	Net income (loss) per books		512691484	7.	Income recorded on books this year not included on this return:		
2.	Federal income tax		209229479				
3.	Excess of capital losses over capital gains		0		Tax-exempt interest	$ 0	
4.	Income subject to tax not recorded on books this year:				Stmt 8	35789944	
	Stmt 8		-25961383				35789944
5.	Expenses recorded on books this year not deducted on this return:			8.	Deductions on this return not charged against book income this year:		
	a. Depreciation	$ 4228547			a. Depreciation	$ 218786376	
	b. Charitable Contributions	$ 2736550			b. Charitable Contributions	$ 0	
	c. Travel and entertainment	$ 1001437			Stmt 9	555020472	
	Stmt 8	78670616					773806848
			86637150	9.	Add Lines 7 and 8		809596792
6.	Add Lines 1 through 5		782596730	10.	Income		-27000062

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Legal Name *(First 10 Characters)* SOUTH CARO Federal Employer ID Number 570248695

Sch. M-2 Retained Earnings Analysis

1. Balance at beginning of year	2265470450	5. Distributions: a. Cash	296950000
2. Net income (loss) per books	512691484	b. Stock	0
3. Other increases: Stmt 10		c. Property	0
		6. Other decreases:	0
	3	7. Add Lines 5 and 6	296950000
4. Add Lines 1, 2, and 3	2778161937	8. Balance at End of Year	2481211937

Sch. N Nonapportionable Income

(A) Nonapportionable Income	(B) Gross Amounts	(C) Related Expenses	(D) Net Amounts	(E) Net Amounts Allocated Directly to N.C.
1. Nonapportionable income			0	
2. Nonapportionable Income Allocated to N.C.				0

Explanation of why income listed is nonapportionable income rather than apportionable income:

Sch. O Computation of Apportionment Factor

Part 1. Domestic and Other Corporations Not Apportioning Franchise or Income Outside N.C. 0%

Part 2. Corporations Apportioning Franchise or Income to N.C. and to Other States

	1. Within North Carolina (a) Beginning Period	1. Within North Carolina (b) Ending Period	2. Total Everywhere (a) Beginning Period	2. Total Everywhere (b) Ending Period	Factor
1. Land	0	0	0	0	
2. Buildings	0	0	0	0	
3. Inventories	NONE	NONE	171415921	172900769	
4. Other property	NONE	NONE	4469790143	0820695340	
5. Total	NONE	NONE	4641206064	0993596109	
6. Average value of property	NONE		2817401087		
7. Rented Property	NONE		52702664		
8. Property Factor	NONE		2870103751		NONE%
9. Gross Payroll	NONE		271947554		
10. Compensation of general executive officers	0		0		
11. Payroll Factor	NONE		271947554		NONE%
12. Sales Factor	NONE		3015062430		NONE%
13. Total of Factors					NONE%
14. N.C. Apportionment Factor					NONE%

Part 3. Corporations Apportioning Franchise or Income to N.C. and to Other States Using Single Sales Factor 0%

Part 4. Special Apportionment 0%

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North Carolina Form CD-405, Page 2 Detail

Sch B, Line 29 - Tax Payments	Date	Amount
		NONE

Sch G, Line 2 - Cost of goods sold

1. Inventory at beginning of year	171,415,921.
2. Merchandise bought for manufacture or sale	5,268,408.
3. Cost of labor	-420,319.
4. Additional Section 263A cost	
5. Other costs	1,084,947,563.
6. Total - Add lines 1 through 5 above	1,261,211,573.
7. Inventory at end of year	172,900,770.
8. Cost of goods sold - subtract line 7 from line 6	1,088,310,803.

Sch G - Cost of goods sold - Other costs

ELECTRIC - DISTRIBUTION	15,271,035.
ELECTRIC - GENERAL	-2,620,344.
ELECTRIC - PRODUCTION	826,249,729.
ELECTRIC - SALES PROMOTION	6,663,922.
ELECTRIC - TRANSMISSION	9,288,573.
GAS - CUSTOMER ACCOUNTS	53,410,559.
GAS - DISTRIBUTION	9,133,565.
GAS - PRODUCTION	184,185,087.
GAS - TRANSMISSION	235.
OTHER COSTS	-16,634,798.
Total	1,084,947,563.

Sch G, Line 8 - Net gains (losses)

Capital gain net income	NONE
Total	NONE

North Carolina Form CD-405, Page 2 Detail

Sch G, Line 10 - Other income

GAIN ON LAND SALES	
INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	-4,833,278.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	15,066,925.
Total	10,233,647.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

North Carolina Form CD-405, Page 2 Detail

Sch G, Line 12 - Compensation of officers

Name	Title	SSN	% Bus	% Com	% Pref	Compensation Amount
G T DEVLIN		111-11-1111	100.000			507,901.
K R JACKSON	SRVP	111-11-1112	100.000			440,676.
R M SENN	SRVP	111-11-1113	100.000			521,767.
J B ARCHIE	SRVP	111-11-1114	100.000			663,712.
W J TURNER III	V.P.	111-11-1115	100.000			343,678.
T D GATLIN	V.P.	111-11-1116	100.000			466,822.
K B MARSH	President	111-11-1117	100.000			1,000,000.
D F KASSIS	V.P.	111-11-1118	100.000			320,047.
S O SHULER JR	V.P.	111-11-1119	100.000			274,630.
D R HARRIS	President	111-11-1120	100.000			678,557.
S L DOZIER	V.P.	111-11-1122	100.000			311,757.
W K KISSAM	President	111-11-1123	100.000			713,735.
S D BURCH	SRVP	111-11-1125	100.000			511,044.
J E ADDISON	CFO	111-11-1126	100.000			1,210,131.
F R HOWARD	V.P.	111-11-1128	100.000			337,440.
C B LOVE	V.P.	111-11-1129	100.000			320,282.
S A BYRNE	COO	111-11-1131	100.000			1,000,000.
P N XANTHAKOS	V.P.	111-11-1132	100.000			248,261.
J M LANDRETH	V.P.	111-11-1133	100.000			397,926.
J E SWAN IV	Controller	111-11-1134	100.000			494,765.
G S CHAMPION	Secretary	111-11-1135	100.000			372,357.
M S RANDALL	V.P.	111-11-1139	100.000			274,451.
R T LINDSAY	SRVP	111-11-1141	100.000			199,954.
R A JONES	V.P.	111-11-1142	100.000			278,471.
A C HIGGINS	V.P.	111-11-1143	100.000			412,162.
Total compensation of officers						12,300,526.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

North Carolina Form CD-405, Page 2 Detail

Sch G, Line 17 - Taxes

TAXES AND LICENSES	230,655,590.
Total	230,655,590.

Sch G, Line 18 - Interest expense

INTEREST EXPENSE AFFILIATE	6,644,766.
INTEREST EXPENSE	290,653,640.
Total	297,298,406.

Sch G, Line 26 - Other deductions

Travel & entertainment	1,001,437.
Amortization expense	8,116,771.
POLLUTION CONTROL	10,705,348.
INJURIES AND DAMAGES	5,807,027.
INSURANCE	7,158,823.
MERCHANDISING EXPENSES	1,031,448.
MISCELLANEOUS DEDUCTIONS	39,340,430.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	51,659,518.
OFFICE SUPPLIES AND EXPENSES	20,537,993.
OUTSIDE SERVICES	16,406,895.
PIPELINE INTEGRITY	-17,084,713.
481A ADJUSTMENT	-4,228,547.
RESEARCH AND DEVELOPMENT	721,608,322.
Total	862,060,752.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

North Carolina Form CD-405, Page 3 Detail

Other Information - Officer's Name and Address

Officer's Name	Officer's Title	Street	City, State
G T DEVLIN		220 OPERATION WAY	CAYCE, SC 29033
K R JACKSON	SRVP	220 OPERATION WAY	CAYCE, SC 29033
R M SENN	SRVP	220 OPERATION WAY	CAYCE, SC 29033
J B ARCHIE	SRVP	220 OPERATION WAY	CAYCE, SC 29033
W J TURNER III	V.P.	220 OPERATION WAY	CAYCE, SC 29033
T D GATLIN	V.P.	220 OPERATION WAY	CAYCE, SC 29033
K B MARSH	President	220 OPERATION WAY	CAYCE, SC 29033
D F KASSIS	V.P.	220 OPERATION WAY	CAYCE, SC 29033
S O SHULER JR	V.P.	220 OPERATION WAY	CAYCE, SC 29033
D R HARRIS	President	220 OPERATION WAY	CAYCE, SC 29033
S L DOZIER	V.P.	220 OPERATION WAY	CAYCE, SC 29033
W K KISSAM	President	220 OPERATION WAY	CAYCE, SC 29033
S D BURCH	SRVP	220 OPERATION WAY	CAYCE, SC 29033
J E ADDISON	CFO	220 OPERATION WAY	CAYCE, SC 29033
F R HOWARD	V.P.	220 OPERATION WAY	CAYCE, SC 29033
C B LOVE	V.P.	220 OPERATION WAY	CAYCE, SC 29033
S A BYRNE	COO	220 OPERATION WAY	CAYCE, SC 29033
P N XANTHAKOS	V.P.	220 OPERATION WAY	CAYCE, SC 29033
J M LANDRETH	V.P.	220 OPERATION WAY	CAYCE, SC 29033
J E SWAN IV	Controller	220 OPERATION WAY	CAYCE, SC 29033
G S CHAMPION	Secretary	220 OPERATION WAY	CAYCE, SC 29033
M S RANDALL	V.P.	220 OPERATION WAY	CAYCE, SC 29033
R T LINDSAY	SRVP	220 OPERATION WAY	CAYCE, SC 29033
R A JONES	V.P.	220 OPERATION WAY	CAYCE, SC 29033
A C HIGGINS	V.P.	220 OPERATION WAY	CAYCE, SC 29033

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

North Carolina Form CD-405, Page 4 Detail

	Beginning	Ending
Sch L, Line 6 - Other current assets		
ACCOUNTS RECEIVABLE- ASSOC COMPANY	13,994,351.	4,731,796.
INTEREST AND DIVIDENDS RECEIVABLE		121,727.
OTHER CURRENT ASSETS	10,356,905.	
PREPAYMENTS	81,880,379.	86,351,520.
Total	106,231,635.	91,205,043.
Sch L, Line 9 - Other investments		
INVEST IN ASSOC COMPANIES		2,856,381.
OTHER INVESTMENTS	171,160,735.	177,631,576.
Total	171,160,735.	180,487,957.
Sch L, Line 14 - Other assets		
ACC DEFERRED INCOME TAXES	277,332,298.	354,286,724.
CLEARING ACCOUNTS	4,232.	418,919.
DUE FROM AFFIL DIRECTORS ENDOWMENT	382,447.	379,524.
MISC DEFERRED DEBITS	82,102,622.	163,564,671.
PRELIM SURVEY AND INVEST CHGS	198,470.	322,402.
REGULATORY ASSET - FASB 109	1,775,528,967.	1,967,097,185.
UNAMORTIZED DEBT EXPENSE	31,259,888.	35,470,866.
UNAMORTIZED LOSS ON REACQ DEBT	16,258,766.	15,116,381.
Total	2,183,067,690.	2,536,656,672.
Sch L, Ln 18 - Other current liabilities		
ACCRUED INTEREST PAYABLE	64,981,071.	66,073,421.
ACCRUED TAXES PAY - FEDERAL INCOME	139,536,235.	176,366,709.
ACCRUED TAXES PAY - STATE INCOME	31,166,055.	76,470,800.
ACCRUED TAXES PAYABLE - OTHER	173,595,618.	190,023,235.
ACCTS PAYABLE - ASSOC COS	71,894,901.	61,294,130.
CUSTOMER DEPOSITS	57,087,060.	60,283,425.
DIVIDENDS DECLARED	72,300,000.	77,500,000.
MISC CURRENT AND ACCRUED LIABILITIE	94,969,814.	80,313,106.
TAXES PAYABLE - OTHER	1,882,026.	1,970,592.
TAXES PAYABLE - SALES AND USE	6,652,941.	6,525,363.

Continued on next page

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

North Carolina Form CD-405, Page 4 Detail

	Beginning	Ending
Sch L, Ln 18 - Other current liabilities (Cont'd)		
Total	714,065,721.	796,820,781.

Sch L, Line 21 - Other liabilities		
ACC DEF FED INCOME TAX	1,692,572,092.	1,883,853,155.
ACC DEF STATE INCOME TAX	217,942,117.	241,044,075.
ACCUM DEF INVEST TAX CREDITS	23,580,500.	22,188,300.
DEFERRED CREDITS - OTHER	73,571,854.	49,074,144.
DUE TO AFFILIATES	212,184,657.	257,285,183.
FASB 109 REGULATORY LIABILITY	147,243,710.	238,854,458.
INJURIES AND DAMAGES RESERVE	5,355,089.	7,859,531.
OBLIGATIONS UNDER CAP LEASE	12,477,819.	20,678,011.
OTHER ASSET RETIREMENT OBLIGATIONS	476,223,696.	509,434,012.
UNAMORT DISCT - LT DEBT	2,230,185.	280,853.
Total	2,863,381,719.	3,230,551,722.

Sch L, Ln 23 - Paid-in/capital surplus		
ADDITIONAL PAID-IN CAPITAL	2,183,832,337.	2,283,832,337.
Total	2,183,832,337.	2,283,832,337.

Sch L, Line 26 - Adjustments to shareholder's equity		
ADJUSTMENT TO SHAREHOLDERS EQUITY	-2,770,003.	-2,973,265.
Total	-2,770,003.	-2,973,265.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

North Carolina Form CD-405, Page 4 Detail

SCH M-1, Ln 4 - Taxable income not on books this year

Gain (loss) on disposition of assets	267,022.
BA_N02_EMIS_ALLOW	-146,028.
E _BOOK_CAP_INT_EQUITY	-26,082,377.
Total	-25,961,383.

Sch M-1, Ln 5 - Expenses on books not deducted in return

State taxes	-529,600.
Bad debts	-44,400.
AB_NUCL_PLANT_REF	15,580,797.
AS_ENVIRO_CLEAN	798,991.
AY_LTD	-601,447.
BI_PREPAIDS	1,113,959.
BT_PSHIP_TAX_BRANDON	19,696.
CH_INTEREST_INCOME_AMEND_RTNS	32,629.
BV_REG_ASSET_CANADYS_U2-3	9,122,722.
G_INJURIES	2,504,441.
I _DEF_FUEL	31,549,990.
K_MAJOR_MAINTENANCE	-5,521,170.
P_REAQ_DEBT	1,142,385.
T _REG_ASSET_CUST	335,103.
U_PENSION	19,604,703.
X _VCS	183,816.
Y_REG_ASSET_RECOV_CAP	296,000.
CC_NET_METER	1,757,750.
CD_PSHIP_TAX_SRFI	63,862.
CG_JAD_TERMINATION	1,200,000.
GR_ALT_FUEL_CREDIT_ADDBACK	60,389.
Total	78,670,616.

Sch M-1, Ln 7 - Income on books not in return

Gain (loss) on disposition of assets	38,912,666.
AG_CIAC	-17,084,713.
BB_S02_EMIS_ALLOW	-8,862.
BX_REG_ASSET_NND_CARRYING	13,970,853.
Total	35,789,944.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

North Carolina Form CD-405, Page 4 Detail

Sch M-1, Ln 8 - Deductions on tax return not on books

State taxes	-31,515,978.
Bad debts	-320,101.
Amortization	8,116,771.
AH_VACATION	521,110.
AI_GRANTS	400,000.
AK_LINE_PACK	-1,683.
AM_CPI	-202,222,083.
AO_POLLUTION	-1,344,598.
AP_FUKISHIMA	427,884.
AQ_BONUS	-2,011,086.
AT_STORM_DAMAGE	23,607,305.
AU_OPEB_TEMP	-3,073,318.
AV_ELEC_SIDE_MGT	-519,610.
AW_RESEARCH	721,608,322.
AX_LOBBYING	-218,753.
AY_LTD	-19,207.
BF_OFFICER_COMP	-2,505,282.
BH_PSHIP_TAX_CANADYS	519,819.
BI_PREPAIDS	2,331,717.
BJ_REG_ASSET_ENVIRON	-94,783.
BM_DIRENDOW_PERM	-28,544.
BM_DIRENDOW_TEMP	-128,484.
BR_GAS_WNA_CAP	1,811,353.
BU_PSHIP_TAX_LOUISA	4,737.
CJ_PSHIP_TAX_BRUNNER_ISLAND	906,042.
CI_REG_ASSET_PILOT_MODEL_ACCT_ORDER	1,682,475.
CA_REG_ASSET_MCMEEKIN	1,005,199.
E_BOOK_CAP_INT_DEBT	16,522,358.
F_UNICAP	222,266.
GL_DEF_PIPE_INTEG	2,233,149.
H_AUTO_DEPR	-2,445,692.
I_DEF_FUEL	7,232,654.
N_REG_ASSET_DEF_CAP	6,238,082.
Q_KEY_EMP_TEMP	1,748,575.
R_NUC_DECOM_TEMP	-3,224,920.
S_ERIP	235,528.
W_CONT_NONCASH	2,177.
CF_CYBER_SECURITY	7,317,071.
Total	555,020,472.

North Carolina Form CD-405, Page 5 Detail

Sch M-2, Line 3 - Other increases

Other Increases	3.
Total	3

FORMS (TAX)

FORM NUMBER

STATE 1120

JURISDICTION

NEW JERSEY

MONTH | YEAR

2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

SCANA CORPORATION

E-file Authorization Form

Entity	South Carolina Electric and Gas Company
Type	Tax Return
Form	Form CBT-100
Jurisdiction	New Jersey
Period	12/31/2016

Authorization

I hereby declare that I have examined this form and accompanying schedules and statements, and to the best of my knowledge and belief, this is a true, correct, and complete return.

Signature	Title	Date
	Controller	10/11/2017

CBT-100
2016
Taxpayer
Information

020RV01161

NEW JERSEY CORPORATION BUSINESS TAX RETURN

For taxable years ending on or after July 31, 2016 through June 30, 2017

Taxable year beginning 01/01/2016 and ending 12/31/2016

DIVISION USE:
RP NP A____ R____

570-248-695/000 0400-1916-15 FAC 221100 VC N014

SOUTH CAROLINA ELECTRIC AND GAS COM CDV 856520

220 OPERATION WAY

CAYCE SC 29033-3701

STATE AND DATE OF INCORPORATION: SC 07191924

DATE AUTHORIZED TO DO BUSINESS IN NJ: 10312006

CORPORATION BOOKS ARE IN CARE OF: JAMES SWAN IV

CORPORATION BOOKS ARE AT: 220 OPERATION WAY CAYCE,

TELEPHONE NUMBER: 8032179000

DATE 10/11/2017 SIGNATURE CONTROLLER TITLE

PAID PREPARER'S SIGNATURE	ADDRESS	FEDERAL IDENTIFICATION NUMBER
FIRM'S NAME	ADDRESS	FEDERAL EMPLOYER'S IDENTIFICATION NUMBER

0230201010

CORPORATION BUSINESS TAX APPLICATION FOR EXTENSION OF TIME TO FILE WORKSHEET

CBT-200-TC

BEGINNING TAX YEAR 2016, YOU NEED TO PAY YOUR NEW JERSEY CORPORATION BUSINESS TAX ELECTRONICALLY

You need to pay the tax by one of these methods

1 **Electronic Check or Credit Card:** Visit www njtaxation org and select "Electronic Services "
2 **Electronic Funds Transfer (EFT):** To register visit www nj gov/treasury/revenue/eft1 shtml

If you do not have access to the internet, call our Customer Service Center at 609-292-6400 to make a payment

DO NOT CUT THIS PAGE - DO NOT MAIL - FOR REFERENCE ONLY

6D3307 1 000

Corporation Business Tax Application for Extension of Time to File Worksheet
CBT-200-TC

Beginning 01/01/2016 and ending 12/31/2016

N014 2016
570-248-695/000 SOUT
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
220 OPERATION WAY
CAYCE, SC 29033-3701

1	Estimated Corporation Business Tax	1	00
2	Installment Payment (50% of Line 1)	2	00
3	Key Corporation AMA	3	00
4	Tentative Professional Corporation Fee	4	00
5	Installment Payment for PC Fee (50% of Line 4)	5	00
6	Total Tax and Fee Due	6	2000.00
7	Less Payment to Date	7	2000.00
8	Balance Due (Line 6 minus Line 7)	8	00

Payments should be made electronically If not possible, paper checks should be mailed to New Jersey Division of Taxation, PO Box 666, Trenton, NJ 08646-0666 Include the Federal ID# and tax year

02302570248695000SOUT161208000000000000

CBT-100
2016
Return
Summary

020RV02161

NEW JERSEY CORPORATION BUSINESS TAX RETURN

SOUTH CAROLINA ELECTRIC AND GAS COM

VC	N014	A0010	10233647	A3018	0
FID	570248695000	A0011	2138963982	A3019	0
CBT	0400191615	A0012	15144833	A3020	0
BEG	01	A0013	55188382	A3021	0
END	12	A0014	215401652	A4001	0
INITR	0	A0015	6349958	A4002	6296983
1120S	0	A0016	6587833	A4003	0
INACT	1	A0017	230655590	A4J2f	0
FAC	221100	A0018	297298406	A4J2g	3015062430
PPFID	0	A0019	2736550	A4J2h	
FFEIN	0	A020c	431921192	A4031	0
P1001	78115022	A0021	0	A40R4	0
P1002	0	A0022	371874	A40R6	0
P1003	0	A0023	1368809	A4AGR	0
P104a	0	A0024	43614763	BB001	110056888
P104b	0	A0025	0	BE001	112818510
P1005	0	A0026	862060752	BB003	0
P1006	0	A0027	2168700594	BE003	0
P1007	0	A0028	-29736612	BB006	0
P1008	0	A0029	0	BE006	0
P1009	0	A0030	0	BB020	13725997344
P1010	0	A0031	0	BE020	15019055753
P1011	0	A0032	107851634	BB024	0
P1012	0	A033a	0	BE024	0
P112a	1	A033b	0	C0007	35789944
P1013	2000	A033c	0	C1003	3
P1014	0	A033d	0	C1005	296950000
P1015	2000	A0034	78115022	H008b	230657590
P1016	0	A0035	0	J201a	0
P1017	0	A0036	78115022	J201b	0
P1018	2000	A0037	0	J201c	0
P1019	2000	A2003	-420319	J201d	0
P119a	0	A3001	0	J201e	0
P119b	0	A3002	0	CDV	856520
P1020	0	A3003	0		
P1021	0	A3004	0		
P1022	0	A3005	0		
P1023	0	A3006	0		
P124C	0	A3007	0		
P124R	0	A3008	0		
A0001	2998699530	A3009	0		
A0002	1088310803	A3010	0		
A0003	1910388727	A3011	0		
A0004	0	A3012	0		
A0005	235401711	A3013	0		
A0006	20964105	A3014	0		
A0007	0	A3015	0		
A0008	0	A3016	0		
A0009	-38024208	A3017	0		

NEW JERSEY CORPORATION BUSINESS TAX RETURN

2016

CBT-100

FOR TAXABLE YEARS ENDING ON OR AFTER
JULY 31, 2016 THROUGH JUNE 30, 2017

Taxable year beginning 01/01/2016, and ending 12/31/2016

NAME AS SHOWN ON RETURN	FEDERAL ID NUMBER
SOUTH CAROLINA ELECTRIC AND GAS COMPANY	570-248-695/000

Check if applicable [ ] Initial return [ ] 1120-S filer [X] Inactive

1.	Entire net income from Schedule A, line 38 (if a net loss, enter zero)	1.	78,115,022
2.	Allocation factor from Schedule J, Non-allocating taxpayers enter 1.000000	2.	0.000000
3.	Allocated net income - Multiply line 1 by line 2. Non-allocating taxpayers must enter the amount from line 1	3.	0
4.	a) Total nonoperational income $ ____ (Schedule O, Part I) (see instruction 37)		
	b) Allocated New Jersey nonoperational income (Schedule O, Part III)	4b.	
5.	Total operational and nonoperational income (line 3 plus line 4b)	5.	
6.	Investment Company - Enter 40% of line 1	6.	
7.	Real Estate Investment Trust - Enter 4% of line 1	7.	
8.	Tax Base - Enter amount from line 5 or line 6 plus 4b, or line 7 plus 4b, whichever is applicable	8.	0
9.	Amount of Tax - Multiply line 8 by the applicable tax rate (see instruction 11(a))	9.	
10.	Tax Credits (from Schedule A-3) (see instruction 43)	10.	0
11.	TOTAL CBT TAX LIABILITY - line 9 minus line 10	11.	
12.	Alternative Minimum Assessment (Schedule AM, Part VI, line 5) [X] Check and enter zero if AMA paid by a Key Corporation (see instruction 23)	12.	0
13.	Tax Due (greater of line 11 or 12 or minimum tax due from Schedule A-GR or instruction 11(d))	13.	2,000
14.	Key Corporation AMA Payment (Form 401, Part II, line 5)	14.	
15.	Subtotal - (Sum of lines 13 and 14)	15.	2,000
16.	Installment Payment - (Only applies if line 13 is $500 - see instruction 44)	16.	
17.	Professional Corporation Fees (Schedule PC, line 5)	17.	0
18.	TOTAL TAX AND PROFESSIONAL CORPORATION FEES (sum of lines 15, 16, and 17)	18.	2,000
19.	Payments & Credits (see instruction 45)	19.	2,000
	a) Payments made by Partnerships on behalf of taxpayer (attach copies of all NJK-1's)	19a.	
	b) Refundable Tax Credits (see instruction 45(f))	19b.	
20.	Balance of Tax Due - line 18 minus line 19, 19a and 19b	20.	
21.	Penalty and Interest Due - (see instructions 7(e) and 46)	21.	
22.	Total Balance Due - line 20 plus line 21	22.	

23. If line 19 plus 19a plus 19b is greater than line 18 plus line 21, enter the amount of overpayment		$	DIVISION USE
24. Amount of Item 23 to be	Credited to 2017 return $	Refunded $	

NAME AS SHOWN ON RETURN: SOUTH CAROLINA ELECTRIC AND GAS COM
FEDERAL ID NUMBER: 570-248-695/000

SCHEDULE A

COMPUTATION OF ENTIRE NET INCOME (SEE INSTRUCTION 16)
EVERY CORPORATION MUST COMPLETE LINES 1 - 38 OF THIS SCHEDULE.

1.	Gross receipts or sales 2998699530. Less returns and allowances	1.	2,998,699,530
2.	Less: Cost of goods sold (Schedule A-2, line 8)	2.	1,088,310,803
3.	Gross profit - Subtract line 2 from line 1	3.	1,910,388,727
4.	Dividends	4.	
5.	Interest	5.	235,401,711
6.	Gross rents	6.	20,964,105
7.	Gross royalties	7.	
8.	Capital gain net income (attach separate Federal Schedule D)	8.	NONE
9.	Net gain or (loss) from Federal Form 4797 (attach Federal Form 4797)	9.	-38,024,208
10.	Other income (attach schedule) See Statement 1	10.	10,233,647
11.	TOTAL INCOME - Add lines 3 through 10	11.	2,138,963,982
12.	Compensation of officers (Schedule F)	12.	15,144,833
13.	Salaries and wages 55188382. Less jobs credit ______ Balance	13.	55,188,382
14.	Repairs (Do not include capital expenditures)	14.	215,401,652
15.	Bad debts	15.	6,349,958
16.	Rents	16.	6,587,833
17.	Taxes	17.	230,655,590
18.	Interest	18.	297,298,406
19.	Contributions	19.	2,736,550
20a.	Depreciation from Federal Form 4562 (attach copy) — 20a. 431,921,192		
20b.	Less depreciation claimed in Schedule A and elsewhere on return — 20b.	20c.	431,921,192
21.	Depletion	21.	
22.	Advertising	22.	371,874
23.	Pension, profit-sharing plans, etc.	23.	1,368,809
24.	Employee benefit programs	24.	43,614,763
25.	Domestic production activities deduction	25.	
26.	Other deductions (attach schedule) See Statement 1	26.	862,060,752
27.	TOTAL DEDUCTIONS - Add lines 12 through 26	27.	2,168,700,594
28.	Taxable income before net operating loss deductions and special deductions (line 11 less line 27 must agree with line 28, page 1 of the Unconsolidated Federal Form 1120, or the appropriate line item from the Federal Forms 1120-IC-DISC, 1120-FSC or 1120-A, whichever is applicable). (See instructions 8(b) and 16(c)).	28.	-29,736,612
	NEW JERSEY ADJUSTMENTS -- LINES 29 - 38 MUST BE COMPLETED ON THIS FORM		
29.	Interest on Federal, State, Municipal and other obligations not included in Item 5 above (see instruction 16(d))	29.	
30.	Related interest addback (Schedule G, Part I)	30.	
31.	New Jersey State and other states taxes deducted above (see instruction 16(f))	31.	NONE
32.	Depreciation and other adjustments from Schedule S (see instruction 42)	32.	107,851,634
33.	(a) Deduction for IRC Section 78 Gross-up not deducted at line 37 below	33a.	
	(b) Other deductions and additions. Explain on separate rider. (see instruction 16(h))	33b.	
	(c) Elimination of nonoperational activity (Schedule O, Part I)	33c.	
	(d) Interest and intangible expenses and costs addback (Schedule G, Part II)	33d.	
34.	Entire net income before net operating loss deduction and dividend exclusion (total of lines 28 through 33 inclusive)	34.	78,115,022
35.	Net operating loss deduction from Form 500	35.	
36.	Entire Net Income before dividend exclusion (line 34 minus line 35)	36.	78,115,022
37.	Dividend Exclusion from Schedule R, line 7. (see instruction 16(j))	37.	
38.	ENTIRE NET INCOME (line 36 minus line 37 - carry to page 1, line 1)	38.	78,115,022

NAME AS SHOWN ON RETURN	FEDERAL ID NUMBER
SOUTH CAROLINA ELECTRIC AND GAS COM	570-248-695/000

SCHEDULE A-1 NET OPERATING LOSS DEDUCTION AND CARRYOVER

NOTE: SCHEDULE A-1 HAS BEEN REPLACED BY FORM 500. NET OPERATING LOSSES MUST BE DETAILED ON FORM 500 WHICH IS AVAILABLE SEPARATELY. TO OBTAIN THIS FORM AND RELATED INFORMATION, REFER TO THE INDEX ON PAGE 14.

SCHEDULE A-2 COST OF GOODS SOLD (See Instruction 18)

1.	Inventory at beginning of year	1.	171,415,921
2.	Purchases	2.	5,268,408
3.	Cost of labor	3.	-420,319
4.	Additional section 263A costs	4.	
5.	Other costs (attach schedule) See Statement 2	5.	1,084,947,563
6.	Total - Add lines 1 through 5	6.	1,261,211,573
7.	Inventory at end of year	7.	172,900,770
8.	Cost of goods sold - Subtract line 7 from line 6. Enter here and on Schedule A, line 2	8.	1,088,310,803

SCHEDULE A-3 SUMMARY OF TAX CREDITS (See Instruction 19)

1.	Angel Investor Tax Credit from Form 321	1.	
2.	Grow NJ Tax Credit from Form 320	2.	
3.	Wind Energy Facility from Form 322	3.	
4.	Urban Transit Hub Tax Credit from Form 319	4.	
5.	Business Retention and Relocation Tax Credit from Form 316	5.	
6.	Neighborhood Revitalization State Tax Credit from Form 311	6.	
7.	Film Production Tax Credit from Form 318	7.	
8.	Sheltered Workshop Tax Credit from Form 317	8.	
9.	AMA Tax Credit from Form 315	9.	
10.	Economic Recovery Tax Credit from Form 313	10.	
11.	Effluent Equipment Tax Credit from Form 312	11.	
12.	HMO Assistance Fund Tax Credit from Form 310	12.	
13.	Small New Jersey-Based High-Technology Business Investment Tax Credit from Form 308	13.	
14.	New Jobs Investment Tax Credit from Form 304	14.	
15.	Manufacturing Equipment and Employment Investment Tax Credit from Form 305	15.	
16.	Research and Development Tax Credit from Form 306	16.	
17.	Recycling Equipment Tax Credit from Form 303	17.	
18.	Redevelopment Authority Project Tax Credit from Form 302	18.	
19.	EITHER: a) Urban Enterprise Zone Employee Tax Credit from Form 300 OR b) Urban Enterprise Zone Investment Tax Credit from Form 301	19.	
20.	Residential Economic Redevelopment and Growth Tax Credit from Form 323	20.	
21.	Other Tax Credits (see instruction 43(t))	21.	
22.	Total tax credits taken on this return - Add lines 1 through 21. Enter here and on page 1, line 10	22.	

ALL CORPORATIONS MUST COMPLETE THIS SCHEDULE AND SUBMIT IT WITH THEIR CBT-100 TAX RETURN

NAME AS SHOWN ON RETURN	FEDERAL ID NUMBER
SOUTH CAROLINA ELECTRIC AND GAS COM	570-248-695/000

SCHEDULE A-4 SUMMARY SCHEDULE (See Instruction 20)

Net Operating Loss Deduction and Carryover 1. Form 500, line 6 minus line 8	1.	0	6. Schedule J, Part II, line 1(h)	6.	
Interest and Intangible Costs and Expenses 2. Schedule G, Part I, line b	2.	6,296,983	**Net Operational Income Information** 7. Schedule O, Part III, line 31	7.	0
3. Schedule G, Part II, line b	3.	0	**Dividend Exclusion Information** 8. Schedule R, line 4	8.	
Schedule J Information 4. Schedule J, Part II, line 1(f)	4.	0	9. Schedule R, line 6	9.	0
5. Schedule J, Part II, line 1(g)	5.	3,015,062,430	**Schedule A-GR Information** 10. Schedule A-GR, line 6	10.	0

SCHEDULE A-5 FEDERAL IRC SECTION 199 ADJUSTMENT (See Instruction 21)

1. Federal Section 199 Domestic Production expensed in arriving at federal taxable income	1.	
2. Less: New Jersey Separate Entity Domestic Production allowed from Form 501	2.	
3. Net Section 199 adjustment - line 1 minus line 2. Include on Schedule A, line 33(b)	3.	

SCHEDULE I

State of New Jersey
Division of Taxation

CERTIFICATION OF INACTIVITY

For the period beginning 01/01 , 2016 and ending 12/31 , 2016

Corporation Name	Federal ID Number
SOUTH CAROLINA ELECTRIC AND GAS COMPANY	570-248-695/000

(NOTE: Attach this schedule to the taxpayer's CBT-100 or CBT-100S, whichever is applicable)

I certify that during the period covered by the attached tax return, the above named taxpayer had no business activities, no income, no assets, and additionally, in the case of a New Jersey S Corporation, made no distributions, and did not have any change in ownership.

Signature of Corporate Officer	Title	Date
	CONTROLLER	10/11/2017

INSTRUCTIONS

In lieu of completing the entire CBT-100 or CBT-100S tax return, an inactive corporation may complete this schedule and one of the following: pages 1 through 4 of the CBT-100 or pages 1 through 5 of the CBT-100S in order to fulfill its filing obligations with the State of New Jersey. Note: If using third party software the Taxpayer Information and Return Summary page must also be included. An inactive corporation is a corporation that, during the entire period covered by the tax return, did not conduct any business, did not have any income, receipts, or expenses, did not own any assets, and additionally, for New Jersey S corporations, did not make any distributions, and did not have any change in ownership.

This schedule and the applicable pages from the Corporation Business Tax Return must be filed annually by the taxpayer. The minimum tax liability and installment payment (if applicable) must be reported on page 1 of the Corporation Business Tax Return. If a balance due exists, taxpayers must submit payment with the appropriate Corporation Business Tax Payment Voucher, either CBT-100-V or CBT-100S-V.

Schedule I and page 1 of the Corporation Business Tax Return must be signed by an officer of the corporation who is authorized to attest to the truth of the statements contained therein.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

New Jersey CBT-100, Page 2 Detail

Sch A, Line 10 - Other Income

GAIN ON LAND SALES	
INCOME OR LOSS FROM OTHER PASSTHROUGH ENTITIES	-4,833,278.
MISCELLANEOUS INCOME WITHOUT DIFFERENCES	15,066,925.
Total	10,233,647.

Sch A, Line 26 - Other Deductions

Amortization	8,116,771.
Travel, meals and entertainment	1,001,437.
POLLUTION CONTROL	10,705,348.
INJURIES AND DAMAGES	5,807,027.
INSURANCE	7,158,823.
MERCHANDISING EXPENSES	1,031,448.
MISCELLANEOUS DEDUCTIONS	39,340,430.
MISCELLANEOUS DEDUCTIONS WITHOUT DIFFERENCES	51,659,518.
OFFICE SUPPLIES AND EXPENSES	20,537,993.
OUTSIDE SERVICES	16,406,895.
PIPELINE INTEGRITY	-17,084,713.
481A ADJUSTMENT	-4,228,547.
RESEARCH AND DEVELOPMENT	721,608,322.
Total	862,060,752.

SOUTH CAROLINA ELECTRIC and GAS COMPANY 57-0248695

New Jersey CBT-100, Page 3 Detail

Sch A-2, Line 5 - Other costs

ELECTRIC - DISTRIBUTION	15,271,035.
ELECTRIC - GENERAL	-2,620,344.
ELECTRIC - PRODUCTION	826,249,729.
ELECTRIC - SALES PROMOTION	6,663,922.
ELECTRIC - TRANSMISSION	9,288,573.
GAS - CUSTOMER ACCOUNTS	53,410,559.
GAS - DISTRIBUTION	9,133,565.
GAS - PRODUCTION	184,185,087.
GAS - TRANSMISSION	235.
OTHER COSTS	-16,634,798.
Total other COGS / COOP	1,084,947,563.

Statement 2

NEW YORK STATE 2016

Department of Taxation and Finance

General Business Corporation Franchise Tax Return

Tax Law - Article 9-A

CT-3

Caution: This form must be used **only** for tax periods beginning on or after January 1, 2016. If you use it for any prior periods, the return will **not** be processed and will **not** be considered timely filed. As a result, penalties and interest may be incurred *(see Form CT-1)*.

See instructions, Form CT-3-I, before completing return.

All filers must enter tax period: beginning 01-01-16 ending 12-31-16

Final return ☐ **Amended return** ☐

Employer identification number (EIN): 57-0248695	File number: AA4	Business telephone number: 803-217-9000	If you claim an overpayment, mark an *X* in the box: X
Legal name of corporation: SOUTH CAROLINA ELECTRIC and GAS C		Trade name/DBA:	
Mailing name *(if different from legal name above)*: c/o		State or country of incorporation: SC	
Mailing address number and street or PO box: 220 OPERATION WAY		Date of incorporation: 07-19-24	Foreign corporations: date began business in NYS: 10-31-06
City: CAYCE	State ZIP code: SC 29033-3701	Country *(if not United States)*:	*For office use only*
Principal business activity in NYS: UTILITY	NAICS business code number *(from NYS Pub 910)*: 221100		
If address/phone above is new, mark an *X* in the box ☐	If you need to update your address or phone information for corporation tax, or other tax types, you can do so online. See *Business information* in Form CT-1.		

A. Pay amount shown on Part 2, line 23. Make payable to: ***New York State Corporation Tax***
Attach your payment here. *(Detach all check stubs; see instructions for details.)* A | Payment enclosed:

B. Are you subject to the metropolitan transportation business tax (MTA surcharge)? *(see instructions; mark an X in the appropriate box)* . . . . . B Yes ☐ No X

C. If you are disclaiming tax liability in New York State based on Public Law 86-272, mark an ***X*** in the box *(see instructions)* . . . . . C ☐

Third - party designee *(see instructions)*	
Yes ☐ No X	Designee's name *(print)*:
Designee's phone number:	
Designee's e-mail address:	PIN:

Certification: I certify that this return and any attachments are to the best of my knowledge and belief true, correct, and complete.

Authorized person	Printed name of authorized person: JAMES SWAN IV	Signature of authorized person: [signature]	Official title: CONTROLLER	
	E-mail address of authorized person: jswan@scana.com		Telephone number: 803-217-9000	Date: 10-11-17
Paid preparer use only *(see instr.)*	Firm's name *(or yours if self-employed)*:	Firm's EIN:	Preparer's PTIN or SSN:	
	Signature of individual preparing this return:	Address:		
	E-mail address of individual preparing this return:	Preparer's NYTPRIN or	Excl. code	Date

See instructions for where to file.

Content of Form CT-3

567001161062

6D3511 1.000

Part 1 – General corporate information

Section A – Qualification for preferential tax rates

If you are a corporation as identified in this section and qualify for preferential tax rates, mark an *X* in the boxes that apply to you *(see instructions)*.

1 A qualified emerging technology company (QETC) for purposes of the lower tax rates, capital base tax cap, and fixed dollar minimum tax amounts • 1 ☐

2 A qualified New York manufacturer based on the principally engaged test for purposes of the lower business income base tax rate and fixed dollar minimum tax amounts • 2 ☐

3 A qualified New York manufacturer based on the principally engaged test for purposes of the lower capital base tax rate and capital base tax cap • 3 ☐

4 A qualified New York manufacturer based on the significant employment and property test for purposes of the lower tax rates, capital base tax cap, and fixed dollar minimum tax amounts • 4 ☐

5 Claiming cooperative housing corporation status for the lower capital base tax rate • 5 ☐

6 A small business eligible for the capital base tax exception • 6 ☐

If you marked this box, complete line 6a; also mark the box at line 6b or 6c, if applicable.

6a Total capital contributions • 6a

6b Small business taxpayers only: you are also a QETC • 6b ☐

6c Small business taxpayers only: you are also a qualified New York manufacturer • 6c ☐

7 A qualified entity of a New York State innovation hot spot that operates solely within such New York State innovation hot spot, and you have elected to be subject only to the fixed dollar minimum tax base • 7 ☐

Section B – New York State information *(see instructions)*

1 Number of New York State employees • 1

2 Wages paid to New York State employees • 2

3 Number of business establishments in New York State • 3

4 If you have an interest in, or have rented, real property in New York State, mark an *X* in the box and complete lines 4a and 4b *(if multiple counties see instructions)* • 4 ☐

4a The real property's county • 4a

4b The real property's value or rent • 4b

5 If you are claiming an exception to the related member expense addback under Tax Law §208.9(o)(2)(B), mark an *X* in the box • 5 ☐

5a If you marked the line 5 box, use line 5a to report the applicable exception number (1-4) and the amount of royalty payments. 5a • Number • Amount

6 If you are not protected by Public Law 86-272 and are subject to tax **solely** as a result of deriving receipts in New York State, mark an *X* in the box • 6 ☐

Section C – Filing information

1 **Federal return filed** – you must mark an *X* in one box and attach a complete copy of your federal return

1120 • ☐ 1120 consolidated • ☒ 1120-REIT or 1120-RIC ☐ 1120S • ☐ 1120F • ☐ 1120-H ☐

2 **Amended return** – If you marked the amended return box on page 1, then for any item(s) that apply, mark an *X* in the box and attach documentation: Failure to meet investment capital holding period • ☐

Final federal determination • ☐ • Date of determination ____ NOL carryback • ☐ Capital loss carryback • ☐ 1139 • ☐ 1120X • ☐

2a Enter the tax due amount from your most recently filed New York State return for this tax period • 2a

3 **Required attachments** – For all forms, other than tax credit claim forms, that are attached to this return, mark an *X* in the applicable box(es)

CT-3.1 • ☐ CT-3.2 • ☐ CT-3.3 • ☐ CT-3.4 • ☐ CT-60 • ☐ CT-225 • ☐ Other *(identify)*: ________ • ☐

4 If you are claiming tax credits, enter the number of tax credit forms attached to this return. Where multiple forms are filed for the same credit, count **each** form filed • 4

5 If you filed federal Form 1120F and you have effectively connected income (ECI), mark an *X* in the box • 5 ☐

567002161062

Part 2 – Computation of balance due or overpayment

Largest of three tax bases, minus credits

Line	Description	Box	Amount	Box	Amount
1a	Business income base tax *(from Part 3, line 20)*	1a	NONE		
1b	Capital base tax *(from Part 4, line 15; see instructions)*	1b	NONE		
1c	Fixed dollar minimum tax *(see instr)* New York receipts 0.	1c	25.		
2	Tax due *(enter the amount from line 1a, 1b, or 1c, whichever is largest; see instructions)*			2	25.
3	Tax credits used *(from Part 7, line 2; see instructions)*			3	
4	Tax due after credits *(subtract line 3 from line 2; if line 3 is more than line 2, enter 0)*			4	25.
5					
6	**Mandatory first installment (MFI) removed; see instructions**				
7					

Penalties and interest

Line	Description	Box	Amount	Box	Amount
8	Estimated tax penalty *(see instructions; if Form CT-222 is attached, mark an X in the box)* ☐	8			
9	Interest on late payment *(see instructions)*	9			
10	Late filing and late payment penalties *(see instructions)*	10			
11	Total penalties and interest *(add lines 8, 9, and 10)*			11	

Voluntary gifts/contributions *(see instructions)*

Line	Description	Box	Amount	Box	Amount
12a	Return a Gift to Wildlife	12a			
12b	Breast Cancer Research and Education Fund	12b			
12c	Prostate Cancer Research, Detection, and Education Fund	12c			
12d	9/11 Memorial	12d			
12e	Volunteer Firefighting & EMS Recruitment Fund	12e			
12f	Veterans Remembrance	12f			
12g	Women's Cancers Education and Prevention Fund	12g			
13	Total voluntary gifts/contributions *(add lines 12a through 12g)*			13	

Total amount due

Line	Description	Box	Amount
14	Add lines 4, 11, and 13	14	25.

Prepayments

Line	Description	Box	Amount	Box	Amount
15	Mandatory first installment	15			
16	Second installment *(from Form CT-400)*	16			
17	Third installment *(from Form CT-400)*	17			
18	Fourth installment *(from Form CT-400)*	18			
19	Payment with extension request *(from Form CT-5, line 5)*	19			
20	Overpayment credited from prior years Period	20	8,875.		
21	Overpayment credited from CT-3-M Period	21			
22	Total prepayments *(add lines 15 through 21; see instructions)*			22	8,875.

Payment due or overpayment to be credited/refunded

Line	Description	Box	Amount	Box	Amount
23	Balance due *(If line 22 is less than line 14, subtract line 22 from line 14 and enter the result here. This is the amount due; enter **payment amount** on page 1, line A.)*			23	
24	Overpayment *(If line 22 is more than line 14, subtract line 14 from line 22. This is your overpayment; enter the result here and see instructions.)*			24	8,850.
25	Amount of overpayment to be credited to next period *(see instructions)*			25	
26	Balance of overpayment available *(subtract line 25 from line 24; see instructions)*			26	8,850.
27	Amount of overpayment to be credited to Form CT-3-M			27	
28	Balance of overpayment to be refunded *(subtract line 27 from line 26; see instructions)*			28	8,850.
29	Unused tax credits to be refunded *(see instructions)*	29			
30	Unused tax credits applied to next period	30			

Part 3 – Computation of tax on business income base

1	Federal taxable income (FTI) before net operating loss (NOL) and special deductions *(see instructions)* •	1	-27,000,062.
2	Additions to FTI *(from Form CT-225, line 5)* •	2	
3	Add lines 1 and 2 •	3	-27,000,062.
4	Subtractions from FTI *(from Form CT-225, line 10)* •	4	
5	Subtract line 4 from line 3 •	5	-27,000,062.
6	Subtraction modification for qualified banks *(from Form CT-3.2, Schedule A, line 1; see instructions)* •	6	
7	Entire net income (ENI) *(subtract line 6 from line 5)* •	7	-27,000,062.
8	Investment and other exempt income *(from Form CT-3.1, Schedule D, line 1)* •	8	
9	Subtract line 8 from line 7 •	9	-27,000,062.
10	Excess interest deductions attributable to investment income, investment capital, and other exempt income *(from Form CT-3.1, Schedule D, line 2)* •	10	
11	Business income *(add lines 9 and 10)* •	11	-27,000,062.
12	Addback of income previously reported as investment income *(from Form CT-3.1, Schedule F, line 6; if zero, enter 0; see instructions)* •	12	
13	Business income after addback *(add lines 11 and 12)* •	13	-27,000,062.
14	Business apportionment factor *(from Part 6, line 55)* •	14	NONE
15	Apportioned business income after addback *(multiply line 13 by line 14)* •	15	NONE
16	Prior net operating loss conversion subtraction *(from Form CT-3.3, Schedule C, line 4)* •	16	
17	Subtract line 16 from line 15 •	17	NONE
18	NOL deduction *(from Form CT-3.4, line 6)* •	18	
19	Business income base *(subtract line 18 from line 17)* •	19	NONE
20	Business income base tax *(multiply line 19 by the appropriate business income tax rate from the tax rates schedule in Form CT-3-I; enter here and on Part 2, line 1a; see instructions)* •	20	NONE

Note: If you make any entry on line 2, 4, 6, 8, 10, 12, 16, or 18, you **must** complete and file the appropriate attachment form, or any tax benefit claimed may be disallowed, or there may be a delay in receiving such benefit.

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Part 4 – Computation of tax on capital base *(see instructions)*

		A Beginning of year	B End of year	C Average value
1	Total assets from federal return	13725997344.	15019055753.	14372526549.
2	Real property and marketable securities included on line 1			
3	Subtract line 2 from line 1	13725997344.	15019055753.	14372526549.
4	Real property and marketable securities at fair market value			
5	Adjusted total assets *(add lines 3 and 4)*	13725997344.	15019055753.	14372526549.
6	Total liabilities	8,702,959,438.	9,680,479,622.	9,191,719,530.

7	Total net assets *(subtract line 6, column C, from line 5, column C)*	7	5,180,807,019.
8	Investment capital *(from Part 5, line 19; if zero or less, enter **0**)*	8	
9	Business capital *(subtract line 8 from line 7)*	9	5,180,807,019.
10	Addback of capital previously reported as investment capital *(from Part 5, line 20, column C; if zero or less, enter 0)*	10	
11	Total business capital *(add lines 9 and 10)*	11	5,180,807,019.
12	Business apportionment factor *(from Part 6, line 55)*	12	NONE
13	Apportioned business capital *(multiply line 11 by line 12)*	13	NONE
14	New small business *(if in first two tax years, mark an **X** in one box)* Year one ☐ Year two ☐		
15	Capital base tax *(multiply line 13 by the appropriate capital base tax rate from the tax rates schedule in Form CT-3-I; enter here and on Part 2, line 1b)*	15	NONE

Part 5 – Computation of investment capital for the current tax year *(see instructions)*

		A Average fair market value as reported	B Liabilities attributable to column A amount	C Net average value *(column A – column B)*
16	Total capital that generates income claimed to not be taxable by New York under the U.S. Constitution *(from Form CT-3.1, Schedule E, line 1)*			
17	Total of stocks **actually** held for more than one year *(from Form CT-3.1, Schedule E, line 2)*			
18	Total of stocks **presumed** held for more than one year *(from Form CT-3.1, Schedule E, line 3)*			

19	Total investment capital for the current year *(Add column C lines 16, 17, and 18; enter the result here and on Part 4, line 8. If zero or less, enter 0.)*	19	

Addback of capital previously reported as investment capital

		A Average fair market value as previously reported	B Liabilities attributable to column A amount as previously reported	C Net average value as previously reported *(column A - column B)*
20	Total of stocks previously presumed held for more than one year, but did **not** meet the holding period *(from Form CT-3.1, Schedule F, line 1; enter here and on Part 4, line 10)*			

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Part 6 - Computation of business apportionment factor *(see instructions)*

Mark an *X* in this box only if you have **no receipts** required to be included in the denominator of the apportionment factor *(see instr.)* • ☐

		A - New York State	B - Everywhere
Section 210-A.2			
1 Sales of tangible personal property •	1	NONE	3015062430.
2 Sales of electricity •	2		
3 Net gains from sales of real property •	3		
Section 210-A.3			
4 Rentals of real and tangible personal property •	4		
5 Royalties from patents, copyrights, trademarks, and similar intangible personal property •	5		
6 Sales of rights for certain closed-circuit and cable TV transmissions of an event •	6		
Section 210-A.4			
7 Sale, licensing, or granting access to digital products •	7		

Section 210-A.5(a)(1) – Fixed percentage method for qualified financial instruments (QFIs)

8 To make this irrevocable election, mark an *X* in the box *(see instructions)* • 8 ☐

Section 210-A.5(a)(2) – Mark an *X* in each box that is applicable *(see line 8 instructions)*

		A - New York State	B - Everywhere
Section 210-A.5(a)(2)(A)			
9 Interest from loans secured by real property •	9		
10 Net gains from sales of loans secured by real property •	10		
11 Interest from loans **not** secured by real property (QFI • ☐) •	11		
12 Net gains from sales of loans **not** secured by real property (QFI • ☐) •	12		
Section 210-A.5(a)(2)(B) (QFI • ☐)			
13 Interest from federal debt •	13		
14			
15 Interest from NYS and its political subdivisions debt •	15		
16 Net gains from federal, NYS, and NYS political subdivisions debt •	16		
17 Interest from other states and their political subdivisions debt •	17		
18 Net gains from other states and their political subdivisions debt •	18		
Section 210-A.5(a)(2)(C) (QFI • ☐)			
19 Interest from asset-backed securities and other government agency debt •	19		
20 Net gains from government agency debt or asset-backed securities sold through an exchange •	20		
21 Net gains from all other asset-backed securities •	21		
Section 210-A.5(a)(2)(D) (QFI • ☐)			
22 Interest from corporate bonds •	22		
23 Net gains from corporate bonds sold through broker/dealer or licensed exchange •	23		
24 Net gains from other corporate bonds •	24		
Section 210-A.5(a)(2)(E)			
25 Net interest from reverse repurchase and securities borrowing agreements •	25		
Section 210-A.5(a)(2)(F)			
26 Net interest from federal funds •	26		
Section 210-A.5(a)(2)(I) (QFI • ☐)			
27 Net income from sales of physical commodities •	27		
Section 210-A.5(a)(2)(J) (QFI • ☐)			
28 Marked to market net gains •	28		
Section 210-A.5(a)(2)(H) (QFI • ☐) **210-A.5(a)(2)(G)** (QFI • ☐)			
29 Interest from other financial instruments •	29		
30 Net gains and other income from other financial instruments •	30		

Part 6 – Computation of business apportionment factor *(continued)*

		A - New York State	B - Everywhere
Section 210-A.5(b)			
31 Brokerage commissions	31		
32 Margin interest earned on behalf of brokerage accounts	32		
33 Fees for advisory services for underwriting or management of underwriting	33		
34 Receipts from primary spread of selling concessions	34		
35 Receipts from account maintenance fees	35		
36 Fees for management or advisory services	36		
37 Interest from an affiliated corporation	37		
Section 210-A.5(c)			
38 Interest, fees, and penalties from credit cards	38		
39 Service charges and fees from credit cards	39		
40 Receipts from merchant discounts	40		
41 Receipts from credit card authorizations and settlement processing	41		
42 Other credit card processing receipts	42		
Section 210-A.5(d)			
43 Receipts from certain services to investment companies	43		
Section 210-A.6			
44 Receipts from railroad and trucking business	44		
Section 210-A.6-a			
45 Receipts from the operation of vessels	45		
Section 210-A.7			
46 Receipts from air freight forwarding	46		
47 Receipts from other aviation services	47		
Section 210-A.8			
48 Advertising in newspapers or periodicals	48		
49 Advertising on television or radio	49		
50 Advertising via other means	50		
Section 210-A.9			
51 Transportation or transmission of gas through pipes	51		
Section 210-A.10			
52 Receipts from other services/activities not specified	52		
Section 210-A.11			
53 Discretionary adjustments	53		
Total receipts			
54 Add lines 1 through 53 in columns A and B	54	NONE	3,015,062,430.

Calculation of business apportionment factor

55 New York State business apportionment factor *(divide line 54, column A by line 54, column B and enter the result here; round to the fourth decimal place; if 100% in New York State, enter as* **1.0000***)* . . . • 55 NONE

Enter line 55 on Part 3, *Computation of tax on business income base*, line 14; and on Part 4, *Computation of tax on capital base*, line 12.

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Part 7 – Summary of tax credits claimed

1 Have you been convicted of an offense, or are you an owner of an entity convicted of an offense, defined in New York State Penal Law, Article 200 or 496, or section 195.20? *(see Form CT-1; mark an X in one box)* . . . . 1 Yes ☐ No [X]

Enter in the appropriate box below the amount of each tax credit **used** to reduce the tax due shown on Part 2, line 2, and attach the corresponding properly completed claim form. The amount of credit to enter is computed on each credit form and carried to this section.

CT-37		CT-605		DTF-622	
CT-40		CT-606		DTF-624	
CT-41		CT-607		DTF-630	
CT-43		CT-611		Other credits	
CT-44		CT-611.1			
CT-46		CT-611.2			
CT-47		CT-612			
CT-236		CT-613			
CT-238		CT-631			
CT-239		CT-633			
CT-241		CT-634			
CT-242		CT-635			
CT-243		CT-636			
CT-246		CT-637			
CT-248		CT-638			
CT-249		CT-639			
CT-250		CT-640			
CT-259		CT-641			
CT-261		CT-642			
CT-501		CT-643			
CT-601		CT-644			
CT-602		CT-645			
CT-603		CT-646			
CT-604		DTF-621			

2 Total tax credits claimed above *(enter here and on Part 2, line 3; attach appropriate form for each credit claimed)* 2

3 Total tax credits claimed that are refund eligible *(see instructions)* 3

4a If you claimed the QEZE tax reduction credit and you had a 100% zone allocation factor, mark an *X* in the box 4a

4b If you claimed the tax-free NY area tax elimination credit, and you had a 100% area allocation factor, mark an *X* in the box. 4b

4c If you claimed the tax-free NY area excise tax on telecommunications credit and you had a 100% area allocation factor, mark an *X* in the box 4c

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FORMS (TAX)

FORM NUMBER

STATE 1120

JURISDICTION

PENNSYLVANIA

MONTH

YEAR

2016

TYPE

INCOME

COMPANY

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

R pennsylvania DEPARTMENT OF REVENUE
Form PA-8453-C

PENNSYLVANIA CORPORATE NET INCOME TAX DECLARATION FOR A STATE e-file REPORT

2016

For calendar year 2016 or tax year beginning, 01/01 2016, ending, 12/31 20 ~~16~~

FEDERAL EMPLOYER IDENTIFICATION NUMBER (FEIN) 570248695

Name of Corporation
SOUTH CAROLINA ELECTRIC AND GAS COMPANY

Address	City	State	ZIP	Revenue ID Number
220 OPERATION WAY	CAYCE	SC	29033-370	1000236565

PART I TAX REPORT INFORMATION (Whole dollars only.)

1. Income or Loss from Federal Return on a Separate Company Basis (From RCT-101, Section B, Line 1)	1.	-27,000,062.
2. PA Taxable Income or Loss (From RCT-101, Section B, Line 12)	2.	NONE
3. PA Corporate Net Income Tax (From RCT-101, Section B, Line 13)	3.	NONE

PART II DECLARATION OF OFFICER (See instructions.) **Keep a copy of the corporation's tax report, RCT-101.**

4a. ☐ I consent that the corporation's refund check can be mailed directly to the address provided on the RCT-101.

4b. ☐ I do not want a refund mailed to the corporation, or the corporation is not receiving a refund.

4c. ☐ I authorize (1) the PA Department of Revenue and its designated financial institution to initiate an electronic funds withdrawal entry to my financial institution account designated in the electronic portion of my 2016 Pennsylvania Corporate Net Income Tax Report for payment of my state taxes owed; and (2) my financial institution to debit the entry to my account. I also authorize the financial institutions involved in the processing of my electronic payment of taxes to receive confidential information necessary to answer inquiries and resolve issues related to my payment. I can revoke this authorization by notifying the PA Department of Revenue no later than two business days prior to the payment date. I understand notification must be made by calling 717-783-6277.

If I filed a balance-due report, I understand if the PA Department of Revenue does not receive full and timely payment of my tax liability, I remain liable for the tax due and all applicable interest and penalties. If I filed a joint federal and state tax return/report and there is an error on my federal return, I understand my state report will be rejected.

Under penalties of perjury, I declare I am an officer of the above-named corporation and the information I provided to my electronic return originator (ERO) and/or transmitter and the amounts in Part I above agree with the amounts on the corresponding lines of the corporation's 2016 Pennsylvania Corporate Net Income Tax Report. To the best of my knowledge and belief, the corporation's report is true, correct and complete. I consent to my ERO and/or transmitter sending the corporation's report and accompanying schedules and statements to the Internal Revenue Service (IRS) and subsequently by the IRS to the PA Department of Revenue. I also consent to the PA Department of Revenue sending my ERO and/or transmitter, through the IRS, an acknowledgment of receipt of transmission, an indication of whether or not the corporation's report is accepted and, if rejected, the reason(s) for rejection.

SIGN HERE ▶

Signature of Officer	Date	Title	Social Security number
[signature]	10/11/2017	CONTROLLER	

Address	City	State	ZIP
220 OPERATION WAY	CAYCE	SC	29033-370

PART III DECLARATION OF ELECTRONIC RETURN ORIGINATOR (ERO) AND PAID PREPARER (See instructions.)

I declare I have reviewed the above-named corporation's report, and the entries on Form PA 8453-C are complete and correct to the best of my knowledge and belief. I obtained the corporate officer's signature on this form before submitting the report to the PA Department of Revenue, provided the corporate officer a copy of all forms and information to be filed with the PA Department of Revenue and followed all other requirements specified by the PA Department of Revenue and in IRS Pub. 3112, IRS e-file Application and Participation, and Pub. 4163, Modernized e-File (MeF) Information for Authorized IRS e-file Providers of forms 1120/1120S. If I am also the preparer, under penalties of perjury, I declare I examined the above-named corporation's report, accompanying schedules and statements, and to the best of my knowledge and belief they are true, correct and complete. I understand I am required to keep this form and the supporting documents for three years.

ERO's USE ONLY	ERO's Signature ▶	Date	Check if also paid preparer ☒	Check if self-employed ☐	ERO's SSN or PTIN
	Firm's name (or yours if self-employed), address and ZIP code ▶				EIN
				Telephone Number	

Under penalties of perjury, I declare I examined the above-named corporation's report, accompanying schedules and statements, and to the best of my knowledge and belief they are true, correct and complete.

PAID PREPARER'S USE ONLY	Preparer's Signature ▶	Date	Check if self-employed ☐	Preparer's SSN or PTIN
	Firm's name (or yours if self-employed), address and ZIP code ▶		Telephone Number	

Electronic Return Originators (EROs) and paid preparers must retain this form and supporting documents for three years.

DO NOT SUBMIT THIS FORM TO THE PA DEPARTMENT OF REVENUE UNLESS REQUESTED TO DO SO.

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DEPARTMENT USE ONLY

RCT-101 (08-16) **PAGE 1 OF 4**

PA CORPORATE NET INCOME TAX REPORT 2016

IRS Filing Type A = 1120 B = 1120S C = Other A

STEP A

Tax Year Beginning 01012016 Tax Year Ending 12312016

STEP B

Amended Report	N	52-53 Week Filer	N	First Report	N	File Period Change	N
Federal Extension Granted	Y	Address Change	N	KOZ/EIP/SDA Credit	N	S Corp Taxable Built-in Gains	N
		Change Fed Group	N	Royalty/Related Interest Add-Back (Act 52 of 2013)	N	Regulated Inv. Co./ Sub Paragraph 18	N

STEP C

Revenue ID 1000236565 Parent Corporation EIN 570784499
Federal EIN 570248695
Business Activity Code 221100
Corporation Name SOUTH CAROLINA ELECTRIC AND GAS COMPANY
Address Line 1 220 OPERATION WAY
Address Line 2
City CAYCE Province
State SC Country Code
ZIP 29033-370 Foreign Postal Code

STEP D: PA CORPORATE NET INCOME TAX

USE WHOLE DOLLARS ONLY

	A. Tax Liability from Page 2 (can not be less than zero)	B. Estimated Payments & Credits on Deposit	C. Restricted Credits	STEP E: Payment Due/Overpayment Calculation: A minus B minus C See Instructions.
CNI	0	676	0	-676

STEP F: Transfer/Refund Method (See instructions.)

E-File Opt Out (See instructions.) N

676 Transfer: Amount to be credited to the next tax year after offsetting all unpaid liabilities.

0 Refund: Amount to be refunded after offsetting all unpaid liabilities.

STEP G: Corporate Officer (Must sign affirmation below)

NAME JAMES SWAN IV
PHONE 8032179000
EMAIL JSWAN@SCANA.COM

FORM 1062
BARCODE 0000

6Y4623 3.000

I affirm under penalties prescribed by law, this report, including any accompanying schedules and statements, has been examined by me and to the best of my knowledge and belief is a true, correct and complete report. If this report is an amended report, the taxpayer hereby consents to the extension of the assessment period for this tax year to one year from the date of filing of this amended report or three years from the filing of the original report, whichever period last expires, and agrees to retain all required records pertaining to that tax and tax period until the end of the extended assessment period, regardless of any statutory provision providing for a shorter period of retention. For purposes of this extension, an original report filed before the due date is deemed filed on the due date. I am authorized to execute this consent to the extension of the assessment period.

Corporate Officer Signature	Date
Jas E Swan IV	

Form **7004**
(Rev. December 2016)
Department of the Treasury
Internal Revenue Service

Application for Automatic Extension of Time To File Certain Business Income Tax, Information, and Other Returns

▶ File a separate application for each return.
▶ Information about Form 7004 and its separate instructions is at *www.irs.gov/form7004*.

OMB No. 1545-0233

Print or Type

Name: SCANA CORPORATION
Identifying number: 57-0784499
Number, street, and room or suite no. (If P.O. box, see instructions.): 220 OPERATION WAY
City, town, state, and ZIP code (If a foreign address, enter city, province or state, and country (follow the country's practice for entering postal code)): CAYCE, SC 29033-3701

Note: File request for extension by the due date of the return for which the extension is granted. See instructions before completing this form.

Part I **Automatic Extension for C Corporations With Tax Years Ending December 31.** See instructions.

1a Enter the form code for the return listed below that this application is for 1 2

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part II **Automatic Extension for Certain Estates and Trusts.** See instructions.

b Enter the form code for the return listed below that this application is for . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1041 (estate other than a bankruptcy estate)	04	Form 1041 (trust)	05

Part III **Automatic Extension for Entities Not Using Part I, II, or IV.** See instructions.

c Enter the form code for the return listed below that this application is for . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 706-GS(D)	01	Form 1120-ND (section 4951 taxes)	20
Form 706-GS(T)	02	Form 1120-PC	21
Form 1041 (bankruptcy estate only)	03	Form 1120-POL	22
Form 1041-N	06	Form 1120-REIT	23
Form 1041-QFT	07	Form 1120-RIC	24
Form 1042	08	Form 1120S	25
Form 1065	09	Form 1120-SF	26
Form 1065-B	10	Form 3520-A	27
Form 1066	11	Form 8612	28
Form 1120	12	Form 8613	29
Form 1120-C	34	Form 8725	30
Form 1120-F	15	Form 8804	31
Form 1120-FSC	16	Form 8831	32
Form 1120-H	17	Form 8876	33
Form 1120-L	18	Form 8924	35
Form 1120-ND	19	Form 8928	36

Part IV **Automatic Extension for C Corporations With Tax Years Ending June 30.** See instructions.

d Enter the form code for the return listed below that this application is for . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part V All Filers Must Complete This Part

2 If the organization is a foreign corporation that does not have an office or place of business in the United States, check here . . . ▶ ☐

3 If the organization is a corporation and is the common parent of a group that intends to file a consolidated return, check here . . . ▶ ☒

If checked, attach a statement listing the name, address, and Employer Identification Number (EIN) for each member covered by this application.

4 If the organization is a corporation or partnership that qualifies under Regulations section 1.6081-5, check here . . ▶ ☐

5a The application is for calendar year 20 16 , or tax year beginning ________, 20 ___, and ending ________, 20 ___

b **Short tax year.** If this tax year is less than 12 months, check the reason: ☐ Initial return ☐ Final return ☐ Change in accounting period ☐ Consolidated return to be filed ☐ Other (see instructions - attach explanation)

6	Tentative total tax . . .	6	6,000,000.
7	Total payments and credits (see instructions) . . .	7	6,000,000.
8	Balance due. Subtract line 7 from line 6 (see instructions) . . .	8	

SCANA CORPORATION 57-0784499

Form 7004 - Affiliated Group Members

Name	Employer ID	Name	Employer ID
SCANA SERVICES INC	57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695
SOUTH CAROLINA FUEL CO INC	57-0691209	SC GENERATING COMPANY INC	57-0784498
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908	SCANA ENERGY MARKETING INC	57-0850977
SERVICECARE INC	57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	56-2128483
CLEAN ENERGY ENTERPRISES INC	56-1078443	PSNC BLUE RIDGE CORPORATION	56-1791764
PSNC CARDINAL PIPELINE COMPANY	56-1955423	SCANA CORPORATE SECURITY SERVICES INC	20-0989017

Statement 1

1010016280

REVENUE ID 1000236565
TAX YEAR END 12312016 NAME SOUTH CAROLINA ELECTRIC AN

RCT-101 (08-16) **PAGE 2 OF 4 PA CORPORATE NET INCOME TAX REPORT 2016**

SECTION A: BONUS DEPRECIATION

USE WHOLE DOLLARS ONLY

(Include REV-799, Schedule C-3, if claiming bonus depreciation.)

1. Current year federal depreciation of 168k prop.	1	0
2. Current year adjustment for disposition of 168k prop.	2	0
3. Other adjustments.	3	0

SECTION B: PA CORPORATE NET INCOME TAX

1. Income or loss from federal return on a separate-company basis.	1	-27000062
2. DEDUCTIONS:		
2A. Corporate dividends received (from REV-798, Schedule C-2, Line 6).	2A	0
2B. Interest on U.S. securities (GROSS INTEREST minus EXPENSES).	2B	0
2C. Current yr. addtl. PA deprec. plus adjust. for sale (REV-799, Sched. C-3, Col. H; must include REV-799).	2C	0
2D. Other (from REV-860, Schedule OD) See instructions.	2D	365981990
TOTAL DEDUCTIONS - Add Lines 2A through 2D and enter the result on Line 2.	2	365981990
3. ADDITIONS:		
3A. Taxes imposed on or measured by net income (from REV-860, Schedule C-5, Line 6).	3A	0
3B. Employment incentive payment credit adjustment (Include Schedule W).	3B	0
3C. Current year bonus depreciation (from REV-799, Sched. C-3, Col. C; must include REV-799).	3C	0
3D. Intangible expense or related interest expense (REV-802, Sched. C-6, Line 11; must include REV-802).	3D	0
3E. Other (from REV-860, Schedule OA) See instructions.	3E	473833624
TOTAL ADDITIONS - Add Lines 3A through 3E and enter the result on Line 3.	3	473833624
4. Income or loss with Pennsylvania adjustments (Line 1 minus Line 2 plus Line 3).	4	80851572
5. Total nonbusiness income or loss (from REV-934, Column C, Total; must include REV-934).	5	0
6. Income or loss to be apportioned (Line 4 minus Line 5).	6	80851572
7. Apportionment (from Schedule C-1, 1C, or 2C if using Special Apportionment).	7	0.000000
8. Income or loss apportioned to PA (Line 6 times Line 7).	8	0
9. Nonbusiness income or loss allocated to PA (from REV-934, Column A, Total; must include REV-934).	9	0
10. PA taxable income or loss after apportionment (Line 8 plus Line 9).	10	0
11. Total net operating loss deduction (from RCT-103, Part A, Line 4).	11	0
12. PA taxable income or loss (Line 10 minus Line 11).	12	0
13. PA corporate net income tax (Line 12 times 0.0999). If Line 12 is less than zero, enter "0".	13	0
14. Less: Credit for tax paid by affiliate(s) for intangible expense or related interest expense (from REV-803, Sched. C-7, Line 9; must include REV-803).	14	0
15. Tax Due (Line 13 minus Line 14.)	15	0

SCHEDULE C-1: Apportionment Schedule For **Corporate Net Income Tax** (Include Form RCT-106.) *

Sales Factor					Special Apportionment		
Sales - PA	1A	NONE	1C	0	Numerator	2A	0
Sales - Total	1B	3015062430			Denominator	2B	0
					Apportionment Proportion	2C	0

6Y4664 4.000

* Refer to the CT-1 PA Corporation Tax Instructions, REV-1200, found at www.revenue.pa.gov.

1010016280

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1010016380

REVENUE ID 1000236565
TAX YEAR END 12312016 NAME SOUTH CAROLINA ELECTRIC AN

RCT-101 (08-16) **PAGE 3 OF 4 PA CORPORATE NET INCOME TAX REPORT 2016**

SECTION C: CORPORATE STATUS CHANGES

Final Report N

PA Corporations:

Did you ever transact business anywhere? N If yes, enter date all business activity ceased

Did you hold assets anywhere? N If yes, enter date of final disposition of assets*

Foreign Corporations:

Did you ever transact business in PA on your own or through an unincorporated entity? N If yes, enter date PA business activity ceased

Did you hold assets in PA on your own or through an unincorporated entity? N If yes, enter date of final disposition of PA assets*

*Schedule of Disposition of Assets, REV-861, must be completed and filed with this report.

Has the corporation sold or transferred in bulk, 51 percent or more of any class of assets? (See instructions.) N

If yes, enter the following information. (Include a separate schedule if additional space is needed.)

Purchaser Name
Address Line 1
Address Line 2
City Province
State Country Code
ZIP Foreign Postal Code

SECTION D: GENERAL INFORMATION QUESTIONNAIRE

Describe corporate activity in PA NATURAL GAS STORAGE
Describe corporate activity outside PA ELECTRIC AND NATURAL GAS UTILITY
Other states in which taxpayer has activity SC, GA, LA, WV, MS

State of Incorporation SC Incorporation Date 07191924

1. Does any corporation, individual or other business entity hold all or a majority of the stock of this corporation? 1 Y
2. Does this corporation own all or a majority of stock in other corporations? 2 N
3. Is this taxpayer a partnership or other unincorporated entity that elects to file federal taxes as a corporation? 3 N
4. Has the federal government changed taxable income as originally reported for any prior period for which reports of change have not been filed in PA? 4 N

If yes: First Period End Date: Last Period End Date:

Accounting Method - Federal Tax Return

A A = Accrual C = Cash O = Other

Other

Accounting Method - Financial Statements

A A = Accrual C = Cash O = Other

Other

6Y4665 3.000

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1010016380

1010016480

REVENUE ID 1000236565
TAX YEAR END 12312016 NAME SOUTH CAROLINA ELECTRIC AN

RCT-101 (08-16) **PAGE 4 OF 4 PA CORPORATE NET INCOME TAX REPORT 2016**

SCHEDULE OF REAL PROPERTY IN PA (Include a separate schedule if additional space is needed.)

Did you own or rent property in PA titled to the corporation or any Single Member LLC during this filing period? N

If yes, the below section must be completed.

O = Own R = Rent	Street Address	City	County	KOZ/KOEZ

CORPORATE OFFICERS

(See instructions.)
Must provide requested information for all filled officer positions.

	SSN	Last Name	First Name	MI
President/Managing Partner		MARSH	KEVIN	B
Vice President		ADDISON	JIMMY	E
Secretary		CHAMPION	GINA	S
Treasurer/Tax Manager		CANNON	MARK	R

PREPARER'S INFORMATION

Mail to Preparer N
Firm Federal EIN
Firm Name
Address Line 1
Address Line 2
City
State
ZIP
Province
Country Code
Foreign Postal Code

I affirm under penalties prescribed by law, this report, including any accompanying schedules and statements, has been prepared by me and to the best of my knowledge and belief is a true, correct and complete report.

Tax Preparer's Signature	Date

INDIVIDUAL PREPARER
PHONE
EMAIL
PTIN/SSN

6Y4626 2.000

RCT-101,Page 1, Step D,Tax Summary,Payments and Credits Detail

	Corporation Net Income
Tentative payments	676.
Payments with extension	
Keystone Opp Zone	
Credits:	
Neighborhood Assist.	
Employment Incentive	
Educational Imp.	
Coal Waste Removal	
Jobs Creation Tax	
Pennsylvania R & D	
Totals	676.

Statement 1

FORMS (TAX)

FORM NUMBER

STATE 1120

JURISDICTION

WEST VIRGINIA

MONTH

YEAR

2016

TYPE

INCOME

COMPANY

CONSOLIDATED

(1062)
CNF-120
REV 8-16

West Virginia Corporation Net Income Tax Return

2016

FEIN 570784499

EXTENDED DUE DATE 10 16 2017

☐ 52/53 WEEK FILER
Day of week ended

TAX YEAR

BEGINNING	MM	DD	YYYY	ENDING	MM	DD	YYYY
	01	01	2016		12	31	2016

Business Name SCANA CORPORATION

☐ CHECK HERE FOR CHANGE OF ADDRESS

220 OPERATION WAY
First Line of Address

Second Line of Address

CAYCE
City

SC
State

29033 - 3701
Zip code

CLARKSBURG
Principal Place of Business in West Virginia

NATURAL GAS STORAGE
Type of Activity in West Virginia

CHECK APPLICABLE BOXES

TYPE OF ENTITY:
[X] CORPORATION
☐ NONPROFIT

TYPE OF RETURN:
☐ INITIAL ☐ RAR
☐ FINAL ☐ AMENDED

FILING METHOD
☐ SEPARATE ENTITY BASED*
[X] COMBINED (Must complete Schedule UB-4CR)
☐ Separate Combined ☐ Group combined (designate surety FEIN)
☐ Worldwide Election
☐ OTHER (explain)

* If separate, were you part of a federal consolidated return?
☐ YES * ☐ NO
If YES, enter parent's FEIN and name

SIGNED FEDERAL FORM ATTACHED (FIRST 5 PAGES)
[X] 1120 ☐ PROFORMA 1120 ☐ 990 ☐ 990T

Are disregarded entities included in this return?
☐ YES ☐ NO If YES, complete the Tax Return Questionnaire on page 25.

STATE OF COMMERCIAL DOMICILE: SC

PERSON AND PHONE NUMBER TO CONTACT CONCERNING THIS RETURN
NAME: JAMES E SWAN IV
NUMBER: 803 217-9000

SEPARATE ENTITY FILERS COMPLETE CNF-120APT BEFORE COMPLETING THIS RETURN (See instructions pages 9-11)
COMBINED FILERS COMPLETE UB-4APT BEFORE COMPLETING THIS RETURN (See instructions pages 15-17)

(IF FILING A COMBINED RETURN SKIP LINES 1 THROUGH 13 AND COMPLETE UB SCHEDULES)

1. Federal taxable income (per attached federal return)			1	.00
2. Total increasing adjustments (Schedule B line 13)	2	.00		
3. Total decreasing adjustments (Schedule B line 26)	3	.00		
4. Adjusted federal taxable income (Line 1 plus line 2 minus line 3)			4	.00

Wholly West Virginia corporations check here ☐ and go to line 10

5. Total nonbusiness income allocated everywhere (Form CNF-120APT, Schedule A-1, line 8, Column 3	5	.00
6. Total income subject to apportionment (subtract line 5 from line 4)	6	.00
7. WV Apportionment Factor (Form CNF-120APT, Sch. B Part 1, line 8, or either Part 2 or Part 3 Column 3) COMPLETED FORM **MUST** BE ATTACHED	7	
8. West Virginia apportioned income (line 6 multiplied by line 7)	8	.00

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(1062)

NAME SCANA CORPORATION

FEIN 570784499

8. West Virginia apportioned income (from page 1 line 8)	8		.00
9. Nonbusiness income allocated to West Virginia (Form CNF-120APT Sch. A2, Line 12)	9		.00
10. West Virginia adjusted taxable income – Multistate corporations add lines 8 and 9; wholly West Virginia corporations enter amount from line 4	10		.00
11. Net operating loss carryforward (Schedule NOL, column 6 total)	11		.00
12. Subtotal (line 10 less line 11)	12		.00
13. REIT Inclusion and other Taxable income	13		.00
14. WV Net Taxable Income (Add lines 12 and 13) (**Combined filers should enter amount from line 20 of Schedule UB 3**)	14		-839 .00
15. Corporate Net Income Tax Rate	15		0.065
16. Corporate Net Income Tax (line 14 multiplied by line 15)	16		.00
17. Corporate Net Income Tax Credits (Column 2, line 17, Form CNF-120TC)	17		.00
18. Adjusted Corporate Net Income Tax (subtract line 17 from line 16)	18		.00
19. Prior year carryforward credit	19	5490 .00	
20. Estimated and extension payments	20	.00	
21. Withholding must match the Grand Total on the CNF-120W, WV Withholding - Credit Schedule unless withholding is from NRSR ☐ CHECK HERE IF WITHHOLDING IS FROM NRSR (NONRESIDENT SALE OF REAL ESTATE)	21	.00	
22. Amount paid with original return (Amended Return Only)	22	.00	
23. Payments (add lines 19 through 22; must match total on Schedule C)	23		5490 .00
24. Overpayment previously refunded or credited (Amended return only)	24		.00
25. TOTAL PAYMENTS (subtract line 24 from line 23)	25		5490 .00
26. If line 25 is *larger* than line 18 enter **overpayment**	26		5490 .00
27. Amount of line 26 to be credited to next year's tax	27		5490 .00
28. Amount of line 26 to be refunded (Subtract line 27 from line 26)	28		.00
29. If line 25 is *smaller* than line 18, enter **tax due** here	29		.00
30. Interest for late payment (see instructions)	30		.00
31. Additions to tax for late filing and/or late payment (see instructions)	31		.00
32. Penalty for underpayment of estimated tax (line 6, Form CNF-120U; Attach schedule)	32		.00
33. TOTAL DUE with this return (add lines 29 through 32)	33		.00

Direct Deposit of Refund ☐ CHECKING ☐ SAVINGS

ROUTING NUMBER ACCOUNT NUMBER

PLEASE REVIEW YOUR ACCOUNT INFORMATION FOR ACCURACY. PROVIDING INCORRECT ACCOUNT INFORMATION MAY RESULT IN A $15.00 RETURNED PAYMENT CHARGE.

PLEASE SEE PAGE 3 OF INSTRUCTIONS FOR PAYMENT OPTIONS.

Under penalties of perjury, I declare that I have examined this return, accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct and complete. I authorize the State Tax Department to discuss my return with my preparer. ☐ YES ☒ NO

Signature of Officer/Partner or Member	Print name of Officer/Partner or member	Title	Date	Business Telephone Number
[signature]	JAMES E SWAN IV	CONTROLLER	10/11/17	8032179000

Paid preparer's signature	Firm's name and address	Date	Preparer's Telephone Number
	INTERNALLY PREPARED 220 OPERATION WAY CAYCE, SC 29033-3701		

MAIL TO:
WEST VIRGINIA STATE TAX DEPARTMENT
TAX ACCOUNT ADMINISTRATION DIVISION
PO BOX 1202
CHARLESTON WV 25324-1202

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(1062)

SCHEDULE UB-2 (FORM CNF-120)

Calculation of WV Business Capital for Combined Group
(§11-23-3(b)(2))

2016

NAME SCANA CORPORATION | FEIN 570784499

	GROUP 1 Regular Entities	GROUP 2 Motor Carriers	GROUP 3 Financial organizations
DOLLAR AMOUNT OF COMMON AND PREFERRED STOCK			
1. Beginning Balance	2417595500 .00	.00	.00
2. Ending Balance	2417595500 .00	.00	.00
3. Average [(line 1 + line 2) ÷ 2]	2417595500 .00	.00	.00
PAID IN CAPITAL SURPLUS			
4. Beginning Balance	-14282362 .00	.00	.00
5. Ending Balance	-14282362 .00	.00	.00
6. Average [(line 4 + line 5) ÷ 2]	-14282362 .00	.00	.00
RETAINED EARNINGS - APPROPRIATED AND UNAPPROPRIATED			
7. Beginning Balance	3118303738 .00	.00	.00
8. Ending Balance	3383244353 .00	.00	.00
9. Average [(line 7 + line 8) ÷ 2]	3250774046 .00	.00	.00
ADJUSTMENTS TO SHAREHOLDERS EQUITY			
10. Beginning Balance	-65427485 .00	.00	.00
11. Ending Balance	-49050610 .00	.00	.00
12. Average [(line 10 + line 11) ÷ 2]	-57239048 .00	.00	.00
13. Add lines 3, 6, 9, and 12	5596848136 .00	.00	.00
14. Less cost of treasury stock (average)	12134021 .00	.00	.00
15. Capital (Subtract line 14 from line 13)	5584714115 .00	.00	.00
16. LINE LEFT BLANK INTENTIONALLY.			
17. Obligations/investments allowance (from UB-4CR)	.00	.00	.00
18. Adjusted capital (subtract line 17 from line 15)	5584714115 .00	.00	.00
19. Group adjusted capital	5584714115 .00	.00	.00
20. Apportionment factor (round to six (6) decimal places)	0.000015		
21. Business capital (line 19 multiplied by line 20)	83771 .00	.00	.00
22. Combined total business capital (add line 21 from groups 1 through 3)			83771 .00

Only use the UB forms & schedules when filing combined reporting.

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6Y5838 1.000

(1062)
SCHEDULE
UB-3
(FORM CNF-120)

Calculation of WV Taxable Income for Combined Group (§11-24-6)

2016

NAME SCANA CORPORATION

FEIN 570784499

	GROUP 1 Regular Entities	GROUP 2 Motor Carriers	GROUP 3 Financial organizations
PART 1 - INCREASING ADJUSTMENTS			
1. Federal taxable income	-57577879.00	.00	.00
2a. Interest/dividends from state/local bonds/ securities	.00	.00	.00
2b. US obligation interest/dividends not exempt from state tax	.00	.00	.00
2c. Income/other tax based upon net income, deducted on your federal return	1663086.00	.00	.00
2d. Federal depreciation/amortization for wholly WV corporation water/air pollution control facilities	.00	.00	.00
2e. Unrelated business taxable income of a corporation exempt from federal tax (IRC Sec. 512)	.00	.00	.00
2f. Federal Net Operating Loss deduction	.00	.00	.00
2g. WV Neighborhood Investment Programs Tax Credit (charitable contributions to NIPA)	.00	.00	.00
2h. Net operating loss from sources outside US	.00	.00	.00
2i. Foreign Taxes deducted on your federal return	.00	.00	.00
2j. IRC Sec. 199 deduction (WV §11-24-6a)	.00	.00	.00
2k. Add back for expenses related to certain REIT's and regulated investment companies and certain interest and intangible expenses (WV Code §11-24-4b)	.00	.00	.00
2l. Other increasing adjustments	.00	.00	.00
3. **Total increasing adjustments (Add lines 2a - 2l)**	1663086.00	.00	.00
PART 2 - DECREASING ADJUSTMENTS			
4a. Refund/credit on taxes based upon net income included in federal taxable income	.00	.00	.00
4b. Interest expenses on obligations/securities not allowed in determining federal taxable income	.00	.00	.00
4c. Salary expense not allowed on federal return due to claiming federal jobs credit	.00	.00	.00
4d. Foreign dividend gross-up (IRC Sec. 78)	.00	.00	.00
4e. Subpart F income (IRC Sec. 951)	.00	.00	.00
4f. Taxable income from sources outside US	.00	.00	.00

(continued on next page)

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(1062)

FEIN 570784499

(Continued from previous page)	GROUP 1 Regular Entities	GROUP 2 Motor Carriers	GROUP 3 Financial Organizations
PART 2 - DECREASING ADJUSTMENTS (CONTINUED)			
4g. Cost of wholly WV water/air pollution control facilities	.00	.00	.00
4h. Federal taxable income employer contributions to medical savings accounts withdrawn for non-medical purposes	.00	.00	.00
4i Allowance for obligations/investments	.00	.00	.00
4j. Other decreasing adjustments	.00	.00	.00
5. Total decreasing adjustments (add lines 4a - 4j)	.00	.00	.00
6. Adj. taxable income (add lines 1 & 3, subtract line 5)	-55914793 .00	.00	.00
7. Total nonbusiness income allocated everywhere	.00	.00	.00
8. Total non-unitary business income	.00	.00	.00
9. Income subject to apportionment - subtract lines 7 and 8 from line 6	-55914793 .00	.00	.00
10. Group income subject to apportionment for each member	-55914793 .00	.00	.00
11. WV apportionment factor (round to six [6] decimal places)	0.000015		
12. WV apportionment income - line 10 multiplied by line 11	-839 .00	.00	.00
13. Nonbusiness income allocated to WV	.00	.00	.00
14. Non-unitary business income apportioned to WV	NONE .00	.00	.00
15. WV adjusted taxable income (add lines 12, 13, and 14)	-839 .00	.00	.00
16. WV net operating loss being used this period (from CNF-120 Schedule NOL, total of Column 6)	.00	.00	.00
17. Subtotal (subtract line 16 from line 15)	-839 .00	.00	.00
18. REIT Inclusion and other WV taxable income	.00	.00	.00
19. WV net taxable income - add lines 17 and 18	-839 .00	.00	.00
20. Combined total WV net taxable income (add lines 19 from groups 1 through 3) enter on Form CNF-120, Line 14			-839 .00
21. WV Net Operating Loss Remaining Unused (from CNF-120 Schedule NOL, total of Column 7)		.00	

T A 3 0 2 0 1 6 1 6

(1062) SCHEDULE **UB-4APT** (FORM CNF-120)

Allowance for Governmental Obligations/Obligations Secured by Residential Property (§11-24-6(f))

(Only use the UB forms & schedules when filing a combined report) **2016**

MEMBER NAME SCANA CORPORATION

UNITARY FEIN 57-0784499

This form is used by corporations that are subject to tax in more than one state to allocate and apportion their income and/or capital to the State of West Virginia. Complete for each corporation and retain for your records.

MEMBER FEIN 570784499

Schedule C

Allowance for Governmental Obligations/Obligations Secured by Residential Property (§11-24-6(f))

		AVERAGE MONTHLY BALANCE
1. Federal obligations and securities	1	.00
2. Obligations of West Virginia and any political subdivision of West Virginia	2	.00
3. Investments or loans primarily secured by mortgages or deeds of trusts on residential property located in West Virginia	3	.00
4. Loans primarily secured by a lien or security agreement on a mobile home or double-wide located in West Virginia	4	.00
5. TOTAL (Add lines 1 through 4)	5	.00
6. Total assets as shown on Schedule L, Federal Form 1120 or 1120A	6	.00
7. Divide line 5 by line 6 (round to six (6) decimal places)	7	
8. Adjusted income (UB-4CR line 1 plus line 3 minus line 5, plus UB-4APT Schedule A2, line 9, 10, & 11)	8	-65988354 .00
9. ALLOWANCE (line 7 multiplied by line 8, disregard sign) Enter here and on UB-4CR, line 4i	9	.00

6Y5817 1.000

(1062)
SCHEDULE
UB-4APT
(FORM CNF-120)

Allocation and Apportionment for Multistate Businesses
(Only use the UB forms & schedules when filing a combined report)

2016

MEMBER NAME SCANA CORPORATION

UNITARY FEIN 57-0784499

MEMBER FEIN 570784499

This form is used by corporations that are subject to tax in more than one state to allocate and apportion their income and/or capital to the State of West Virginia. **Complete for each corporation and retain for your records.**

SCHEDULE A1 EVERYWHERE - Allocation of Nonbusiness Income For Multistate Businesses (§11-24-7)

Types of Allocable Income	Column 1 - Gross Income	Column 2 - Related Expenses	Column 3 - Net Income
1. Rents	.00	.00	.00
2. Royalties	.00	.00	.00
3. Capital gains/losses	.00	.00	.00
4. Interest	.00	.00	.00
5. Dividends	.00	.00	.00
6. Patent/copyright royalties	.00	.00	.00
7. Gain - Sale of natural resources (IRC Sec. 631 (a)(b))	.00	.00	.00
8. Nonbusiness income/loss - Sum of lines 1 through 7, column 3. Enter this amount on line 7 of the Corporate Net Income Tax Tab of the UB-4CR for each corporation			.00

SCHEDULE A2 WEST VIRGINIA - Allocation of Nonbusiness Income for Multistate Businesses (§11-24-7)

Types of Allocable Income	Column 1 - Gross Income	Column 2 - Related Expenses	Column 3 - Net Income
1. Rents	.00	.00	.00
2. Royalties	.00	.00	.00
3. Capital gains/losses	.00	.00	.00
4. Interest	.00	.00	.00
5. Dividends	.00	.00	.00
6. Patent/copyright royalties	.00	.00	.00
7. Gain - Sale of natural resources (IRC Sec. 631 (a)(b))	.00	.00	.00
8. Nonbusiness income/loss (Sum of lines 1 through 7, column 3)			.00
9. Less cost of West Virginia water/air pollution control facilities this year			.00
10. Federal depreciation/amortization on those facilities this year			.00
11. Federal depreciation/amortization on such facilities expensed in a prior year			.00
12. Net nonbusiness income/loss allocated to West Virginia - Sum of lines 8 through 11, column 3. Enter this amount on line 13 of the Corporate Net Income Tax Tab of the UB-4CR for each corporation			.00

(1062)
SCHEDULE
UB-4APTSUM
(FORM CNF-120)

Allocation and Apportionment Summary for Unitary Group
(Only use the UB forms & schedules when filing a combined report)

2016

NAME	SCANA CORPORATION	FEIN	57-0784499

This form is used by corporations that are subject to tax in more than one state to allocate and apportion their income and/or capital to the State of West Virginia Complete this summary for the Unitary Group and submit as part of your return

SCHEDULE B1 APPORTIONMENT FACTORS FOR MULTI STATE BUSINESSES (§11-24-7 AND §11-23-5)

LINES 1 & 2 Divide column 1 by column 2 and enter six (6) digit decimal in column 3
LINE 5 Column 1 - Enter line 3 Column 2 - line 3 less line 4 Divide column 1 by column 2 and enter six (6) digit decimal in column 3

PART 1 REGULAR FACTOR	Column 1 West Virginia	Column 2 Combined Group Everywhere	Column 3 Decimal Fraction
1 Total property	565453 .00	9997880140 .00	0.000057
2 Total payroll	.00	467543733 .00	NONE
3 Total sales	.00	5269643227 .00	
4 Sales to purchasers in a state where you are not taxable		.00	
5 Adjusted sales	.00	5269643227 .00	NONE
6 Adjusted sales (enter line 5 again)	.00	5269643227 .00	NONE
7 TOTAL Add lines 1, 2, 5, and 6 of column 3			0.000057
8 APPORTIONMENT FACTOR - Line 7 divided by the number 4, reduced by the number of factors showing zero in column 2, lines 1, 2, 5, and 6 Enter six (6) digits after the decimal Must match apportionment factor shown on UB-2, columns 1 & 2, line 20 and UB-3, column 1, line 11			0.000015

PART 2 - MOTOR CARRIER FACTOR (§11-24-7a)
VEHICLE MILEAGE - Use part 1 to figure the apportionment factor for Business Capital Calculation Must match apportionment factor shown on UB-3, column 2, line 11

Column 1 West Virginia	Column 2 Combined Group Everywhere	Column 3 Decimal Fraction (divide column 1 by column 2 and round to six [6] decimal places)

PART 3 - FINANCIAL ORGANIZATION FACTOR (§11-24-7b and §11-23-5a)
GROSS RECEIPTS - Must match apportionment factors on UB-2, column 3, line 20 and UB-3, column 3, line 11

Column 1 West Virginia	Column 2 Combined Group Everywhere	Column 3 Decimal Fraction (divide column 1 by column 2 and round to six [6] decimal places)
.00	.00	

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Name of Business	SC FUEL COMPANY	SCANA CORP SECURI	PSNC CARDINAL	PSNC BLUE RIDGE	CLEAN ENERGY ENT	PUBLIC SERVICE	SERVICECARE INC	SCANA ENERGY MARK	SCANA COMMUNIC	SC GENERATING
FEIN	57-0691209	20-0989017	56-1955423	56-1791784	56-1078443	56-2128483	57-1007394	57-0850977	51-0394908	57-0784496
Entity Type	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity
Increasing Adjustments										
1. Federal Taxable Income	9,719,946.00	0.00	3,010,263.00	1,567,625.00	-1,703.00	-47,294,144.00	-1,192,160.00	46,187,165.00	1,172,240.00	9,555,828.00
2a. Interest dividends from state/local bond/securities										
2b. US obligation interest/dividends not exempt from state tax										
2c. Income/other tax based upon net income deducted on your federal return			57,598.00	40,471.00		298,416.00		1,256,602.00		0.00
2d. Federal depreciation/amortization for wholly WV corporation water/air polution control facilities										
2e. Unrelated business taxable income of a corporation exempt from federal tax (IRC Sec. 512)										
2f. Federal Net Operating Loss Deduction										
2g. WV Neighborhood Investment Programs Tax Credit (charitable contributions to NIPA)										
2h. Net operating loss from sources outside US										
2i. Foreign Taxes deducted on your federal return										
2j. IRC Sec. 199 deduction (WV §11-24-6e)										
2k. Add back for expenses related to certain REIT's and Regulated Investment Companies and certain interest and intangible expenses (WV Code §11-24-4b)										
2l. Other increasing adjustments										
3. Total increasing adjustments	0.00	0.00	57,598.00	40,471.00	0.00	298,416.00	0.00	1,256,602.00	0.00	0.00
Decreasing Adjustments										
4a. Refund/credit on taxes based upon net income included in federal taxable income										
4b. Interest expense on obligations/securities not allowed in determining federal taxable income										
4c. Salary expense not allowed on federal return due to claiming federal jobs credit										
4d. Foreign dividend gross-up (IRC Sec. 78)										
4e. Subpart F income (IRC Sec. 951)										
4f. Taxable income from sources outside US										
4g. Cost of wholly WV water/air pollution control facilities										
4h. Fed taxable income employer contributions to medical savings accounts withdrawn for non-medical purposes										
4i. Allowance for obligations/investments										
4j. Other decreasing adjustments										
5. Total decreasing adjustments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6. Adj. taxable income-add lines 1 & 3, subtract line 5	9,719,946.00	0.00	3,067,861.00	1,608,096.00	-1,703.00	-46,995,728.00	-1,192,160.00	[illegible]	[illegible]	[illegible]
7. Total nonbusiness income allocated everywhere.										
8. Total non-unitary business income										
9. Income subject to apportionment	9,719,946.00	0.00	3,067,861.00	1,608,096.00	-1,703.00	-46,995,728.00	-1,192,160.00	[illegible]	[illegible]	[illegible]
10. Group income subject to apportionment for each member	55,914,793.00	55,914,793.00	55,914,793.00	55,914,793.00	55,914,793.00	55,914,793.00	55,914,793.00	55,914,793.00	[illegible]	[illegible]
11. WV apportionment factor						0.000014				
12. WV apportioned income	0.00	0.00	0.00	0.00	0.00	[illegible]	0.00	0.00	[illegible]	[illegible]
13. Nonbusiness income allocated to WV										
14. Non-unitary business income apportioned to West Virginia										
15. WV taxable income	0.00	0.00	0.00	0.00	0.00	-784.00	0.00	0.00	[illegible]	[illegible]
16. WV net operating loss carryforward										
17. Subtotal (subtract 16 from 15)	0.00	0.00	0.00	0.00	0.00	-784.00	0.00	0.00	[illegible]	[illegible]
18. REIT inclusion / other WV taxable income										
19. WV net taxable income	0.00	0.00	0.00	0.00	0.00	-784.00	0.00	0.00	[illegible]	[illegible]

Name of Business	SC ELECTRIC & GAS	SCANA SERVICES	SCANA CORP	Eliminations (Attach Explanations)	Combined
FEIN	57-0248695	57-1092169	57-0784499		
Entity Type	Regular Entity	Regular Entity	Regular Entity		
Increasing Adjustments					
1. Federal Taxable Income	-27,000,082.00	10,685,705.00	-65,988,354.00	0.00	-57,577,879.00
2a. Interest dividends from state/ local bond/securities					0.00
2b. US obligation interest/dividends not exempt from state tax					0.00
2c. Income/other tax based upon net income deducted on your federal return	0.00	10,000.00			[illegible]
2d. Federal depreciation/amortization for wholly WV corporation water/air pollution control facilities					0.00
2e. Unrelated business taxable income of a corporation exempt from federal tax (IRC Sec. 512)					0.00
2f. Federal Net Operating Loss Deduction					0.00
2g. WV Neighborhood Investment Programs Tax Credit (charitable contributions to NIPA)					0.00
2h. Net operating loss from sources outside US					0.00
2i. Foreign Taxes deducted on your federal return					0.00
2j. IRC Sec. 199 deduction (WV §11-24-6a)					0.00
2k. Add back for expenses related to certain REIT's and Regulated Investment Companies and certain interest and intangible expenses (WV Code §11-24-4b)					0.00
2l. Other increasing adjustments					0.00
3. Total increasing adjustments	0.00	10,000.00	0.00	0.00	[illegible]
Decreasing Adjustments					
4a. Refund/credit on taxes based upon net income included in federal taxable income					0.00
4b. Interest expense on obligations/securities not allowed in determining federal taxable income					0.00
4c. Salary expense not allowed on federal return due to claiming federal jobs credit					0.00
4d. Foreign dividend gross-up (IRC Sec. 78)					0.00
4e. Subpart F income (IRC Sec. 951)					0.00
4f. Taxable income from sources outside US					0.00
4g. Cost of wholly WV water/air pollution control facilities					0.00
4h. Fed taxable income employer contributions to medical savings accounts withdrawn for non-medical purposes					0.00
4i. Allowance for obligations/investments					0.00
4j. Other decreasing adjustments					0.00
5. Total decreasing adjustments	0.00	0.00	0.00	0.00	0.00
6. Adj. taxable income-add lines 1 & 3, subtract line 5	-27,000,082.00	10,685,705.00	-65,988,354.00	0.00	-55,914,793.00
7. Total nonbusiness income allocated everywhere.					0.00
8. Total non-unitary business income					0.00
9. Income subject to apportionment	-27,000,082.00	10,685,705.00	-65,988,354.00	0.00	-55,914,793.00
10. Group income subject to apportionment for each member	-55,914,793.00	-55,914,793.00	-55,914,793.00		-55,914,793.00
11. WV apportionment factor	0.000001		0.000000		0.000015
12. WV apportioned income	[illegible]	0.00	0.00		[illegible]
13. Nonbusiness income allocated to WV					0.00
14. Non-unitary business income apportioned to West Virginia					0.00
15. WV taxable income	[illegible]	0.00	0.00		[illegible]
16. WV net operating loss carryforward					0.00
17. Subtotal (subtract 16 from 15)	[illegible]	0.00	0.00		[illegible]
18. REIT inclusion / other WV taxable income					0.00
19. WV net taxable income	[illegible]	0.00	0.00		[illegible]

Name of Business	SCANA CORP SECURITY	PSNC CARDINAL PIPELIN	PSNC BLUE RIDGE	CLEAN ENERGY E	PUBLIC SERVICE
FEIN	20-0989017	56-1955423	56-1791764	56-1078443	56-2128483
Entity Type	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity
Dollar Amount of Common and Preferred Stock					
1. Beginning Balance	1000.00	1000.00	1000.00	2000.00	3000.00
2. Ending Balance	1000.00	1000.00	1000.00	2000.00	3000.00
3. Average	1000.00	1000.00	1000.00	2000.00	3000.00
Paid in Capital Surplus					
4. Beginning Balance		846788.00	473954.00	438.00	633359516.00
5. Ending Balance		846788.00	473954.00	438.00	633359516.00
6. Average	0.00	846788.00	473954.00	438.00	633359516.00
Reatained Earnings - Appropriated and Unapropriated					
7. Beginning Balance		10536683.00	2053827.00	15296.00	106559263.00
8. Ending Balance		9424282.00	1531712.00	6890.00	132184843.00
9. Average	0.00	9980483.00	1792770.00	[illegible]	[illegible]
Adjustments to Shareholders Equity					
10. Beginning Balance		-7135.00	-4547.00		1321675.00
11. Ending Balance		-544.00	3519.00		1491853.00
12. Average	0.00	-3840.00	-514.00	0.00	[illegible]
13. Sum of lines 3, 6, 9, & 12	1000.00	10824431.00	2267210.00	[illegible]	751321805.00
14. Cost of Treasury Stock					
15. Capital	1000.00	10824431.00	2267210.00	[illegible]	751321805.00
16. Multipler for obligations/ investments allowance (line 7 schedule B-1, CNF-120					
17. Obligations/investment allowance	0.00	0.00	0.00	0.00	0.00
18. Adjusted Capital	1000.00	10824431.00	2267210.00	[illegible]	751321805.00
19. Group adjusted capital	5584714115.00	5584714115.00	5584714115.00	5584714115.00	5584714115.00
20. Apportionment Factor (Sched. B, UB-4 APT)					0.000014
21. Taxable capital	0.00	0.00	0.00	0.00	[illegible]

Name of Business	SERVICECARE INC	SCANA ENERGY MARKET	SCANA COMMUNICATIONS	SC GENERATING	SC FUEL COMPANY
FEIN	57-1007394	57-0850977	51-0394908	57-0784498	57-0691209
Entity Type	Regular Entity	Regular Entity	Regular Entity	Regular Entity	Regular Entity
Dollar Amount of Common and Preferred Stock					
1. Beginning Balance	1000.00	1000.00	20000.00	20000000.00	1000.00
2. Ending Balance		1000.00	20000.00	20000000.00	1000.00
3. Average	500.00	1000.00	20000.00	20000000.00	[illegible]
Paid in Capital Surplus					
4. Beginning Balance	10025666.00	45455110.00	903316.00	32307572.00	2695226.00
5. Ending Balance		45455110.00	903316.00	32307572.00	2695226.00
6. Average	5012833.00	45455110.00	903316.00	32307572.00	[illegible]
Reatained Earnings - Appropriated and Unapropriated					
7. Beginning Balance	-8580838.00	46380846.00	1398940.00	73707400.00	
8. Ending Balance		41094100.00	960896.00	79222288.00	
9. Average	-4290419.00	43737473.00	1179918.00	76464844.00	[illegible]
Adjustments to Shareholders Equity					
10. Beginning Balance	-201326.00	-10720754.00		-6622.00	
11. Ending Balance		-784536.00		-6810.00	
12. Average	-100663.00	-5752645.00	0.00	-6716.00	[illegible]
13. Sum of lines 3, 6, 9, & 12	622251.00	83440938.00	2103234.00	128766700.00	[illegible]
14. Cost of Treasury Stock					
15. Capital	622251.00	83440938.00	2103234.00	128766700.00	[illegible]
16. Multipler for obligations/ investments allowance (line 7 schedule B-1, CNF-120					
17. Obligations/investment allowance	0.00	0.00	0.00	0.00	0.00
18. Adjusted Capital	622251.00	83440938.00	2103234.00	128765700.00	2698226.00
19. Group adjusted capital	5584714115.00	5584714115.00	5584714115.00	5584714115.00	[illegible]
20. Apportionment Factor (Sched. B, UB-4 APT)					
21. Taxable capital	0.00	0.00	0.00	0.00	0.00

Name of Business	SC ELECTRIC & GAS	SCANA SERVICES	SCANA CORP	Eliminations	Combined
FEIN	57-0248695	57-1092169	57-0784499	(Attach Explanations)	
Entity Type	Regular Entity	Regular Entity	Regular Entity		
Dollar Amount of Common and Preferred Stock					
1. Beginning Balance	576505122.00	1000.00	2417575500.00	596511122.00	2417598500.00
2. Ending Balance	576505122.00	1000.00	2417575500.00	596510122.00	2417598500.00
3. Average	576505122.00	1000.00	2417575500.00		2417595500.00
Paid In Capital Surplus					
4. Beginning Balance	2183832337.00	6849916.00	-9030772.00	2922001429.00	[illegible]4281362.00
5. Ending Balance	2283832337.00	6849916.00	-14923664.00	3006082871.00	[illegible]
6. Average	2233832337.00	6849916.00	-11977218.00		[illegible]
Retained Earnings - Appropriated and Unapropriated					
7. Beginning Balance	2265470450.00		3111012466.00	2490250595.00	[illegible]
8. Ending Balance	2481211937.00		3382283456.00	2744662271.00	[illegible]
9. Average	2373341194.00	0.00	3246647961.00		3260774046.00
Adjustments to Shareholders Equity					
10. Beginning Balance	-2770003.00		-65633223.00	-15237800.00	[illegible]
11. Ending Balance	-2973265.00		-48772317.00	-4975196.00	[illegible]
12. Average	-2871634.00	0.00	-57202770.00		[illegible]
13. Sum of lines 3, 6, 9, & 12	5180807019.00	6850916.00	5595043473.00		5596848138.00
14. Cost of Treasury Stock			12134021.00		12134021.00
15. Capital	5180807019.00	6850916.00	5582909452.00		5584714115.00
16. Multipler for obligations/ investments allowance (line 7 schedule B-1, CNF-120			0.000000		
17. Obligations/investment allowance	0.00	0.00	0.00		0.00
18. Adjusted Capital	5180807019.00	6850916.00	5582909452.00		[illegible]
					Combined Capital Total
19. Group adjusted capital	5584714115.00	5584714115.00	5584714115.00		[illegible]
20. Apportionment Factor (Sched. B, UB-4 APT)	0.000001		0.000000		0.000015
21. Taxable capital	5585.00	0.00	0.00		[illegible]

Form **7004** (Rev. December 2016) Department of the Treasury Internal Revenue Service

Application for Automatic Extension of Time To File Certain Business Income Tax, Information, and Other Returns

▶ File a separate application for each return.
▶ Information about Form 7004 and its separate instructions is at www.irs.gov/form7004.

OMB No. 1545-0233

Print or Type

Name	Identifying number
SCANA CORPORATION	57-0784499
Number, street, and room or suite no. (If P.O. box, see instructions.)	
220 OPERATION WAY	
City, town, state, and ZIP code (If a foreign address, enter city, province or state, and country (follow the country's practice for entering postal code)).	
CAYCE, SC 29033-3701	

Note: File request for extension by the due date of the return for which the extension is granted. See instructions before completing this form.

Part I **Automatic Extension for C Corporations With Tax Years Ending December 31.** See instructions.

1a Enter the form code for the return listed below that this application is for 1 2

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part II **Automatic Extension for Certain Estates and Trusts.** See instructions.

b Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1041 (estate other than a bankruptcy estate)	04	Form 1041 (trust)	05

Part III **Automatic Extension for Entities Not Using Part I, II, or IV.** See instructions.

c Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 706-GS(D)	01	Form 1120-ND (section 4951 taxes)	20
Form 706-GS(T)	02	Form 1120-PC	21
Form 1041 (bankruptcy estate only)	03	Form 1120-POL	22
Form 1041-N	06	Form 1120-REIT	23
Form 1041-QFT	07	Form 1120-RIC	24
Form 1042	08	Form 1120S	25
Form 1065	09	Form 1120-SF	26
Form 1065-B	10	Form 3520-A	27
Form 1066	11	Form 8612	28
Form 1120	12	Form 8613	29
Form 1120-C	34	Form 8725	30
Form 1120-F	15	Form 8804	31
Form 1120-FSC	16	Form 8831	32
Form 1120-H	17	Form 8876	33
Form 1120-L	18	Form 8924	35
Form 1120-ND	19	Form 8928	36

Part IV **Automatic Extension for C Corporations With Tax Years Ending June 30.** See instructions.

d Enter the form code for the return listed below that this application is for . . . . .

Application Is For:	Form Code	Application Is For:	Form Code
Form 1120	12	Form 1120-ND (section 4951 taxes)	20
Form 1120-C	34	Form 1120-PC	21
Form 1120-F	15	Form 1120-POL	22
Form 1120-FSC	16	Form 1120-REIT	23
Form 1120-H	17	Form 1120-RIC	24
Form 1120-L	18	Form 1120-SF	26
Form 1120-ND	19		

Part V All Filers Must Complete This Part

2 If the organization is a foreign corporation that does not have an office or place of business in the United States, check here . . . ▶ [ ]

3 If the organization is a corporation and is the common parent of a group that intends to file a consolidated return, check here . . . ▶ [X]
If checked, attach a statement listing the name, address, and Employer Identification Number (EIN) for each member covered by this application.

4 If the organization is a corporation or partnership that qualifies under Regulations section 1.6081-5, check here . . ▶ [ ]

5a The application is for calendar year 20 16 , or tax year beginning __________ , 20 ___ , and ending __________ , 20 ___

b Short tax year. If this tax year is less than 12 months, check the reason: [ ] Initial return [ ] Final return
[ ] Change in accounting period [ ] Consolidated return to be filed [ ] Other (see instructions - attach explanation)

6	Tentative total tax. . . .	6	6,000,000.
7	Total payments and credits (see instructions)	7	6,000,000.
8	Balance due. Subtract line 7 from line 6 (see instructions)	8	

SCANA CORPORATION 57-0784499

Form 7004 - Affiliated Group Members

Name	Employer ID	Name	Employer ID
SCANA SERVICES INC	57-1092169	SOUTH CAROLINA ELECTRIC and GAS COMPANY	57-0248695
SOUTH CAROLINA FUEL CO INC	57-0691209	SC GENERATING COMPANY INC	57-0784498
SCANA COMMUNICATIONS HOLDINGS INC	51-0394908	SCANA ENERGY MARKETING INC	57-0850977
SERVICECARE INC	57-1007394	PUBLIC SERVICE COMPANY OF NORTH CAROLINA	56-2128483
CLEAN ENERGY ENTERPRISES INC	56-1078443	PSNC BLUE RIDGE CORPORATION	56-1791764
PSNC CARDINAL PIPELINE COMPANY	56-1955423	SCANA CORPORATE SECURITY SERVICES INC	20-0989017

Statement 1

PRO FORMA

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2016 or tax year beginning ______, ending ______

▶ Information about Form 1120 and its separate instructions is at www.irs.gov/form1120.

OMB No. 1545-0123 **2016**

A Check if: 1a Consolidated return (attach Form 851) [X]; b Life/nonlife consolidated return [ ]; 2 Personal holding co. (attach Sch. PH) [ ]; 3 Personal service corp (see instructions) [ ]; 4 Schedule M-3 attached [X]	TYPE OR PRINT — Name: SCANA CORPORATION; Number, street, and room or suite no. If a P.O. box, see instructions: 220 OPERATION WAY; City or town, state, or province, country, and ZIP or foreign postal code: CAYCE, SC 29033-3701	B Employer identification number: 57-0784499; C Date incorporated: 10/01/1984; D Total assets (see instructions): $ 18,706,879,069.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Section	Line	Description	Sub-line	Sub-amount	Line	Amount
Income	1a	Gross receipts or sales	1a	4,497,365,433.		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	4,497,365,433.
	2	Cost of goods sold (attach Form 1125-A)			2	2,118,180,744.
	3	Gross profit. Subtract line 2 from line 1c			3	2,379,184,689.
	4	Dividends (Schedule C, line 19)			4	337,492.
	5	Interest			5	241,238,458.
	6	Gross rents			6	15,809,392.
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	230,794.
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	-51,771,917.
	10	Other income (see instructions - attach statement)			10	27,496,341.
	11	Total income. Add lines 3 through 10 ▶			11	2,612,525,249.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E) ▶			12	15,144,833.
	13	Salaries and wages (less employment credits)			13	80,503,050.
	14	Repairs and maintenance			14	248,721,590.
	15	Bad debts			15	10,347,235.
	16	Rents			16	4,696,539.
	17	Taxes and licenses			17	256,620,275.
	18	Interest			18	385,177,623.
	19	Charitable contributions			19	NONE
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	674,906,524.
	21	Depletion			21	
	22	Advertising			22	12,485,413.
	23	Pension, profit-sharing, etc., plans			23	694,957.
	24	Employee benefit programs			24	56,802,808.
	25	Domestic production activities deduction (attach Form 8903)			25	
	26	Other deductions (attach statement)			26	923,324,230.
	27	Total deductions. Add lines 12 through 26 ▶			27	2,669,425,077.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11			28	-56,899,828.
	29a	Net operating loss deduction (see instructions)	29a	NONE		
	b	Special deductions (Schedule C, line 20)	29b	212,200.		
	c	Add lines 29a and 29b			29c	212,200.
Tax, Refundable Credits, and Payments	30	Taxable income. Subtract line 29c from line 28. See instructions			30	-57,112,028.
	31	Total tax (Schedule J, Part I, line 11)			31	NONE
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	6,237,866.
	33	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶ [ ]			33	
	34	Amount owed. If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	
	35	Overpayment. If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	6,237,866.
	36	Enter amount from line 35 you want: Credited to 2017 estimated tax ▶ Refunded ▶			36	6,237,866.

Sign Here Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer: JAMES E SWAN IV | Date: 09/28/2017 | Title: CONTROLLER

May the IRS discuss this return with the preparer shown below? See instructions. [ ] Yes [X] No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check [ ] if self-employed	PTIN

Firm's name ▶ | Firm's EIN ▶

Firm's address ▶ | Phone no.

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 2

Schedule C Dividends and Special Deductions (see instructions)	(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	303,143.	70	212,200.
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3 Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Total.** Add lines 1 through 8. See instructions for limitation			212,200.
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members		100	
12 Dividends from certain FSCs		100	
13 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, or 12	34,349.		
14 Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15 Foreign dividend gross-up			
16 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
17 Other dividends			
18 Deduction for dividends paid on certain preferred stock of public utilities			
19 **Total dividends.** Add lines 1 through 17. Enter here and on page 1, line 4 ▶	337,492.		
20 **Total special deductions.** Add lines 9, 10, 11, 12, and 18. Enter here and on page 1, line 29b ▶			212,200.

Form **1120** (2016)

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 3

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ ☐				
2	Income tax. Check if a qualified personal service corporation. See instructions ▶ ☐			2	
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	NONE
5a	Foreign tax credit (attach Form 1118)	5a			
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c			
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	Total credits. Add lines 5a through 5e			6	
7	Subtract line 6 from line 4			7	NONE
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	Total. Add lines 9a through 9f			10	
11	Total tax. Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	NONE

Part II-Payments and Refundable Credits

12	2015 overpayment credited to 2016			12	
13	2016 estimated tax payments			13	6,000,000.
14	2016 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	6,000,000.
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	Total payments. Add lines 15, 16, and 17			18	6,000,000.
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	237,866.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	Total credits. Add lines 19a through 19d			20	237,866.
21	Total payments and credits. Add lines 18 and 20. Enter here and on page 1, line 32			21	6,237,866.

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ HOLDING COMPANY		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 4

Schedule K **Other Information** *(continued from page 3)*

		Yes	No
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851**, Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.		X

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock

		Yes	No
b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital

		Yes	No
6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316. If "Yes," file **Form 5452**, Corporate Report of Nondividend Distributions. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		X
7	At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of (a) the total voting power of all classes of the corporation's stock entitled to vote or (b) the total value of all classes of the corporation's stock? For rules of attribution, see section 318. If "Yes," enter: (i) Percentage owned ▶ ______ and (ii) Owner's country ▶ ______ (c) The corporation may have to file **Form 5472**, Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ ______		X
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐ If checked, the corporation may have to file **Form 8281**, Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $ ______		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶ ______		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here ▶ ☐ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election won't be valid.		
12	Enter the available NOL carryover from prior tax years (don't reduce it by any deduction on line 29a.) ▶ $ ______		
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year and its total assets at the end of the tax year less than $250,000? If "Yes," the corporation isn't required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $ ______		X
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions. If "Yes," complete and attach Schedule UTP.	X	
15a	Did the corporation make any payments in 2016 that would require it to file Form(s) 1099?	X	
b	If "Yes," did or will the corporation file required Forms 1099?	X	
16	During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?	X	

SCANA CORPORATION 57-0784499

Form 1120 (2016) Page 5

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	(b)	End of tax year (c)	(d)
1 Cash		236,349,831.		207,880,557.
2a Trade notes and accounts receivable	682,391,843.		733,184,381.	
b Less allowance for bad debts	(5,269,711.)	677,122,132.	(5,853,608.)	727,330,773.
3 Inventories		311,778,910.		290,480,845.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)		151,782,083.		280,369,350.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)		240,146,412.		198,711,256.
10a Buildings and other depreciable assets	18,667,897,661.		20,054,957,957.	
b Less accumulated depreciation	(5,975,136,607.)	12,692,761,054.	(5,454,272,723.)	14,600,685,234.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)				
13a Intangible assets (amortizable only)				
b Less accumulated amortization	( )		( )	
14 Other assets (attach statement)		2,479,478,762.		2,401,421,054.
15 Total assets		16,789,419,184.		18,706,879,069.
Liabilities and Shareholders' Equity				
16 Accounts payable		576,643,248.		388,631,752.
17 Mortgages, notes, bonds payable in less than 1 year		647,291,449.		957,426,831.
18 Other current liabilities (attach statement)		653,922,195.		719,026,809.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		5,904,834,401.		6,472,928,061.
21 Other liabilities (attach statement)		3,562,331,009.		4,443,834,268.
22 Capital stock: a Preferred stock				
b Common stock	2,417,595,500.	2,417,595,500.	2,417,595,500.	2,417,595,500.
23 Additional paid-in capital		-14,282,362.		-14,282,362.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		3,118,303,738.		3,383,244,353.
26 Adjustments to shareholders' equity (attach statement)		-65,427,485.		-49,050,610.
27 Less cost of treasury stock		(11,792,509.)		(12,475,533.)
28 Total liabilities and shareholders' equity		16,789,419,184.		18,706,879,069.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation . . . $	
a Depreciation . . . $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)

1 Balance at beginning of year	3,118,303,738.	5 Distributions: a Cash	329,908,943.
2 Net income (loss) per books	594,849,551.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize):	-5.
	2.	7 Add lines 5 and 6	329,908,938.
4 Add lines 1, 2, and 3	3,713,153,291.	8 Balance at end of year (line 4 less line 7)	3,383,244,353.

Form **1120** (2016)

SCHEDULE M-3 (Form 1120)
Department of the Treasury
Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ Attach to Form 1120 or 1120-C. ▶ Information about Schedule M-3 (Form 1120) and its separate instructions is available at *www.irs.gov/form1120*.

OMB No. 1545-0123
2016

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Non-consolidated return (2) [X] Consolidated return (Form 1120 only)
(3) [ ] Mixed 1120/L/PC group (4) [ ] Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
[X] Yes. Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
[ ] No. Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
[ ] Yes. *Skip line 1c and complete lines 2a through 11 with respect to that income statement.*
[ ] No. Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
[ ] Yes. Complete lines 2a through 11 with respect to that income statement.
[ ] No. Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 01/01/2016 Ending 12/31/2016

b Has the corporation's income statement been restated for the income statement period on line 2a?
[ ] Yes. (If "Yes," attach an explanation and the amount of each item restated.)
[X] No.

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
[ ] Yes. (If "Yes," attach an explanation and the amount of each item restated.)
[X] No.

3 a Is any of the corporation's voting common stock publicly traded?
[X] Yes.
[ ] No. If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock: SCG

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock: 80589M102

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	4a	594,849,551.
b	Indicate accounting standard used for line 4a (see instructions): (1) [X] GAAP (2) [ ] IFRS (3) [ ] Statutory (4) [ ] Tax-basis (5) [ ] Other (specify)		
5 a	Net income from nonincludible foreign entities (attach statement)	5a	( )
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount)	5b	
6 a	Net income from nonincludible U.S. entities (attach statement)	6a	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	6b	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	7a	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement)	7b	
c	Net income (loss) of other includible entities (attach statement)	7c	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	8	
9	Adjustment to reconcile income statement period to tax year (attach statement)	9	
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	10a	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	10b	
c	Other adjustments to reconcile to amount on line 11 (attach statement)	10c	
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	11	594,849,551.

Note. Part I, line 11, must equal Part II, line 30, column (a) or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

	Total Assets	Total Liabilities
a Included on Part I, line 4 ▶	18,706,879,069.	12,981,847,72[illegible].
b Removed on Part I, line 5 ▶		
c Removed on Part I, line 6 ▶		
d Included on Part I, line 7 ▶		

Schedule M-3 (Form 1120) 2016 Page **2**

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)

Employer identification number

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed		34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	3,751,723.	954,029.		4,705,752.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	-2,299,688.	-1,380,838.		-3,680,526.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	40,236,868.	201,001,590.		241,238,458.
14 Total accrual to cash adjustment				
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(2,169,000,078.)	72,440,739.		(2,096,559,339.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	566,889.	-566,889.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities		235,773.		235,773.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-4,979.		-4,979.
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-51,771,917.		-51,771,917.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	4,348,156,767.	24,580,638.	222,694.	4,372,960,099.
26 Total income (loss) items. Combine lines 1 through 25	2,200,042,197.	245,574,517.	222,694.	2,445,839,408.
27 Total expense/deduction items (from Part II, line 38)	-1,613,822,773.	-1,114,100,827.	216,554,237.	-2,511,369,363.
28 Other items with no differences	8,630,127.			8,630,127.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	594,849,551.	-868,526,310.	216,776,931.	-56,899,828.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	594,849,551.	-868,526,310.	216,776,931.	-56,899,828.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)

Employer identification number

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	35,319,589.		-35,319,589.	
2 U.S. deferred income tax expense	201,531,407.		-201,531,407.	
3 State and local current income tax expense	12,961,624.	-11,298,538.		1,663,086.
4 State and local deferred income tax expense	20,908,859.	-20,908,859.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	342,269,370.	42,908,253.		385,177,623.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	2,833,057.		-1,501,983.	1,331,074.
12 Fines and penalties	-346,594.		346,594.	
13 Judgments, damages, awards, and similar costs	9,343,483.	-2,378,759.		6,964,724.
14 Parachute payments				
15 Compensation with section 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.
16 Pension and profit-sharing	24,499,724.	-23,804,767.		694,957.
17 Other post-retirement benefits	61,069,682.	-4,266,874.		56,802,808.
18 Deferred compensation	4,528,916.	-4,528,916.		
19 Charitable contribution of cash and tangible property	3,083,562.	497,595.	4,582.	3,585,739.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	4,391,015.	7,212,662.		11,603,677.
29 Reserved				
30 Depletion				
31 Depreciation	352,117,080.	322,789,444.		674,906,524.
32 Bad debt expense	10,931,132.	-583,897.		10,347,235.
33 Corporate owned life insurance premiums	-624,899.		624,899.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		722,622,385.		722,622,385.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	511,355,651.	85,841,098.	26,913,688.	624,110,437.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,613,822,773.	1,114,100,827.	-216,554,237.	2,511,369,363.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed		34,349.		34,349.
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations	612,397,274.		-612,397,274.	
7 U.S. dividends not eliminated in tax consolidation		303,143.		303,143.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities		-33,798.		-33,798.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	9,922,963.	-1,366,405.		8,556,558.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities		235,773.		235,773.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-4,979.		-4,979.
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	622,320,237.	-831,917.	-612,397,274.	9,091,046.
27 Total expense/deduction items (from Part III, line 38)	-28,096,287.	6,603,298.	-53,237,447.	-74,730,436.
28 Other items with no differences	-136,909.			-136,909.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	594,087,041.	5,771,381.	-665,634,721.	-65,776,299.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	594,087,041.	5,771,381.	-665,634,721.	-65,776,299.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-21,613,000.		21,613,000.	
2 U.S. deferred income tax expense	-3,623,000.		3,623,000.	
3 State and local current income tax expense	-3,261,300.	3,261,300.		
4 State and local deferred income tax expense	-544,700.	544,700.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	54,743,724.	-3,597.		54,740,127.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	170,908.		-170,908.	
12 Fines and penalties	-350,900.		350,900.	
13 Judgments, damages, awards, and similar costs		44,555.		44,555.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	481,120.	-1,983,346.		-1,502,226.
17 Other post-retirement benefits	-49,835.	-2,846,314.		-2,896,149.
18 Deferred compensation	4,528,916.	-4,528,916.		
19 Charitable contribution of cash and tangible property		145.		145.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums	-662,284.		662,284.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	-1,723,362.	-1,091,825.	27,159,171.	24,343,984.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	28,096,287.	-6,603,298.	53,237,447.	74,730,436.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA SERVICES INC

Employer identification number: 57-1092169

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	730,796.			730,796.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(74,318,188.)			(74,318,188.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-696,096.		-696,096.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-73,587,392.	-696,096.		-74,283,488.
27 Total expense/deduction items (from Part III, line 38)	-228,778,968.	11,381,801.		-217,397,167.
28 Other items with no differences	302,366,360.			302,366,360.
29a Mixed groups, see instructions. All others, combine lines 26 through 28		10,685,705.		10,685,705.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c		10,685,705.		10,685,705.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SCANA SERVICES INC	57-1092169

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	5,064,100.		-5,064,100.	
2 U.S. deferred income tax expense	-5,064,100.		5,064,100.	
3 State and local current income tax expense	848,600.	-838,600.		10,000.
4 State and local deferred income tax expense	-848,600.	848,600.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	9,119,174.			9,119,174.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	5,113,014.	-522,071.		4,590,943.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	364,871.			364,871.
17 Other post-retirement benefits	29,670,928.			29,670,928.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	3,396,707.	-1,257,589.		2,139,118.
29 Reserved				
30 Depletion				
31 Depreciation	12,610,493.	3,229,767.		15,840,260.
32 Bad debt expense	57,907.			57,907.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		882,125.		882,125.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	168,445,874.	-13,724,033.		154,721,841.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	228,778,968.	-11,381,801.		217,397,167.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA ELECTRIC and GAS COMPANY

Employer identification number: 57-0248695

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	-3,486,238.	-1,347,040.		-4,833,278.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	32,004,614.	203,397,097.		235,401,711.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(1,104,945,601.)	16,634,798.		(1,088,310,803.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	621,436.	-621,436.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-38,024,208.		-38,024,208.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	2,974,321,805.	24,317,336.	60,389.	2,998,699,530.
26 Total income (loss) items. Combine lines 1 through 25	1,898,516,016.	204,356,547.	60,389.	2,102,932,952.
27 Total expense/deduction items (from Part III, line 38)	-1,155,512,001.	-959,826,350.	212,981,318.	-1,902,357,033.
28 Other items with no differences	-230,312,531.			-230,312,531.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	512,691,484.	-755,469,803.	213,041,707.	-29,736,612.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	512,691,484.	-755,469,803.	213,041,707.	-29,736,612.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA ELECTRIC and GAS COMPANY
Employer identification number: 57-0248695

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	45,571,465.		-45,571,465.	
2 U.S. deferred income tax expense	163,658,014.		-163,658,014.	
3 State and local current income tax expense	11,734,524.	-11,734,524.		
4 State and local deferred income tax expense	19,251,854.	-19,251,854.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	254,693,671.	42,604,735.		297,298,406.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	2,002,874.		-1,001,437.	1,001,437.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	7,729,228.	-1,922,201.		5,807,027.
14 Parachute payments				
15 Compensation with section 162(m) limitation	17,650,115.		-2,505,282.	15,144,833.
16 Pension and profit-sharing	20,973,512.	-19,604,703.		1,368,809.
17 Other post-retirement benefits	44,703,978.	-1,089,215.		43,614,763.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	2,255,999.	478,374.	2,177.	2,736,550.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs		8,116,771.		8,116,771.
29 Reserved				
30 Depletion				
31 Depreciation	268,849,610.	163,071,582.		431,921,192.
32 Bad debt expense	6,625,659.	-275,701.		6,349,958.
33 Corporate owned life insurance premiums	28,544.		-28,544.	
34 Purchase versus lease *(for purchasers and/or lessees)*				
35 Research and development costs		721,608,322.		721,608,322.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	289,782,954.	77,824,764.	-218,753.	367,388,965.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,155,512,001.	959,826,350.	-212,981,318.	1,902,357,033.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SOUTH CAROLINA FUEL CO INC

Employer identification number: 57-0691209

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(235,135,917.)	55,780,868.		(179,355,049.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-235,135,917.	55,780,868.		-179,355,049.
27 Total expense/deduction items (from Part III, line 38)	-1,846,341.	-46,060,920.		-47,907,261.
28 Other items with no differences	236,982,258.			236,982,258.
29a Mixed groups, see instructions. All others, combine lines 26 through 28		9,719,948.		9,719,948.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c		9,719,948.		9,719,948.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SOUTH CAROLINA FUEL CO INC	57-0691209

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	3,232,500.		-3,232,500.	
2 U.S. deferred income tax expense	-3,232,500.		3,232,500.	
3 State and local current income tax expense	486,100.	-486,100.		
4 State and local deferred income tax expense	-486,100.	486,100.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	1,845,292.			1,845,292.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	11.			11.
17 Other post-retirement benefits	1,038.			1,038.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation		46,060,920.		46,060,920.
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,846,341.	46,060,920.		47,907,261.

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SC GENERATING COMPANY INC

Employer identification number: 57-0784498

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	54,046.	-31,785.		22,261.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(113,725,200.)			(113,725,200.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-3,530,135.		-3,530,135.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-113,671,154.	-3,561,920.		-117,233,074.
27 Total expense/deduction items (from Part III, line 38)	-55,762,783.	-6,888,802.	6,916,462.	-55,735,123.
28 Other items with no differences	182,523,825.			182,523,825.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	13,089,888.	-10,450,722.	6,916,462.	9,555,628.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	13,089,888.	-10,450,722.	6,916,462.	9,555,628.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SC GENERATING COMPANY INC

Employer identification number: 57-0784498

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	1,526,840.		-1,526,840.	
2 U.S. deferred income tax expense	5,390,460.		-5,390,460.	
3 State and local current income tax expense	344,200.	-344,200.		
4 State and local deferred income tax expense	803,400.	-803,400.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	15,345,851.	-482,617.		14,863,234.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	744.		-372.	372.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	177,603.	20,908.		198,511.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	19,491.			19,491.
17 Other post-retirement benefits	1,568,904.			1,568,904.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	10,012.		2,405.	12,417.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	139,749.	-37,956.		101,793.
29 Reserved				
30 Depletion				
31 Depreciation	18,359,883.	1,230,464.		19,590,347.
32 Bad debt expense				
33 Corporate owned life insurance premiums	1,195.		-1,195.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	12,074,451.	7,305,603.		19,380,054.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	55,762,783.	6,888,802.	-6,916,462.	55,735,123.

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA COMMUNICATIONS HOLDINGS INC

Employer identification number: 51-0394908

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities	1,186,550.			1,186,550.
12 Items relating to reportable transactions				
13 Interest income (see instructions)	6,321.			6,321.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	1,192,871.			1,192,871.
27 Total expense/deduction items (from Part III, line 38)	-410,284.		410,284.	
28 Other items with no differences	-20,631.			-20,631.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	761,956.		410,284.	1,172,240.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	761,956.		410,284.	1,172,240.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA COMMUNICATIONS HOLDINGS INC
Employer identification number: 51-0394908

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	410,284.		-410,284.	
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	410,284.		-410,284.	

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Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
SCANA ENERGY MARKETING INC	57-0850977

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	374,179.			374,179.
14 Total accrual to cash adjustment				
15 Hedging transactions	-21,370,284.	-251,121.		-21,621,405.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(812,053,946.)	-77,007.		(812,130,953.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	1,646.	-1,646.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		1,646.		1,646.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	938,014,128.	263,302.		938,277,430.
26 Total income (loss) items. Combine lines 1 through 25	104,965,723.	-64,826.		104,900,897.
27 Total expense/deduction items (from Part III, line 38)	-49,810,799.	2,042,244.	16,396,483.	-31,372,072.
28 Other items with no differences	-25,341,670.			-25,341,670.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	29,813,254.	1,977,418.	16,396,483.	48,187,155.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	29,813,254.	1,977,418.	16,396,483.	48,187,155.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA ENERGY MARKETING INC

Employer identification number: 57-0850977

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	15,814,300.		-15,814,300.	
2 U.S. deferred income tax expense	382,600.		-382,600.	
3 State and local current income tax expense	2,385,200.	-1,128,598.		1,256,602.
4 State and local deferred income tax expense	32,200.	-32,200.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	1,070,855.			1,070,855.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	384,040.		-192,020.	192,020.
12 Fines and penalties	4,306.		-4,306.	
13 Judgments, damages, awards, and similar costs	77,812.	3,175.		80,987.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	1,007,820.	-954,780.		53,040.
17 Other post-retirement benefits	4,442,895.	-121,580.		4,321,315.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	446,898.	6,536.		453,434.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs	854,559.	244,088.		1,098,647.
29 Reserved				
30 Depletion				
31 Depreciation	237,169.	718,134.		955,303.
32 Bad debt expense	3,837,358.	-408,199.		3,429,159.
33 Corporate owned life insurance premiums	3,257.		-3,257.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs		131,938.		131,938.
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	18,829,530.	-500,758.		18,328,772.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	49,810,799.	-2,042,244.	-16,396,483.	31,372,072.

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Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SERVICECARE INC

Employer identification number: 57-1007394

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	5,863.			5,863.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	5,863.			5,863.
27 Total expense/deduction items (from Part III, line 38)	10,393.	-1,168,109.	-8,400.	-1,166,116.
28 Other items with no differences	-31,927.			-31,927.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-15,671.	-1,168,109.	-8,400.	-1,192,180.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	-15,671.	-1,168,109.	-8,400.	-1,192,180.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SERVICECARE INC

Employer identification number: 57-1007394

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-401,900.		401,900.	
2 U.S. deferred income tax expense	393,500.		-393,500.	
3 State and local current income tax expense	-60,400.	60,400.		
4 State and local deferred income tax expense	59,000.	-59,000.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs		3,709.		3,709.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing		849,150.		849,150.
17 Other post-retirement benefits		313,850.		313,850.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense	-593.			-593.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-10,393.	1,168,109.	8,400.	1,166,116.

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORATED

Employer identification number: 56-2128483

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	6,572,645.	-1,013,022.		5,559,623.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(205,178,315.)	102,080.		(205,076,235.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	-56,193.	56,193.		
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-9,523,124.		-9,523,124.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	435,820,834.		162,305.	435,983,139.
26 Total income (loss) items. Combine lines 1 through 25	237,158,971.	-10,377,873.	162,305.	226,943,403.
27 Total expense/deduction items (from Part III, line 38)	-147,379,356.	-119,881,825.	28,136,365.	-239,124,816.
28 Other items with no differences	-35,495,924.			-35,495,924.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	54,283,691.	-130,259,698.	28,298,670.	-47,677,337.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	54,283,691.	-130,259,698.	28,298,670.	-47,677,337.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

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Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PUBLIC SERVICE COMPANY OF NORTH CAROLINA INCORPORATED

Employer identification number: 56-2128483

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-15,947,900.		15,947,900.	
2 U.S. deferred income tax expense	43,915,900.		-43,915,900.	
3 State and local current income tax expense	328,400.	-29,985.		298,415.
4 State and local deferred income tax expense	3,002,200.	-3,002,200.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	25,177,074.	789,732.		25,966,806.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment	274,491.		-137,246.	137,245.
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	1,358,840.	-6,834.		1,352,006.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	2,017,770.	-2,111,088.		-93,318.
17 Other post-retirement benefits	10,402,702.	-523,615.		9,879,087.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	370,653.	12,540.		383,193.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs		147,348.		147,348.
29 Reserved				
30 Depletion				
31 Depreciation	52,059,925.	108,478,577.		160,538,502.
32 Bad debt expense	468,708.	100,003.		568,711.
33 Corporate owned life insurance premiums	4,389.		-4,389.	
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	23,946,204.	16,027,347.	-26,730.	39,946,821.
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	147,379,356.	119,881,825.	-28,136,365.	239,124,816.

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): CLEAN ENERGY ENTERPRISES INC

Employer identification number: 56-1078443

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25				
27 Total expense/deduction items (from Part III, line 38)	400.		-400.	
28 Other items with no differences	-1,703.			-1,703.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-1,303.		-400.	-1,703.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	-1,303.		-400.	-1,703.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): CLEAN ENERGY ENTERPRISES INC

Employer identification number: 56-1078443

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-400.		400.	
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-400.		400.	

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Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
PSNC BLUE RIDGE CORPORATION	56-1791764

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	1,138,536.	476,903.		1,615,439.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)		3,557.		3,557.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	1,138,536.	480,460.		1,618,996.
27 Total expense/deduction items (from Part III, line 38)	-361,751.	-89,746.	411,026.	-40,471.
28 Other items with no differences	-10,900.			-10,900.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	765,885.	390,714.	411,026.	1,567,625.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	765,885.	390,714.	411,026.	1,567,625.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PSNC BLUE RIDGE CORPORATION

Employer identification number: 56-1791764

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	507,200.		-507,200.	
2 U.S. deferred income tax expense	-96,174.		96,174.	
3 State and local current income tax expense	68,200.	-27,729.		40,471.
4 State and local deferred income tax expense	-117,475.	117,475.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	361,751.	89,746.	-411,026.	40,471.

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PSNC CARDINAL PIPELINE COMPANY

Employer identification number: 56-1955423

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	2,613,187.	477,126.		3,090,313.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)		12,148.		12,148.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	2,613,187.	489,274.		3,102,461.
27 Total expense/deduction items (from Part III, line 38)	-807,987.	-212,418.	962,807.	-57,598.
28 Other items with no differences	-34,600.			-34,600.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	1,770,600.	276,856.	962,807.	3,010,263.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	1,770,600.	276,856.	962,807.	3,010,263.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): PSNC CARDINAL PIPELINE COMPANY

Employer identification number: 56-1955423

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	1,156,100.		-1,156,100.	
2 U.S. deferred income tax expense	-193,293.		193,293.	
3 State and local current income tax expense	88,100.	-30,502.		57,598.
4 State and local deferred income tax expense	-242,920.	242,920.		
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	807,987.	212,418.	-962,807.	57,598.

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Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATE SECURITY SERVICES INC
Employer identification number: 20-0989017

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25				
27 Total expense/deduction items (from Part III, line 38)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28				
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c				

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION
Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [X] Subsidiary corp (5) [ ] Mixed 1120/L/PC group
Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): SCANA CORPORATE SECURITY SERVICES INC
Employer identification number: 20-0989017

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive				

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return)	Employer identification number
SCANA CORPORATION	57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [X] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return)	Employer identification number
ELIMINATIONS SCANA CORPORATIO	

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations	-612,397,274.		612,397,274.	
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	-9,434,559.			-9,434,559.
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(-376,357,089.)			(-376,357,089.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25	-245,474,744.		612,397,274.	366,922,530.
27 Total expense/deduction items (from Part III, line 38)	54,932,991.			54,932,991.
28 Other items with no differences	-421,855,521.			-421,855,521.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-612,397,274.		612,397,274.	
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c	-612,397,274.		612,397,274.	

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page 3

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [X] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): ELIMINATIONS SCANA CORPORATIO

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	-19,726,271.			-19,726,271.
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs	-5,113,014.			-5,113,014.
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing	-364,871.			-364,871.
17 Other post-retirement benefits	-29,670,928.			-29,670,928.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense	-57,907.			-57,907.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-54,932,991.			-54,932,991.

Schedule M-3 (Form 1120) 2016

Schedule M-3 (Form 1120) 2016 Page 2

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): Adjustments

Employer identification number:

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 Total income (loss) items. Combine lines 1 through 25				
27 Total expense/deduction items (from Part III, line 38)			3,585,739.	3,585,739.
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28			3,585,739.	3,585,739.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 Reconciliation totals. Combine lines 29a through 29c			3,585,739.	3,585,739.

Note. Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2016 Page **3**

Name of corporation (common parent, if consolidated return): SCANA CORPORATION

Employer identification number: 57-0784499

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [ ] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): Adjustments

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense				
2 U.S. deferred income tax expense				
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)				
9 Stock option expense				
10 Other equity-based compensation				
11 Meals and entertainment				
12 Fines and penalties				
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation				
16 Pension and profit-sharing				
17 Other post-retirement benefits				
18 Deferred compensation				
19 Charitable contribution of cash and tangible property				
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward			-3,585,739.	-3,585,739.
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill				
27 Amortization of acquisition, reorganization, and start-up costs				
28 Other amortization or impairment write-offs				
29 Reserved				
30 Depletion				
31 Depreciation				
32 Bad debt expense				
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)				
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)				
38 Total expense/deduction items. Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive			-3,585,739.	-3,585,739.

Schedule M-3 (Form 1120) 2016

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Form **851** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Affiliations Schedule

For tax year ending 12/31/2016

▶File with each consolidated income tax return.

▶ Information about Form 851 and its instructions is at *www.irs.gov/form851*.

OMB No. 1545-0123

Name of common parent corporation	Employer identification number
SCANA CORPORATION	57-0784499

Number, street, and room or suite no. If a P.O. box, see instructions.

220 OPERATION WAY

City or town, state, and ZIP code

CAYCE, SC 29033-3701

Part I **Overpayment Credits, Estimated Tax Payments, and Tax Deposits** (see instructions)

Corp. No.	Name and address of corporation	Employer identification number	Portion of overpayment credits and estimated tax payments	Portion of tax deposited with Form 7004
1	Common parent corporation		6,000,000.	
	Subsidiary corporations:			
2	SCANA SERVICES INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-1092169		
3	SOUTH CAROLINA ELECTRIC and GAS COMPANY 220 OPERATION WAY CAYCE, SC 29033-3701	57-0248695		
4	SOUTH CAROLINA FUEL CO INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0691209		
5	SC GENERATING COMPANY INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0784498		
6	SCANA COMMUNICATIONS HOLDINGS INC 1011 CENTRE ROAD SUITE 322 WILMINGTON, DE 19805	51-0394908		
7	SCANA ENERGY MARKETING INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-0850977		
	Totals (Must equal amounts shown on the consolidated tax return.) . . . . ▶		6,000,000.	

Part II **Principal Business Activity, Voting Stock Information, Etc.** (see instructions)

Corp. No.	Principal business activity (PBA)	PBA Code No.	Did the subsidiary make any nondividend distributions? Yes	No	Stock holdings at beginning of year: Number of shares	Percentage of voting power	Percentage of value	Owned by corporation no.
1	Common parent corporation HOLDING COMPANY	551112						
	Subsidiary corporations:							
2	SERVICES	541990		X	1,000	100.00 %	100.00%	1
3	UTILITY	221100		X	40,296,147	100.00 %	100.00%	1
4	WHOLESALE	423520		X	1	100.00 %	100.00%	1
5	Utility	221112		X	1	100.00 %	100.00%	1
6	OTHER INVESTMENT ACTIVITY	523999		X	1	100.00 %	100.00%	1
7	MARKETING	221210		X	1	100.00 %	100.00%	1

Form **851** (Rev. October 2016) Department of the Treasury Internal Revenue Service

Affiliations Schedule

For tax year ending 12/31/2016

▶File with each consolidated income tax return.

▶ Information about Form 851 and its instructions is at *www.irs.gov/form851*.

OMB No. 1545-0123

Name of common parent corporation: SCANA CORPORATION

Employer identification number: 57-0784499

Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY

City or town, state, and ZIP code: CAYCE, SC 29033-3701

Part I Overpayment Credits, Estimated Tax Payments, and Tax Deposits (see instructions)

Corp. No.	Name and address of corporation	Employer identification number	Portion of overpayment credits and estimated tax payments	Portion of tax deposited with Form 7004
	Common parent corporation			
	Subsidiary corporations:			
8	SERVICECARE INC 220 OPERATION WAY CAYCE, SC 29033-3701	57-1007394		
9	PUBLIC SERVICE COMPANY OF NORTH CAROLINA 220 OPERATION WAY CAYCE, SC 29033-3701	56-2128483		
10	CLEAN ENERGY ENTERPRISES INC 220 OPERATION WAY CAYCE, SC 29033-3701	56-1078443		
11	PSNC BLUE RIDGE CORPORATION 220 OPERATION WAY CAYCE, SC 29033-3701	56-1791764		
12	PSNC CARDINAL PIPELINE COMPANY 220 OPERATION WAY CAYCE, SC 29033-3701	56-1955423		
13	SCANA CORPORATE SECURITY SERVICES INC 220 OPERATION WAY CAYCE, SC 29033-3701	20-0989017		
	Totals (Must equal amounts shown on the consolidated tax return.) ▶			

Part II Principal Business Activity, Voting Stock Information, Etc. (see instructions)

Corp. No.	Principal business activity (PBA)	PBA Code No.	Did the subsidiary make any nondividend distributions? Yes	No	Stock holdings at beginning of year: Number of shares	Percentage of voting power	Percentage of value	Owned by corporation no.
	Common parent corporation							
	Subsidiary corporations:							
8	SERVICES	811412		X	1,000	100.00 %	100.00%	1
9	NATURAL GAS DISTRIBUTION	221210		X	1,000	100.00 %	100.00%	1
10	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00%	9
11	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00%	9
12	NATURAL GAS DISTRIBUTION	221210		X	1	100.00 %	100.00%	9
13	SERVICES	541990		X	1,000	100.00 %	100.00%	1

FEDERAL ATTACHMENT

Part III Changes in Stock Holdings During the Tax Year

Corp. No.	Name of corporation	Share-holder of Corpora-tion No.	Date of transaction	(a) Changes: Number of shares acquired	(a) Changes: Number of shares disposed of	(b) Shares held after changes described in column (a): Percentage of voting power	(b) Percentage of value
8	SERVICECARE INC	1	12/20/2016		1,000	%	%
						%	%
						%	%
						%	%
						%	%
						%	%
						%	%
						%	%

(c) If any transaction listed above caused a transfer of a share of subsidiary stock (defined to include dispositions and deconsolidations), did the share's basis exceed its value at the time of the transfer? See instructions . . . . ☐ Yes ☒ No

(d) Did any share of subsidiary stock become worthless within the meaning of section 165 (taking into account the provisions of Regulations section 1.1502-80(c)) during the taxable year? See instructions . . . . . . ☐ Yes ☒ No

(e) If the equitable owners of any capital stock shown above were other than the holders of record, provide details of the changes.

(f) If additional stock was issued, or if any stock was retired during the year, list the dates and amounts of these transactions.

Form 851 (Rev. 10-2016) Page 3

Part IV **Additional Stock Information** (see instructions)

1 During the tax year, did the corporation have more than one class of stock outstanding? . . . . [X] Yes [ ] No

If "Yes," enter the name of the corporation and list and describe each class of stock.

Corp. No.	Name of corporation	Class of stock
3	SOUTH CAROLINA ELECTRIC and GAS COMPANY	COMMON AND PREFERRED 1000 SHS

2 During the tax year, was there any member of the consolidated group that reaffiliated within 60 months of disaffiliation? . . . . [ ] Yes [X] No

If "Yes," enter the name of the corporation(s) and explain the circumstances.

Corp. No.	Name of corporation	Explanation

3 During the tax year, was there any arrangement in existence by which one or more persons that were not members of the affiliated group could acquire any stock, or acquire any voting power without acquiring stock, in the corporation, other than a de minimis amount, from the corporation or another member of the affiliated group? . . . . [ ] Yes [X] No

If "Yes," enter the name of the corporation and see the instructions for the percentages to enter in columns (a), (b), and (c).

Corp. No.	Name of corporation	(a) Percentage of value	(b) Percentage of outstanding voting stock	(c) Percentage of voting power
		%	%	%
		%	%	%
		%	%	%
		%	%	%

Corp. No.	(d) Provide a description of any arrangement.

Form **851** (Rev 10-2016)

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Attachment A

South Carolina Electric & Gas Company
Cash Working Capital Allowance
Twelve Months Ending September 30, 2017

Line No	Description	Total Company-Electric Regulatory Per Books (1) $	Total Company-Electric Acct. & Pro Forma Adjs. (2) $	Total Company-Electric As Adjusted (3) $	F.E.R.C. Wholesale-Electric Regulatory Per Books (4) $	F.E.R.C. Wholesale-Electric Acct. & Pro Forma Adjs. (5) $	F.E.R.C. Wholesale-Electric As Adjusted (6) $	Retail Electric Regulatory Per Books (7) $	Retail Electric Acct. & Pro Forma Adjs. (8) $	Retail Electric As Adjusted (9) $
1.	Operation and Maintenance Expenses									
2.	Fuel Used in Electric Generation	649,424,435	0	649,424,435	26,137,271	0	26,137,271	623,287,164	0	623,287,164
3.	Purchased Power	96,105,480	0	96,105,480	3,089,591	0	3,089,591	93,015,889	0	93,015,889
4.	Other	502,073,959	4,840,606	506,914,565	11,378,237	448,566	11,826,803	490,695,722	4,392,040	495,087,762
5.	Total O & M Expenses	1,247,603,874	4,840,606	1,252,444,480	40,605,099	448,566	41,053,665	1,206,998,775	4,392,040	1,211,390,815
6.	Less: P & I, Fuel Acct 518	301,488,907	0	301,488,907	11,433,569	0	11,433,569	290,055,338	0	290,055,338
7.	Net O & M Expenses	946,114,967	4,840,606	950,955,573	29,171,530	448,566	29,620,096	916,943,437	4,392,040	921,335,477
8.	1/8 of O & M Expenses	118,264,371	605,075	118,869,446	3,646,441	56,070	3,702,511	114,617,930	549,005	115,166,935
9.	Add: Prepayments	84,883,295	0	84,883,295	321,867	0	321,867	84,561,428	0	84,561,428
10.	Less: Customer Deposits	(54,354,631)	0	(54,354,631)	0	0	0	(54,354,631)	0	(54,354,631)
11.	Less: Injuries & Damages	(8,586,287)	0	(8,586,287)	(178,555)	0	(178,555)	(8,407,732)	0	(8,407,732)
12.	Less: Nuclear Refueling	(1,760,363)	0	(1,760,363)	(71,647)	0	(71,647)	(1,688,716)	0	(1,688,716)
13.	Less: Average Tax Accruals	(118,015,305)	0	(118,015,305)	(761,500)	0	(761,500)	(117,253,805)	0	(117,253,805)
14.	Cash Working Capital Allowance	20,431,080	605,075	21,036,155	2,956,606	56,070	3,012,676	17,474,474	549,005	18,023,479

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
EG Corporate								
Common								
EG 390 Structures & Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EG 6927 Trailers, Common	$16,179.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$16,179.03
Depr Summ2 Subtotal:	$16,179.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$16,179.03
Common Intangible								
EG 603 Software, Common	$65,458,932.22	$3,650,978.24	$26,881,389.96)	$0.00	$0.00	$0.00	$0.00	$42,228,520.50
EG 603 Software, Common, CIPV5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EG 603 Software, Common, CIS	$53,652,031.38	$239,539.48	$0.00	$0.00	$0.00	$0.00	$0.00	$53,891,570.86
Depr Summ2 Subtotal:	$119,110,963.60	$3,890,517.72	$26,881,389.96)	$0.00	$0.00	$0.00	$0.00	$96,120,091.36
Non-depreciable								
EG 6891 Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EG 6892 Land Rights & Easements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
None								
EG 6901 Struct & Imp - Office	$25,462,567.33	$2,563,813.57	($109,839.48)	($13,700.00)	$0.00	$121.40	$0.00	$27,902,962.82
EG 69011 Struct & Imp - OSC 12th St	$6,921,554.41	$545,287.44	$0.00	$0.00	$0.00	$0.00	$0.00	$7,466,841.85
EG 6902 Struct & Imp - Warehouse	$5,190,483.71	$487,881.09	$0.00	$0.00	$0.00	$0.00	$0.00	$5,678,364.80
EG 6908 Struct & Imp -Office Lease	$645,177.26	$30,732.62	$0.00	$0.00	$0.00	$0.00	$0.00	$675,909.88
EG 69081 Struct & Imp -Off Lease	$2,128,822.98	$229,044.41	$0.00	$0.00	$0.00	$0.00	$0.00	$2,357,867.39
EG 69082 Struct & Imp -Off Lease	$287,313.09	$38,307.00	$0.00	$0.00	$0.00	$0.00	$0.00	$325,620.09
EG 6909 Struct & Imp -Warehouse	$92,190.66	$5,604.60	$0.00	$0.00	$0.00	$0.00	$0.00	$97,795.26
EG 6911 Office Furniture & Equip	$4,066,451.13	$511,258.16	($135,452.75)	$0.00	$0.00	($150,222.58)	$0.00	$4,292,033.96
EG 6912 EDP Equip 2004 and post	($230,615.60)	$361,759.47	($961,421.75)	$0.00	$0.00	$150,222.58	$0.00	($680,055.30)
EG 6912 EDP Equipment CIPV5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EG 6913 Data Handling Equipment	$970,510.79	$43,185.40	($25,091.05)	$0.00	$0.00	$0.00	$0.00	$988,605.14
EG 6914 EDP (SCPSC ORDER) Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EG 693 Stores	$53,397.35	$364.00	($54,391.76)	$0.00	$0.00	$630.41	$0.00	$0.00
EG 6941 Tools, Shop & Garage - PT	$5,342.04	$275.64	($889.49)	$0.00	$0.00	($630.41)	$0.00	$4,097.78
EG 6943 Tools, Shop & Garage - ST	$229,235.99	$15,486.90	($3,887.12)	$0.00	$0.00	$0.00	$0.00	$240,835.77
EG 6944 Tools, Shop & Garage - GAR	$869,329.84	$95,586.96	($182,657.29)	$0.00	$0.00	$0.00	$0.00	$782,259.51
EG 6952 Laboratory Equip - Other	$57,915.56	$1,099.44	$0.00	$0.00	$0.00	$0.00	$0.00	$59,015.00

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
EG Corporate								
None								
EG 6953 Laboratory Equip - Field	$70,724.22	$3,924.06	($3,854.99)	$0.00	$0.00	$0.00	$0.00	$70,793.29
EG 697 Communication Equipment	$4,111,852.81	$1,249,670.84	($1,442,076.24)	($1,242.30)	$0.00	$0.00	$0.00	$3,918,205.11
EG 697.8 Commun Equip-Leasehold	$409,232.48	$125,424.82	$0.00	$0.00	$0.00	$0.00	$0.00	$534,657.30
EG 698 Miscellaneous Equip CIPV5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EG 698 Miscellaneous Equipment	$3,239,429.04	$446,134.45	($222,801.77)	($440.00)	$0.00	$0.00	$0.00	$3,462,321.72
Depr Summ2 Subtotal:	$54,580,915.09	$6,754,840.87	($3,142,363.69)	($15,382.30)	$0.00	$121.40	$0.00	$58,178,131.37
Company Subtotal:	$173,708,057.72	$10,645,358.59	$30,023,753.65)	($15,382.30)	$0.00	$121.40	$0.00	$154,314,401.76
Fleet Maintenance								
Common								
FL 692 Vehicles, Common	$4,642,486.24	$430,651.21	($430,033.06)	$0.00	$85,596.00	$0.00	($39,438.70)	$4,689,261.69
FL 696 Power Oper Eq, Common	$1,796,168.19	$177,932.54	($86,750.67)	$0.00	$16,530.00	$0.00	($7,854.93)	$1,896,025.13
Depr Summ2 Subtotal:	$6,438,654.43	$608,583.75	($516,783.73)	$0.00	$102,126.00	$0.00	($47,293.63)	$6,585,286.82
Electric FL								
FL 392 Vehicles, Electric	$12,528,763.58	$1,107,856.53	($725,829.88)	$0.00	$119,929.88	$0.00	($45,468.16)	$12,985,251.95
FL 396 Power Oper Eq, Electric	$27,981,901.22	$1,847,514.42	($6,042,598.89)	$0.00	$506,823.15	$0.00	$66,216.17	$24,359,856.07
Depr Summ2 Subtotal:	$40,510,664.80	$2,955,370.95	($6,768,428.77)	$0.00	$626,753.03	$0.00	$20,748.01	$37,345,108.02
None								
FL 694 Garage Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Company Subtotal:	$46,949,319.23	$3,563,954.70	($7,285,212.50)	$0.00	$728,879.03	$0.00	($26,545.62)	$43,930,394.84
Fossil Hydro								
BOEING SOLAR								
FH Boeing Solar Project 341	$30,066.67	$6,374.52	$0.00	$0.00	$0.00	$0.00	$0.00	$36,441.19
FH Boeing Solar Project 344	$1,830,591.64	$397,940.16	$0.00	$0.00	$0.00	$0.00	$0.00	$2,228,531.80
FH Boeing Solar Project 345	$572,646.90	$124,795.80	$0.00	$0.00	$0.00	$0.00	$0.00	$697,442.70

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
BOEING SOLAR								
FH Boeing Solar Project 346	$4,805.95	$935.04	$0.00	$0.00	$0.00	$0.00	$0.00	$5,740.99
Depr Summ2 Subtotal:	$2,438,111.16	$530,045.52	$0.00	$0.00	$0.00	$0.00	$0.00	$2,968,156.68
BURTON GT								
FH Burton GT 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Burton GT 341 - Structures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Burton GT 342 - Fuel Holders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Burton GT 343 - Prime Movers	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Burton GT 344 - Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Burton GT 345 - Acc Elect Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Burton GT 346 - Misc Elect Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
BUSHY PARK GT								
FH Bushy Park GT 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Bushy Park GT 341 - Structures	$213,386.69	$12,803.42	$0.00	$0.00	$0.00	$0.00	$0.00	$226,190.11
FH Bushy Park GT 342 - Fuel Holders	$137,072.49	$1,495.44	$0.00	$0.00	$0.00	$0.00	$0.00	$138,567.93
FH Bushy Park GT 343 - Prime Movers	$5,172,925.91	$119,825.67	($14,529.81)	($7,901.11)	$0.00	$0.00	$0.00	$5,270,320.66
FH Bushy Park GT 344 - Generators	$62,791.20	$590.40	$0.00	$0.00	$0.00	$0.00	$0.00	$63,381.60
FH Bushy Park GT 345 - Acc Elect Eq	$135,877.29	$6,662.64	$0.00	$0.00	$0.00	$0.00	$0.00	$142,539.93
FH Bushy Park GT 346 - Misc Plt Eq	$65,932.00	$1,819.32	$0.00	$0.00	$0.00	$0.00	$0.00	$67,751.32
Depr Summ2 Subtotal:	$5,787,985.58	$143,196.89	($14,529.81)	($7,901.11)	$0.00	$0.00	$0.00	$5,908,751.55
CANADYS								
FH Canadys 310 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Canadys 311 - Structures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Canadys 312 - Boiler Plant Eq	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Canadys 314 - Turbogenerator Un	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Canadys 315 - Accessory Elect Eq	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Canadys 316 - Misc Plant Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
COIT GT								
FH Coit GT 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Coit GT 341 - Structures	$150,704.81	$3,273.72	$0.00	$0.00	$0.00	$0.00	$0.00	$153,978.53
FH Coit GT 342 - Fuel Holders	$512,860.39	$9,890.88	$0.00	$0.00	$0.00	$0.00	$0.00	$522,751.27
FH Coit GT 343 - Prime Movers	$943,444.22	$28,529.69	$0.00	$0.00	$0.00	($49.78)	$0.00	$971,924.13
FH Coit GT 344 - Generators	$3,610,905.77	$22,401.76	$0.00	$0.00	$0.00	$49.78	$0.00	$3,633,357.31
FH Coit GT 345 - Acc Elect Equip	$416,092.47	$21,925.30	($10,104.67)	($20,395.48)	$0.00	$0.00	$0.00	$407,517.62
FH Coit GT 346 - Misc Plt Equip	$121,091.62	$2,695.68	$0.00	$0.00	$0.00	$0.00	$0.00	$123,787.30
Depr Summ2 Subtotal:	$5,755,099.28	$88,717.03	($10,104.67)	($20,395.48)	$0.00	$0.00	$0.00	$5,813,316.16
COLUMBIA								
FH Columbia Hydro 3301 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Columbia Hydro 331 - Structures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Columbia Hydro 332 - Reservoirs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Columbia Hydro 333 - Waterwheel	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Columbia Hydro 334 - Acc Elec Eq	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Columbia Hydro 335 - Misc Pwr Pl	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Columbia Hydro 336 - Roads, RR	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
COPE								
FH Cope 310 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Cope 311 - Structures	$37,908,743.48	$1,322,612.32	($1,092,650.00)	($2,094,507.41)	$0.00	$0.00	$0.00	$36,044,198.39
FH Cope 312 - Boiler Plant Equip	$147,120,606.46	$7,833,581.90	($2,062,887.06)	($1,161,206.65)	$0.00	$0.00	$0.00	$151,730,094.65
FH Cope 312-Boiler Pl Equip-SCR	$13,723,240.17	$2,062,400.60	$0.00	$0.00	$0.00	$0.00	$0.00	$15,785,640.77
FH Cope 314 - Turbogenerator Units	$51,117,046.99	$1,744,013.77	($78,115.40)	($4,413.03)	$0.00	$0.00	$0.00	$52,778,532.33
FH Cope 315 - Accessory Elect Eq	$13,329,650.00	$360,481.49	($64,941.56)	($5,397.04)	$0.00	$0.00	$0.00	$13,619,792.89
FH Cope 316 - Misc Power Plant Eq	$3,707,726.85	$234,096.34	($26,104.27)	($1,863.62)	$0.00	$0.00	$0.00	$3,913,855.30
FH Cope 316 - Misc Pwr Plt Eq(SCR)	$173,333.92	$12,862.56	$0.00	$0.00	$0.00	$0.00	$0.00	$186,196.48
Depr Summ2 Subtotal:	$267,080,347.87	$13,570,048.98	($3,324,698.29)	($3,267,387.75)	$0.00	$0.00	$0.00	$274,058,310.81
Electric FH								
FH 390.8 Structures-Leasehold Imp	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 390.9 Struct Wareh-Lhold Imp	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

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Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
Electric FH								
FH 3901 Structures & Improvements	$4,971.65	$1,819.97	($961.23)	($13,216.58)	$0.00	$881.12	$0.00	($6,505.07)
FH 3902 Structures & Improvements	$6,164.07	$339.72	$0.00	$0.00	$0.00	$0.00	$0.00	$6,503.79
FH 3911 Office Furniture & Equip	$34,072.18	$2,966.54	($1,233.04)	$0.00	$0.00	$0.00	$0.00	$35,805.68
FH 3912 EDP Equipment	$199.02	$659.16	$0.00	$0.00	$0.00	$0.00	$0.00	$858.18
FH 3913 Data Handling Equipment	$10,399.80	$2,855.40	$0.00	$0.00	$0.00	$0.00	$0.00	$13,255.20
FH 3914 EDP (SCPSC ORDER) Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3919 OFE - LEASEHOLD	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 393 Stores Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3941 Tools, Shop & Gar Eq - HT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3942 Tools, Shop & Gar Eq - LN	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3943 Tools, Shop & Gar Eq - SH	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3944 Tools, Shop & Gar Eq - GA	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3951 Laboratory Equip - Meter	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3952 Laboratory Equip - Other	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 3953 Laboratory Equip - Field	$113,501.03	$21,802.26	($32,793.10)	$0.00	$0.00	$0.00	$0.00	$102,510.19
FH 397 Communication Equipment	$1,106,736.57	$49,564.34	($211,235.30)	$0.00	$0.00	$0.00	$0.00	$945,065.61
FH 3975 Communication Equip - CIPV	$0.00	$9,424.99	$0.00	$0.00	$0.00	$0.00	$0.00	$9,424.99
FH 398 Miscellaneous Equipment	$481,964.33	$36,644.72	($1,376.97)	$0.00	$0.00	$0.00	$0.00	$517,232.08
Depr Summ2 Subtotal:	$1,758,008.65	$126,077.10	($247,599.64)	($13,216.58)	$0.00	$881.12	$0.00	$1,624,150.65
FABER PLACE GT								
FH Faber Place GT 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Faber Place GT 341 - Structures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Faber Place GT 342- Fuel Holders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Faber Place GT 343 -Prime Movers	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Faber Place GT 344 - Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Faber Place GT 345 - Acc Elt Eq	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Faber Place GT 346 - Misc Plt Eq	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FAIRFIELD								
FH Fairfield Hydro 3301 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Fairfield Hydro 331 - Structures	$17,477,696.17	$312,179.05	($1,355.51)	($1,989.83)	$0.00	$0.00	$0.00	$17,786,529.88

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Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
FAIRFIELD								
FH Fairfield Hydro 332 - Reservoirs	$34,880,237.33	$605,124.11	$0.00	$0.00	$0.00	$0.00	$0.00	$35,485,361.44
FH Fairfield Hydro 333 - Waterwheel	$20,558,052.16	$917,765.06	($15,667.97)	($904.41)	$0.00	$0.00	$0.00	$21,459,244.84
FH Fairfield Hydro 334 - Acc Elec E	($1,913,807.39)	$396,504.10	($100,361.39)	($12,513.62)	$0.00	$1,854,195.68	$0.00	$224,017.38
FH Fairfield Hydro 335 - Misc Pwr P	$1,966,821.02	$110,742.60	($38,637.66)	($62.57)	$0.00	($1,854,195.68)	$0.00	$184,667.71
FH Fairfield Hydro 336 - Roads, RR	$786,182.65	$16,604.16	$0.00	$0.00	$0.00	$0.00	$0.00	$802,786.81
Depr Summ2 Subtotal:	$73,755,181.94	$2,358,919.08	($156,022.53)	($15,470.43)	$0.00	$0.00	$0.00	$75,942,608.06
Franchise/License								
FH Columbia Hydro 302 Franchise	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Fairfield Hydro 302 Franchise	$48,579.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$48,579.04
FH Neal Shoal Hydro 302 Franchise	$747,898.33	$37,679.04	$0.00	$0.00	$0.00	$0.00	$0.00	$785,577.37
FH Saluda Hydro 302 Franchise	$793,256.76	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$793,256.76
FH Stevens Cr Hydro 302 Franchise	$1,510,055.84	$75,537.72	$0.00	$0.00	$0.00	$0.00	$0.00	$1,585,593.56
Depr Summ2 Subtotal:	$3,099,789.97	$113,216.76	$0.00	$0.00	$0.00	$0.00	$0.00	$3,213,006.73
Generation plants								
FH 353 Station Equipment	$1,747,110.79	$99,804.09	$0.00	$0.00	$0.00	$0.00	$0.00	$1,846,914.88
Depr Summ2 Subtotal:	$1,747,110.79	$99,804.09	$0.00	$0.00	$0.00	$0.00	$0.00	$1,846,914.88
HAGOOD GT								
FH Hagood GT 3401 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Hagood GT 341 - Structures	$2,458,758.90	$44,446.59	$0.00	$0.00	$0.00	$0.00	$0.00	$2,503,205.49
FH Hagood GT 342 - F/Holders	$778,234.72	$7,250.30	$0.00	$0.00	$0.00	$0.00	$0.00	$785,485.02
FH Hagood GT 343 - Prime Movers	$21,737,121.27	$546,813.99	($56,544.20)	($18,681.08)	$0.00	$0.00	$0.00	$22,208,709.98
FH Hagood GT 344 - Generators	$4,849,837.90	$65,599.26	($3,892.90)	($1,339.63)	$0.00	$0.00	$0.00	$4,910,204.63
FH Hagood GT 345 - Acc Elec Eq	$1,921,297.63	$43,905.59	$0.00	$0.00	$0.00	$0.00	$0.00	$1,965,203.22
FH Hagood GT 346 - Misc Pwr Pl	$90,104.41	$10,454.79	($2,371.26)	$0.00	$0.00	$0.00	$0.00	$98,187.94
Depr Summ2 Subtotal:	$31,835,354.83	$718,470.52	($62,808.36)	($20,020.71)	$0.00	$0.00	$0.00	$32,470,996.28
HAGOOD ICT U5								
FH Hagood ICT U5 341 - Structures	$56,686.31	$8,129.76	$0.00	$0.00	$0.00	$0.00	$0.00	$64,816.07
FH Hagood ICT U5 342 - F/Holders	$60,535.90	$8,853.60	$0.00	$0.00	$0.00	$0.00	$0.00	$69,389.50
FH Hagood ICT U5 343 - Prime Movers	$3,175,554.92	$103,402.34	($22,803.08)	($821.24)	$0.00	$0.00	$0.00	$3,255,332.94

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
HAGOOD ICT U5								
FH Hagood ICT U5 344 - Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Hagood ICT U5 345 - Acc Elec Eq	$329,434.07	$61,455.97	$0.00	$0.00	$0.00	$0.00	$0.00	$390,890.04
FH Hagood ICT U5 346 - Misc Pwr Pl	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$3,622,211.20	$181,841.67	($22,803.08)	($821.24)	$0.00	$0.00	$0.00	$3,780,428.55
HAGOOD ICT U6								
FH Hagood ICT U6 341 - Structures	$106,529.93	$15,848.76	$0.00	$0.00	$0.00	$0.00	$0.00	$122,378.69
FH Hagood ICT U6 342 - F/Holders	$75,281.59	$11,010.12	$0.00	$0.00	$0.00	$0.00	$0.00	$86,291.71
FH Hagood ICT U6 343 - Prime Movers	$2,852,893.29	$135,163.43	($436,501.35)	($151,247.70)	$0.00	$0.00	$0.00	$2,400,307.67
FH Hagood ICT U6 344 - Generators	$95,422.63	$76.92	$0.00	$0.00	$0.00	$0.00	$0.00	$95,499.55
FH Hagood ICT U6 345 - Acc Elec Eq	$531,873.84	$90,694.07	$0.00	$0.00	$0.00	$0.00	$0.00	$622,567.91
FH Hagood ICT U6 346 - Misc Pwr Pl	$4,021.72	$1,626.96	$0.00	$0.00	$0.00	$0.00	$0.00	$5,648.68
Depr Summ2 Subtotal:	$3,666,023.00	$254,420.26	($436,501.35)	($151,247.70)	$0.00	$0.00	$0.00	$3,332,694.21
HARDEEVILLE GT								
FH Hardeeville GT 3401 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Hardeeville GT 341 - Structures	$47,462.14	$7,545.60	$0.00	$0.00	$0.00	$0.00	$0.00	$55,007.74
FH Hardeeville GT 342 - F/Holders	$533,534.39	$47,076.24	$0.00	$0.00	$0.00	$0.00	$0.00	$580,610.63
FH Hardeeville GT 343 - Prime Mover	$769,499.20	$66,219.84	$0.00	$0.00	$0.00	$0.00	$0.00	$835,719.04
FH Hardeeville GT 344 - Generators	$1,555,645.14	$290,979.96	$0.00	$0.00	$0.00	$0.00	$0.00	$1,846,625.10
FH Hardeeville GT 345 - Acc Elec Eq	$219,995.11	$56,652.24	$0.00	$0.00	$0.00	$0.00	$0.00	$276,647.35
FH Hardeeville GT 346 - Misc Pwr Pl	$39,296.11	$20,597.40	$0.00	$0.00	$0.00	$0.00	$0.00	$59,893.51
Depr Summ2 Subtotal:	$3,165,432.09	$489,071.28	$0.00	$0.00	$0.00	$0.00	$0.00	$3,654,503.37
JASPER STATION								
FH Jasper 312 - Boiler Plant Eq	$1,379.60	$11,994.79	$0.00	$0.00	$0.00	$0.00	$0.00	$13,374.39
FH Jasper 314 - Turbogenerator Un	$22,773,437.04	$2,629,135.76	($570,207.78)	($63,284.36)	$0.00	($18,926.58)	$0.00	$24,750,154.08
FH Jasper 315 - Accessory Electric	$1,383,349.30	$117,271.62	($9,639.84)	($783.71)	$0.00	$0.00	$0.00	$1,490,197.37
FH Jasper 316 - Misc Plant Equip	$49,017.87	$11,499.30	$0.00	$0.00	$0.00	$0.00	$0.00	$60,517.17
FH Jasper 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Jasper Station 341 - Structures	$8,844,007.30	$608,911.43	($11,750.84)	$0.00	$0.00	$0.00	$0.00	$9,441,167.89
FH Jasper Station 342 - Fuel Holder	$170.39	$249.00	$0.00	$0.00	$0.00	$0.00	$0.00	$419.39
FH Jasper Station 343-Prime Movers	$145,776,571.68	$10,786,131.90	($512,000.60)	($79,098.37)	$0.00	$0.00	$0.00	$155,971,604.61

Note: This report is filtered.

Monthly Depreciation Reserve Activity

SCANA

Starting Month: 10/2016
Ending Month: 09/2017

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
JASPER STATION								
FH Jasper Station 344-Generators	$10,377,509.12	$569,604.33	($1,404.25)	($175.84)	$0.00	$0.00	$0.00	$10,945,533.36
FH Jasper Station 345- Acc Elec Eq	$10,922,857.66	$772,347.17	$0.00	$0.00	$0.00	$0.00	$0.00	$11,695,204.83
FH Jasper Station 346-Misc Equip.	$30,252.64	$21,993.43	$0.00	$0.00	$0.00	$0.00	$0.00	$52,246.07
Depr Summ2 Subtotal:	$200,158,552.60	$15,529,138.73	($1,105,003.31)	($143,342.28)	$0.00	($18,926.58)	$0.00	$214,420,419.16
MCMEEKIN								
FH Central Lab 310 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Central Lab 311 - Structures	$2,437,676.34	$150,006.28	$0.00	$0.00	$0.00	$0.00	$0.00	$2,587,682.62
FH Central Lab 315 - Access Elec Eq	$51,333.12	$1,468.92	$0.00	$0.00	$0.00	$0.00	$0.00	$52,802.04
FH Central Lab 316 - Misc Plant Eq	$739,980.26	$169,779.19	$0.00	$0.00	$0.00	$0.00	$0.00	$909,759.45
FH McMeekin 310 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH McMeekin 311 - Structures	$12,022,427.15	$959,373.21	($60,034.77)	($4,610.22)	$0.00	$0.00	$0.00	$12,917,155.37
FH McMeekin 312 - Boiler Plant Eq	$54,091,021.54	$7,399,265.82	($96,221.94)	($316,110.45)	$0.00	$0.00	$0.00	$61,077,954.97
FH McMeekin 314 - Turbogenerator Ur	$23,137,449.05	$2,250,833.95	($8,957.00)	($1,816.69)	$0.00	$0.00	$0.00	$25,377,509.31
FH McMeekin 315 - Accessory Elec Eq	$6,884,720.08	$533,225.34	$0.00	$0.00	$0.00	$0.00	$0.00	$7,417,945.42
FH McMeekin 316 - Misc Plant Equip	$2,194,109.02	$210,816.77	($43,154.74)	($11,977.83)	$0.00	$0.00	$0.00	$2,349,793.22
Depr Summ2 Subtotal:	$101,558,716.56	$11,674,769.48	($208,368.45)	($334,515.19)	$0.00	$0.00	$0.00	$112,690,602.40
NEAL SHOALS								
FH Neal Shoal Hydro 3301 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Neal Shoal Hydro 331 - Structure	$504,626.66	$9,058.46	($3,347.65)	$0.00	$0.00	$0.00	$0.00	$510,337.47
FH Neal Shoal Hydro 332 - Reservoir	$859,416.61	$85,198.99	($22,067.29)	($6,228.08)	$0.00	$0.00	$0.00	$916,320.23
FH Neal Shoal Hydro 333 - Waterwhee	$1,435,025.60	$52,902.72	$0.00	$0.00	$0.00	$0.00	$0.00	$1,487,928.32
FH Neal Shoal Hydro 334 - Acc Elec	$227,429.39	$7,484.83	($3,068.04)	($6,244.35)	$0.00	$0.00	$0.00	$225,601.83
FH Neal Shoal Hydro 335 - Misc Pwr	$138,419.31	$5,078.79	($15,457.77)	($559.97)	$0.00	$0.00	$0.00	$127,480.36
FH Neal Shoal Hydro 336 - Roads, RR	$2,071.35	$16.92	$0.00	$0.00	$0.00	$0.00	$0.00	$2,088.27
Depr Summ2 Subtotal:	$3,166,988.92	$159,740.71	($43,940.75)	($13,032.40)	$0.00	$0.00	$0.00	$3,269,756.48
Non-depreciable								
FH Non-depreciable	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH None	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
None								
FH 340.1 Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH 389 Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PARR								
FH Parr Hydro 3301 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Parr Hydro 331 - Structures	$299,916.96	$40,419.35	($2,130.34)	($436.72)	$0.00	$0.00	$0.00	$337,769.25
FH Parr Hydro 332 - Reservoirs	$2,205,879.27	$67,260.51	($228,114.67)	($37,603.14)	$0.00	$0.00	$0.00	$2,007,421.97
FH Parr Hydro 333 - Waterwheels	$598,822.08	$54,719.88	$0.00	$0.00	$0.00	$0.00	$0.00	$653,541.96
FH Parr Hydro 334 - Acc Elec Equip	$849,741.49	$36,854.28	$0.00	$0.00	$0.00	$0.00	$0.00	$886,595.77
FH Parr Hydro 335 - Misc Power Plnt	$152,856.47	$8,819.41	($5,580.96)	$0.00	$0.00	$0.00	$0.00	$156,094.92
FH Parr Hydro 336 - Roads, Railroad	$81,375.41	$968.76	$0.00	$0.00	$0.00	$0.00	$0.00	$82,344.17
Depr Summ2 Subtotal:	$4,188,591.68	$209,042.19	($235,825.97)	($38,039.86)	$0.00	$0.00	$0.00	$4,123,768.04
PARR GT								
FH Parr GT 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Parr GT 341 - Structures	$563,898.91	$29,410.30	($1,244.85)	($128.69)	$0.00	$0.00	$0.00	$591,935.67
FH Parr GT 342 - Fuel Holders	$477,466.90	$14,748.12	$0.00	$0.00	$0.00	$0.00	$0.00	$492,215.02
FH Parr GT 343 - Prime Movers	$1,025,482.55	$320,308.62	$0.00	$0.00	$0.00	$0.00	$0.00	$1,345,791.17
FH Parr GT 344 - Generators	$2,334,484.51	$37,155.60	($2,030.63)	($125,456.16)	$0.00	$0.00	$0.00	$2,244,153.32
FH Parr GT 345 - Acc Elect Equip	$702,523.99	$39,827.20	($10,674.51)	($8,711.59)	$0.00	$0.00	$0.00	$722,965.09
FH Parr GT 345.5-Acc Elect Eq CIPV5	$27,541.62	$66,891.96	$0.00	$0.00	$0.00	$0.00	$0.00	$94,433.58
FH Parr GT 346 - Misc Plt Equip	$111,505.69	$7,378.08	$0.00	$0.00	$0.00	$0.00	$0.00	$118,883.77
Depr Summ2 Subtotal:	$5,242,904.17	$515,719.88	($13,949.99)	($134,296.44)	$0.00	$0.00	$0.00	$5,610,377.62
SALUDA								
FH Saluda Hydro 3301 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Saluda Hydro 331 - Structures	$2,722,206.04	$99,604.38	($2,197.77)	($8,228.56)	$0.00	$0.00	$0.00	$2,811,384.09
FH Saluda Hydro 332 - Reservoirs	$14,590,627.57	$189,920.55	($4,017.62)	($1,160.36)	$0.00	$0.00	$0.00	$14,775,370.14
FH Saluda Hydro 3325- Res(Synfuel)	$262,753,982.49	$1,131,676.08	$0.00	$0.00	$0.00	$0.00	$0.00	$263,885,658.57
FH Saluda Hydro 333 - Waterwheels	$5,198,536.44	$132,650.03	($8,661.48)	($68,624.05)	$0.00	$0.00	$0.00	$5,253,900.94
FH Saluda Hydro 334 - Acc Elec Eq	$771,241.86	$41,743.27	($3,780.27)	($73,549.09)	$0.00	$0.00	$0.00	$735,655.77
FH Saluda Hydro 335 - Misc Pwr Pl	$436,855.19	$34,919.95	($57,358.51)	$0.00	$0.00	$0.00	$0.00	$414,416.63

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Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
SALUDA								
FH Saluda Hydro 336 - Roads, RR	$145,826.37	$2,078.40	$0.00	$0.00	$0.00	$0.00	$0.00	$147,904.77
Depr Summ2 Subtotal:	$286,619,275.96	$1,632,592.66	($76,015.65)	($151,562.06)	$0.00	$0.00	$0.00	$288,024,290.91
Software								
FH 303 Software	$4,961,507.94	$848,177.22	($284,139.91)	$0.00	$0.00	$18,926.58	$0.00	$5,544,471.83
FH 303 Software, Leasehold	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$4,961,507.94	$848,177.22	($284,139.91)	$0.00	$0.00	$18,926.58	$0.00	$5,544,471.83
SOLAR FARM								
FH Solar Farm 340	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Solar Farm 341	$0.00	$86.67	$0.00	$0.00	$0.00	$0.00	$0.00	$86.67
FH Solar Farm 346	$0.00	$8.83	$0.00	$0.00	$0.00	$0.00	$0.00	$8.83
Depr Summ2 Subtotal:	$0.00	$95.50	$0.00	$0.00	$0.00	$0.00	$0.00	$95.50
Step up Transformers								
FH Burton GT 353 StepUp Xfmr	$13,349.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$13,349.06
FH Bushy Park GT 353 StepUp Xfmr	$151,551.92	$2,963.16	$0.00	$0.00	$0.00	$0.00	$0.00	$154,515.08
FH Canadys 353 StepUp Xfmr	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Coit GT 353 StepUp Xfmr	$139,428.28	$1,228.80	$0.00	$0.00	$0.00	$0.00	$0.00	$140,657.08
FH Columbia Hydro 353 StepUp Xfmr	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Cope 353 StepUp Xfmr	$2,689,408.79	$131,236.56	$0.00	$0.00	$0.00	$0.00	$0.00	$2,820,645.35
FH Faber Place GT 353 StepUp Xfmr	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Fairfield Hydro 353 StepUp Xfmr	$2,511,795.56	$142,422.60	$0.00	$0.00	$0.00	$0.00	$0.00	$2,654,218.16
FH Hagood 353 GT StepUp Xfmr	$1,490,098.96	$34,038.24	$0.00	$0.00	$0.00	$0.00	$0.00	$1,524,137.20
FH Hardeeville GT 353 StepUp Xfmr	$109,327.66	$1,890.72	$0.00	$0.00	$0.00	$0.00	$0.00	$111,218.38
FH Jasper 353 StepUp Xfmr	$5,607,518.38	$422,122.80	$0.00	$0.00	$0.00	$0.00	$0.00	$6,029,641.18
FH McMeekin 353 StepUp Xfmr	$713,824.35	$19,328.28	$0.00	$0.00	$0.00	$0.00	$0.00	$733,152.63
FH Parr Hydro 353 StepUp Xfmr	$301,954.37	$10,055.28	$0.00	$0.00	$0.00	$0.00	$0.00	$312,009.65
FH Saluda Hydro 353 StepUp Xfmr	$494,569.84	$8,987.40	$0.00	$0.00	$0.00	$0.00	$0.00	$503,557.24
FH Stevens Cr Hydro 353 StepUp Xfm	$252,146.96	$7,750.08	$0.00	$0.00	$0.00	$0.00	$0.00	$259,897.04
FH Stevens Creek 353 StepUp Xfmr	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urquhart 353 StepUp Xfmr	$1,361,936.50	$25,677.12	$0.00	$0.00	$0.00	$0.00	$0.00	$1,387,613.62
FH Urquhart GT 353 StepUp Xfmr	$587,766.39	$28,260.36	$0.00	$0.00	$0.00	$0.00	$0.00	$616,026.75

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
Step up Transformers								
FH Wateree 353 StepUp Xfmr	$1,097,305.44	$234,534.72	$0.00	$0.00	$0.00	$0.00	$0.00	$1,331,840.16
FH Westvaco Generator 353 Step-Up	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Williams 353 StepUp Xfmr	$915,131.15	$39,975.60	$0.00	$0.00	$0.00	$0.00	$0.00	$955,106.75
FH Williams 353 StepUp Xfmr-GSU	$5,521,390.92	$184,549.80	$0.00	$0.00	$0.00	$0.00	$0.00	$5,705,940.72
Depr Summ2 Subtotal:	$23,958,504.53	$1,295,021.52	$0.00	$0.00	$0.00	$0.00	$0.00	$25,253,526.05
STEVENS CREEK								
FH Stevens Cr Hydro 3301 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Stevens Cr Hydro 331 - Structure	$1,718,164.18	$26,617.40	($11,765.57)	($1,058.00)	$0.00	$0.00	$0.00	$1,731,958.01
FH Stevens Cr Hydro 332 - Reservoir	$4,059,066.37	$55,942.80	$0.00	($943.41)	$0.00	$0.00	$0.00	$4,114,065.76
FH Stevens Cr Hydro 333 - Waterwhee	$1,540,870.24	$27,459.77	$0.00	$0.00	$0.00	$0.00	$0.00	$1,568,330.01
FH Stevens Cr Hydro 334 - Acc Elec	$522,869.45	$12,188.04	$0.00	$0.00	$0.00	$0.00	$0.00	$535,057.49
FH Stevens Cr Hydro 335 - Misc Pwr	$561,309.19	$12,011.35	($43,215.70)	($855.92)	$0.00	$0.00	$0.00	$529,248.92
FH Stevens Cr Hydro 336 - Roads, RR	$56,123.28	$1,339.68	$0.00	$0.00	$0.00	$0.00	$0.00	$57,462.96
Depr Summ2 Subtotal:	$8,458,402.71	$135,559.04	($54,981.27)	($2,857.33)	$0.00	$0.00	$0.00	$8,536,123.15
URQUHART								
FH Urquhart 310 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urquhart 311 - Structures	$13,477,309.32	$679,381.46	($104,773.74)	($433,924.82)	$40,631.35	$0.00	$0.00	$13,658,623.57
FH Urquhart 312 - Boiler Plant Eq	$8,630,031.65	$2,180,426.31	($336,656.51)	($2,862,869.90)	$284,019.76	$0.00	$0.00	$7,894,951.31
FH Urquhart 314 - Turbogenerator Un	$32,000,479.80	$3,031,334.40	($2,850,132.50)	($2,437,451.62)	$0.00	$0.00	$0.00	$29,744,230.08
FH Urquhart 315 - Accessory Elec Eq	$5,161,976.05	$599,347.98	($88,531.69)	($556,018.29)	$8,556.79	$0.00	$0.00	$5,125,330.84
FH Urquhart 316 - Misc Plant Equip	$1,596,227.61	$327,779.74	($24,124.46)	($36,664.33)	$3,907.49	$0.00	$0.00	$1,867,126.05
Depr Summ2 Subtotal:	$60,866,024.43	$6,818,269.89	($3,404,218.90)	($6,326,928.96)	$337,115.39	$0.00	$0.00	$58,290,261.85
URQUHART GT								
FH Urq GT #3 341 - Structures & Imp	$103,616.69	$22,923.24	$0.00	$0.00	$0.00	$0.00	$0.00	$126,539.93
FH Urq GT #3 342 - Fuel Holders	$5,706.81	$294.84	$0.00	$0.00	$0.00	$0.00	$0.00	$6,001.65
FH Urq GT #3 343 - Prime Movers	$50,808.26	$17,647.71	$0.00	$0.00	$0.00	$0.00	$0.00	$68,455.97
FH Urq GT #3 344 - Generators	$1,196,137.88	$66,362.77	($287,298.02)	($120,905.63)	$0.00	$0.00	$0.00	$854,297.00
FH Urq GT #3 345 - Accessory Equip	$21,920.64	$3,428.76	$0.00	$0.00	$0.00	$0.00	$0.00	$25,349.40
FH Urquhart GT 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urquhart GT 341 - Structures	$308,376.33	$38,919.60	$0.00	$0.00	$0.00	$0.00	$0.00	$347,295.93

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
URQUHART GT								
FH Urquhart GT 342 - Fuel Holders	$98,606.13	$5,189.40	$0.00	$0.00	$0.00	$0.00	$0.00	$103,795.53
FH Urquhart GT 343 - Prime Movers	$218,474.14	$25,039.46	$0.00	$0.00	$0.00	$0.00	$0.00	$243,513.60
FH Urquhart GT 344 - Generators	$2,179,640.39	$74,844.90	($21,022.61)	($4,528.15)	$0.00	$0.00	$0.00	$2,228,934.53
FH Urquhart GT 345 - Acc Elect Eq	$17,199.52	$8,460.00	$0.00	$0.00	$0.00	$0.00	$0.00	$25,659.52
FH Urquhart GT 346 - Misc Plt Equip	$14,510.55	$3,363.15	($11,274.29)	($196.04)	$0.00	$0.00	$0.00	$6,403.37
Depr Summ2 Subtotal:	$4,214,997.34	$266,473.83	($319,594.92)	($125,629.82)	$0.00	$0.00	$0.00	$4,036,246.43
URQUHART GT #4								
FH Urq GT #4 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urq GT #4 341 - Structures	$255,066.06	$2,623.32	$0.00	$0.00	$0.00	$0.00	$0.00	$257,689.38
FH Urq GT #4 342 - Fuel Holders	$938,407.41	$1,989.34	($763,929.02)	($36,461.14)	$0.00	$0.00	$0.00	$140,006.59
FH Urq GT #4 343 - Prime Movers	$459,862.44	$120,021.16	($45,096.73)	($1,248.77)	$41,850.00	$0.00	$0.00	$575,388.10
FH Urq GT #4 344 - Generators	$11,767,471.89	$271,065.14	($166,849.85)	($76,747.08)	$0.00	$0.00	$0.00	$11,794,940.10
FH Urq GT #4 345 - Acc Elect Equip	$187,888.80	$10,548.36	$0.00	$0.00	$0.00	$68.89	$0.00	$198,506.05
FH Urq GT #4 346 - Misc Plt Equip	($268.69)	$1,212.52	$0.00	$0.00	$0.00	($68.89)	$0.00	$874.94
Depr Summ2 Subtotal:	$13,608,427.91	$407,459.84	($975,875.60)	($114,456.99)	$41,850.00	$0.00	$0.00	$12,967,405.16
URQUHART GT #5 & #6								
FH Urq GT #5 & #6 340 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urq GT #5 & #6 3402 - Ld Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urq GT #5 & #6 3405 - Land-SCPC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urq GT #5 & #6 341 - Structures	$2,174,244.03	$94,028.80	$0.00	$0.00	$0.00	$0.00	$0.00	$2,268,272.83
FH Urq GT #5 & #6 342 - Fuel Holder	$2,146,586.86	$63,521.64	$0.00	$0.00	$0.00	$0.00	$0.00	$2,210,108.50
FH Urq GT #5 & #6 3425 - Fuel Hold	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Urq GT #5 & #6 343-Prime Movers	$115,750,174.72	$7,865,890.14	($158,198.93)	($69,108.11)	$0.00	$0.00	$0.00	$123,388,757.82
FH Urq GT #5 & #6 344-Generators	$4,383,720.25	$239,561.16	$0.00	$0.00	$0.00	$0.00	$0.00	$4,623,281.41
FH Urq GT #5 & #6 345- Acc Elec Eq	$6,478,264.66	$381,522.48	($2,871.20)	($69.45)	$0.00	$0.00	$0.00	$6,856,846.49
FH Urq GT #5 & #6 346- Misc Equip	$26,647.02	$3,739.68	$0.00	$0.00	$0.00	$0.00	$0.00	$30,386.70
Depr Summ2 Subtotal:	$130,959,637.54	$8,648,263.90	($161,070.13)	($69,177.56)	$0.00	$0.00	$0.00	$139,377,653.75
WATEREE								
FH Wateree 310 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FH Wateree 311 - Structures	$35,860,452.02	$1,839,788.93	($159,984.67)	($11,956.89)	$0.00	$0.00	$0.00	$37,528,299.39

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Fossil Hydro								
WATEREE								
FH Wateree 311 -Strt-(SCR)Pnd&Ldfl	$7,562,083.41	$2,690,291.40	($16,694.36)	$0.00	$0.00	$0.00	$0.00	$10,235,680.45
FH Wateree 312 - Boiler Plant Eq	$159,054,983.00	$14,480,443.22	($2,475,824.52)	($1,392,603.54)	$0.00	$0.00	$0.00	$169,666,998.16
FH Wateree 312 - Boiler Plt Eq-SCR	$60,250,478.69	$8,508,045.41	($1,084,195.82)	($313,243.88)	$0.00	$0.00	$0.00	$67,361,084.40
FH Wateree 314 - Turbogenerator Un	$74,165,890.31	$4,356,053.79	($5,463,472.87)	($380.91)	$0.00	$0.00	$0.00	$73,058,090.32
FH Wateree 315 - Accessory Elect Eq	$12,468,048.08	$796,891.57	($15,969.82)	($12,272.00)	$0.00	$0.00	$0.00	$13,236,697.83
FH Wateree 316 - Misc Plant Equip	$2,567,793.68	$173,524.93	($482,097.74)	$0.00	$110,000.00	$0.00	$0.00	$2,369,220.87
Depr Summ2 Subtotal:	$351,929,729.19	$32,845,039.25	($9,698,239.80)	($1,730,457.22)	$110,000.00	$0.00	$0.00	$373,456,071.42
Company Subtotal:	$1,603,602,917.84	$99,659,192.82	$20,856,292.38)	$12,680,757.11)	$488,965.39	$881.12	$0.00	$1,670,214,907.68
Industrial								
Distribution IN								
IN 3601 Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
IN 3602 Land Rights and Easements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
IN 3608 Trans Easement Lease	$5,721.34	$1,809.12	$0.00	$0.00	$0.00	$0.00	$0.00	$7,530.46
IN 361 Structures & Improvements	$1,136,399.21	$82,186.20	($1,876.13)	$4,606.53	$5,887.31	$0.00	$0.00	$1,227,203.12
IN 361.8 Struct & Improv-Leasehold	$45,848.82	$7,519.20	$0.00	$0.00	$0.00	$0.00	$0.00	$53,368.02
IN 362 Station Equipment	$76,359,833.28	$7,502,847.95	($2,643,230.81)	($199,390.32)	$60,579.69	($92,071.50)	$0.00	$80,988,568.29
IN 362.5 Station Equipment CIPV5	$0.00	$10,576.12	$0.00	$0.00	$0.00	$0.00	$0.00	$10,576.12
IN 362.8 Station Equip- Leasehold	$1,225,637.02	$203,662.60	($31,097.09)	($950.00)	$0.00	$73,727.70	$0.00	$1,470,980.23
Depr Summ2 Subtotal:	$78,773,439.67	$7,808,601.19	($2,676,204.03)	($195,733.79)	$66,467.00	($18,343.80)	$0.00	$83,758,226.24
Electric IN								
IN 3901 Structures & Improvements	$4,608,869.34	$492,519.29	($20,936.20)	($245.00)	$0.00	$8,590.51	$0.00	$5,088,797.94
IN 39011 Str & Imp - Trans Op Ctr	$152,012.31	$8,266.95	$0.00	$0.00	$0.00	$0.00	$0.00	$160,279.26
IN 3902 Structures & Imp - WH	$544,591.76	$23,352.24	$0.00	$0.00	$0.00	$0.00	$0.00	$567,944.00
IN 3911 Office Furniture & Equip	$1,395,526.60	$216,858.00	($17,471.39)	$0.00	$0.00	$0.00	$0.00	$1,594,913.21
IN 3912 EDP Equipment	$428,242.64	$858,791.78	($241,496.45)	$0.00	$0.00	$0.00	$0.00	$1,045,537.97
IN 3913 Data Handling Equipment	$30,944.78	$4,705.80	$0.00	$0.00	$0.00	$0.00	$0.00	$35,650.58
IN 3914 EDP (SCPSC ORDER) Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
IN 393 Stores Equipment	$37,853.55	$1,313.88	$0.00	$0.00	$0.00	$0.00	$0.00	$39,167.43
IN 3941 Tools, Shop & Gar Eq - HT	$126,697.96	$12,157.02	($13,647.31)	$0.00	$0.00	$0.00	$0.00	$125,207.67

Note: This report is filtered.

Monthly Depreciation Reserve Activity

SCANA

Starting Month: 10/2016
Ending Month: 09/2017

Set of Books / Company / Depr Summary2 / Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Industrial								
Electric IN								
IN 3942 Tools, Shop & Gar Eq - LN	$665,521.57	$26,307.78	($115,863.73)	$0.00	$0.00	$0.00	$0.00	$575,965.62
IN 3943 Tools, Shop & Gar Eq - SH	$79,504.57	$9,082.87	($12,041.09)	$0.00	$0.00	$0.00	$0.00	$76,546.35
IN 3944 Tools, Shop & Gar Eq - GA	$16,872.61	$253.17	($4,775.28)	$0.00	$0.00	$0.00	$0.00	$12,350.50
IN 3951 Laboratory Equip - Meter	$633,811.03	$11,674.01	($161,353.16)	$0.00	$0.00	$0.00	$0.00	$484,131.88
IN 3952 Laboratory Equip - Other	$109,544.66	$12,679.14	($27,085.82)	$0.00	$0.00	$0.00	$0.00	$95,137.98
IN 3953 Laboratory Equip - Field	$1,492,711.61	$153,326.48	($123,141.57)	$0.00	$12,037.50	$0.00	$0.00	$1,534,934.02
IN 397 Communication Equipment	$3,090,430.48	$93,283.79	($236,477.83)	($212.65)	$0.00	$0.00	$0.00	$2,947,023.79
IN 3975 Communication Equip CIPV5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
IN 398 Miscellaneous Equipment	$941,964.70	$73,474.41	($42,111.82)	$0.00	$0.00	$0.00	$0.00	$973,327.29
Depr Summ2 Subtotal:	$14,355,100.17	$1,998,046.61	($1,016,401.65)	($457.65)	$12,037.50	$8,590.51	$0.00	$15,356,915.49
Generation plants								
IN Fairfield 353 Station Equip	$1,065,459.19	$5,008.10	($145,819.52)	($13,915.77)	$0.00	$0.00	$0.00	$910,732.00
IN Neal Shoal Hydro 354 - 356	$50,670.58	$171.58	$0.00	$0.00	$0.00	$0.00	$0.00	$50,842.16
IN Parr Hydro 352 - 353 Station Eq	$262,728.94	$11,862.60	$0.00	$0.00	$0.00	$0.00	$0.00	$274,591.54
IN Saluda Hydro 352 - 353	$4,222,416.38	$204,671.87	$0.00	$0.00	$0.00	$0.00	$0.00	$4,427,088.25
IN Stevens Cr Hydo 352 - 353	$1,752,208.87	$213,128.52	$0.00	$0.00	$0.00	$0.00	$0.00	$1,965,337.39
Depr Summ2 Subtotal:	$7,353,483.96	$434,842.67	($145,819.52)	($13,915.77)	$0.00	$0.00	$0.00	$7,628,591.34
None								
IN 389 Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Software								
IN 303 Software	$11,878,150.42	$1,218,099.22	($252,355.16)	$0.00	$0.00	($3,053.32)	$0.00	$12,840,841.16
IN 3035 Software, CIPV5	$116,262.31	$113,342.28	$0.00	$0.00	$0.00	$3,053.32	$0.00	$232,657.91
Depr Summ2 Subtotal:	$11,994,412.73	$1,331,441.50	($252,355.16)	$0.00	$0.00	$0.00	$0.00	$13,073,499.07
Transmission IN								
IN 3501 Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
IN 3502 Land Rights	$0.00	$0.00	($6,319.90)	$0.00	$0.00	$0.00	$6,319.90	$0.00
IN 3508 Trans Easement Lease	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
IN 352 Structs & Improv CIPV5	$13,346.56	$23,262.72	$0.00	$0.00	$0.00	$0.00	$0.00	$36,609.28

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Industrial								
Transmission IN								
IN 352 Structures & Improvements	$897,568.01	$61,389.02	($139.92)	($10.01)	$0.00	$0.00	$0.00	$958,807.10
IN 353 Station Equipment	$99,207,891.26	$6,427,722.44	($2,422,976.57)	($242,348.35)	$1,178.61	$21,715.90	$0.00	$102,993,183.29
IN 353 Station Equipment CIPV5	$232,587.05	$224,679.30	$0.00	($54.99)	$0.00	$0.00	$0.00	$457,211.36
IN 353.8 Station Equipment-Lease	$815,217.48	$88,349.04	$0.00	$0.00	$0.00	$0.00	$0.00	$903,566.52
IN 354 Towers & Fixtures	$4,650,811.16	$73,362.36	($1,862.40)	($2,686.58)	$0.00	$0.00	$0.00	$4,719,624.54
IN 355 Poles & Fixtures	$118,513,002.15	$13,010,023.18	($1,162,654.75)	($1,247,769.18)	$137,430.91	$61,370.50	$0.00	$129,311,402.81
IN 355.8 Poles & Fixtures- Lease	$309,939.58	$108,649.18	$0.00	$0.00	$61,895.46	$0.00	$0.00	$480,484.22
IN 356.2 Overhead Fiber Optic Shl	$938,996.36	$75,143.23	($35,850.40)	($70,456.33)	$0.00	$0.00	$0.00	$907,832.86
IN 356.8 Lease OH Conductors/Dev	$811,676.57	$163,467.24	$0.00	$0.00	$0.00	$0.00	$0.00	$975,143.81
IN 3561 Overhead Conductors/Device:	$70,066,696.83	$5,406,670.51	($1,112,897.94)	($1,454,891.97)	$29,717.31	($64,742.60)	$0.00	$72,870,552.14
IN 357 Underground Conduit	$3,733,079.44	$326,591.30	($1,475,128.08)	($152,266.64)	$56,413.03	($137,836.63)	$0.00	$2,350,852.42
IN 358 Underground Conductors/Dev	$8,869,355.80	$1,143,221.80	($4,635,700.77)	($733,900.11)	$271,901.57	$137,836.63	$0.00	$5,052,714.92
IN 359 Roads & Trails	$16,144.20	$1,040.16	$0.00	$0.00	$0.00	$0.00	$0.00	$17,184.36
Depr Summ2 Subtotal:	$309,076,312.45	$27,133,571.48	$10,853,530.73)	($3,904,384.16)	$558,536.89	$18,343.80	$6,319.90	$322,035,169.63
Company Subtotal:	$421,552,748.98	$38,706,503.45	$14,944,311.09)	($4,114,491.37)	$637,041.39	$8,590.51	$6,319.90	$441,852,401.77
Nuclear								
Electric NU								
NU 3901 Structures & Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 3911 Office Furniture & Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 3912 EDP Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 3913 Data Handling Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 393 Stores Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 3941 Tools, Shop & Garage Eq	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 3951 Laboratory Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 397 Communication Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU 398 Miscellaneous Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Electric NU- Vehicles								
NU 392 Vehicles, Electric	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Nuclear								
Electric NU- Vehicles								
NU 396 Power Oper Eq, Electric	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Franchise/License								
NU 302.2 Franchise	$2,795,890.21	$225,255.12	$0.00	$0.00	$0.00	$0.00	$0.00	$3,021,145.33
Depr Summ2 Subtotal:	$2,795,890.21	$225,255.12	$0.00	$0.00	$0.00	$0.00	$0.00	$3,021,145.33
Software								
NU 303 Software	$23,914,113.50	$1,480,125.51	$10,150,112.22)	$0.00	$0.00	$0.00	$0.00	$15,244,126.79
NU 303.3 Software-Misc Cyber Intang	$63,213.83	$2,535,326.18	$0.00	$0.00	$0.00	($2,498,857.46)	$0.00	$99,682.55
NU 3035 Software, CIPV5	$402.14	$689.40	$0.00	$0.00	$0.00	$0.00	$0.00	$1,091.54
Depr Summ2 Subtotal:	$23,977,729.47	$4,016,141.09	$10,150,112.22)	$0.00	$0.00	($2,498,857.46)	$0.00	$15,344,900.88
Step up Transformers								
NU VC Summer 353 Step Up Xfmr	$3,566,546.23	$497,606.16	$0.00	$0.00	$0.00	$0.00	$0.00	$4,064,152.39
Depr Summ2 Subtotal:	$3,566,546.23	$497,606.16	$0.00	$0.00	$0.00	$0.00	$0.00	$4,064,152.39
Transmission NU								
NU VC Summer 352 Structures	$250,828.02	$5,012.52	$0.00	$0.00	$0.00	$0.00	$0.00	$255,840.54
NU VC Summer 352.5 Structures CIPV	$1,532.83	$6,135.75	$0.00	$0.00	$0.00	$0.00	$0.00	$7,668.58
NU VC Summer 353 Station Equip	$6,461,090.00	$592,684.24	($43,834.02)	$0.00	$0.00	$0.00	$0.00	$7,009,940.22
NU VC Summer 353.5 Stat Eq CIPV5	$13,872.23	$48,282.26	$0.00	$0.00	$0.00	$0.00	$0.00	$62,154.49
Depr Summ2 Subtotal:	$6,727,323.08	$652,114.77	($43,834.02)	$0.00	$0.00	$0.00	$0.00	$7,335,603.83
V. C. SUMMER								
NU VC Summer 3201 - Land	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NU VC Summer 321 - Structures	$167,743,716.81	$3,281,524.55	($1,546,897.83)	($24,649.56)	$0.00	($882.02)	$0.00	$169,452,811.95
NU VC Summer 322 - Reactor Plant Eq	$271,679,635.22	$7,394,147.59	($7,042,148.74)	($598,571.74)	$96,564.80	$0.00	$0.00	$271,529,627.13
NU VC Summer 323 - Turbogenerator	$37,520,314.73	$2,564,156.20	($643,127.73)	($18,880.39)	$0.00	$0.00	$0.00	$39,422,462.81
NU VC Summer 324 - Acc Electric Eq	$70,554,291.15	$1,345,395.09	($275,510.90)	$0.00	$27,931.35	$882.02	$0.00	$71,652,988.71
NU VC Summer 325 - Misc Power Pl E	$39,109,585.70	$6,486,896.76	($1,221,715.16)	($238.33)	$2,308.75	$0.00	$0.00	$44,376,837.72

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Nuclear								
V. C. SUMMER								
NU VC Summer 325.1 Misc Pwr Cyber	$112,083.95	($1,911,340.40)	$0.00	$0.00	$0.00	$2,498,857.46	$0.00	$699,601.01
Depr Summ2 Subtotal:	$586,719,627.56	$19,160,779.79	$10,729,400.36)	($642,340.02)	$126,804.90	$2,498,857.46	$0.00	$597,134,329.33
Company Subtotal:	$623,787,116.55	$24,551,896.93	$20,923,346.60)	($642,340.02)	$126,804.90	$0.00	$0.00	$626,900,131.76
Retail Electric								
Distribution RE								
RE 301 Organization Expense	$14,988.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14,988.33
RE 302 Franchise, Other	$26,274.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$26,274.22
RE 3602 Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RE 3608 Trans Easement Lease	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RE 364 Poles, Towers & Fixtures	$130,199,655.04	$14,322,650.33	($3,473,385.55)	($2,439,593.13)	$132,827.99	($105.27)	$0.00	$138,742,049.41
RE 365 Overhead Conductors/Devices	$154,344,366.83	$8,344,729.38	($2,785,834.18)	($1,242,673.36)	$1,324,485.94	($5,785.92)	$0.00	$159,979,288.69
RE 366 Network	$7,040,741.14	$111,883.56	$0.00	$0.00	$0.00	$0.00	$0.00	$7,152,624.70
RE 366 Underground Conduit	$42,777,111.95	$2,099,861.67	($87,719.29)	($7,943.47)	$2,802.05	$0.00	$0.00	$44,784,112.91
RE 367 Network	$8,871,545.21	$195,878.16	$0.00	$0.00	$0.00	$0.00	$0.00	$9,067,423.37
RE 367 Undeground Conductors/Devi	$117,796,732.46	$8,454,694.48	($1,657,649.82)	($115,881.06)	$32,172.57	$5,870.21	$0.00	$124,515,938.84
RE 368 Line Transformers	$174,784,779.43	$9,561,744.36	($4,108,823.41)	($311,122.99)	$99.35	($98.21)	$0.00	$179,926,578.53
RE 3690 Services, Overhead	$62,911,781.96	$2,573,853.01	($181,377.76)	($202,538.21)	$0.00	$0.00	$0.00	$65,101,719.00
RE 3691 Services, Underground	$58,091,349.66	$2,682,322.28	($16,460.70)	($3,620.51)	$0.00	$0.00	$0.00	$60,753,590.73
RE 370 Meters	$12,187,487.36	$620,210.26	($171,225.92)	$230.56	$0.00	$82,797.72	$0.00	$12,719,499.98
RE 3703 Meters-AMR	$17,356,391.00	$6,778,791.28	($599,294.41)	$0.00	$0.00	($76,351.92)	$0.00	$23,459,535.95
RE 3704 Meters-AMI	$1,448,420.01	$1,415,523.48	($1,222,384.13)	$0.00	$0.00	($6,445.80)	$0.00	$1,635,113.56
RE 3705 Electric Meters DER	$19,715.68	$203,518.82	($846.56)	$0.00	$0.00	$0.00	$0.00	$222,387.94
RE 373 Street Lighting & Signal Sys	$102,572,674.25	$9,162,635.24	($2,661,522.04)	($1,006,720.10)	$38,400.73	$119.19	$0.00	$108,105,587.27
Depr Summ2 Subtotal:	$890,444,014.53	$66,528,296.31	$16,966,523.77)	($5,329,862.27)	$1,530,788.63	$0.00	$0.00	$936,206,713.43
Electric RE								
RE 3901 Structures & Improvements	$16,986,513.13	$1,092,033.06	($329,240.38)	($50,544.67)	$0.00	($121.40)	$0.00	$17,698,639.74
RE 39011 Struct & Imp- N. Cha E Ops	$2,465,128.24	$288,474.51	($4,040.08)	($419.31)	$0.00	$0.00	$0.00	$2,749,143.36
RE 3902 Structures & Imp - WH	$1,113,708.70	$210,474.52	($49,678.32)	($3,258.52)	$0.00	$0.00	$0.00	$1,271,246.38
RE 3908 Structures-Leasehold	$174,151.55	$769.44	$0.00	$0.00	$0.00	$0.00	$0.00	$174,920.99

Note: This report is filtered.

Monthly Depreciation Reserve Activity

SCANA

Starting Month: 10/2016
Ending Month: 09/2017

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Retail Electric								
Electric RE								
RE 3909 Struct-WH- Leasehold	$27,496.34	$3,097.80	$0.00	$0.00	$0.00	$0.00	$0.00	$30,594.14
RE 3911 Office Furniture & Equip	$1,534,878.12	$206,940.54	($36,200.20)	$0.00	$0.00	($8,590.51)	$0.00	$1,697,027.95
RE 3912 EDP Equipment	$126,731.06	$315,935.38	($252,678.41)	$0.00	$0.00	$0.00	$0.00	$189,988.03
RE 3913 Data Handling Equipment	$107,956.80	$12,047.36	($18,667.03)	$0.00	$0.00	$0.00	$0.00	$101,337.13
RE 3914 EDP (SCPSC ORDER) Equip	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RE 393 Stores Equipment	$188,523.57	$4,506.17	($152,443.81)	$0.00	$0.00	$0.00	$0.00	$40,585.93
RE 3941 Tools, Shop & Gar Eq HT	$116,134.30	$15,003.48	($12,048.08)	$0.00	$0.00	$0.00	$0.00	$119,089.70
RE 3942 Tools, Shop & Gar Eq LN	$807,699.41	$58,885.87	($95,446.99)	$0.00	$0.00	$0.00	$0.00	$771,138.29
RE 3943 Tools, Shop & Gar Eq SH	$56,422.23	$7,006.38	($3,252.66)	$0.00	$0.00	$0.00	$0.00	$60,175.95
RE 3944 Tools, Shop & Gar Eq GA	$79,261.48	$19,006.68	$0.00	$0.00	$0.00	$0.00	$0.00	$98,268.16
RE 3951 Laboratory Equip - Meter	$530,086.83	$17,536.33	($60,527.98)	$0.00	$0.00	$0.00	$0.00	$487,095.18
RE 3952 Laboratory Equip - Other	$99,311.93	$14,377.53	($7,436.15)	$0.00	$0.00	$0.00	$0.00	$106,253.31
RE 3953 Laboratory Equip - Field	$356,686.90	$32,614.32	($18,991.61)	$0.00	$0.00	$0.00	$0.00	$370,309.61
RE 397 Communication Equipment	$8,071,316.73	$214,982.49	($923,171.65)	$0.00	$0.00	$0.00	$0.00	$7,363,127.57
RE 398 Miscellaneous Equipment	$1,577,675.87	$127,261.13	($47,930.12)	$0.00	$0.00	$0.00	$0.00	$1,657,006.88
Depr Summ2 Subtotal:	$34,419,683.19	$2,640,952.99	($2,011,753.47)	($54,222.50)	$0.00	($8,711.91)	$0.00	$34,985,948.30
Franchise/License								
RE 302 Franchise, Charleston	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RE 302 Franchise, Columbia	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
None								
RE 389 Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Depr Summ2 Subtotal:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Software								
RE 303 Software	$14,131,330.68	$1,280,183.94	($1,715,902.93)	$0.00	$0.00	$0.00	$0.00	$13,695,611.69

Note: This report is filtered.

Set of Books Company Depr Summary2 Depr Group	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss	Ending Reserve
Financial								
Retail Electric								
Software								
RE 3036 Software, DER	$11,304.01	$15,072.01	$0.00	$0.00	$0.00	$0.00	$0.00	$26,376.02
Depr Summ2 Subtotal:	$14,142,634.69	$1,295,255.95	($1,715,902.93)	$0.00	$0.00	$0.00	$0.00	$13,721,987.71
Company Subtotal:	$939,006,332.41	$70,464,505.25	$20,694,180.17)	($5,384,084.77)	$1,530,788.63	($8,711.91)	$0.00	$984,914,649.44
Grand Total:	$3,808,606,492.73	;247,591,411.74	114,727,096.39)	$22,837,055.57)	$3,512,479.34	$881.12	($20,225.72)	$3,922,126,887.25

Note: This report is filtered.

gl_account	description	beginning_balance	additions
1010100	3010 - Organization Electric	14,988.33	0.00
1010100	3020 - Franchises and Consents Elec	4,643,673.29	0.00
1010100	3022 - Franchises and Consents Nucl	8,564,832.09	0.00
1010100	3030 - Misc Intangible Plant Elec	37,213,631.98	5,784,998.39
1010100	3032 - Misc Intangible Plant Nucl	26,894,535.58	629,683.72
1010100	3033 - Misc Cyber Intang Plant NU	179,529.63	0.00
1010100	3035 - CIPv5 Misc Intang Plant	562,525.19	0.00
1010100	3036 - DER Misc Intang Plant RE	0.00	0.00
1010100	3038 - Misc Intang Plant Leasehold	0.00	0.00
1010100	3100 - Elec Land Owned in Fee Steam	13,558,704.48	0.00
1010100	3110 - EStructures and Improvements	244,375,837.42	1,079,178.32
1010100	3118 - Leasehold Str & Improvements	0.00	0.00
1010100	3120 - Boiler Plant Equipment	1,035,990,355.27	13,466,351.34
1010100	3128 - Leasehold Boiler Plant Equip	0.00	0.00
1010100	3140 - Turbogenerator Units	420,595,098.72	16,797,707.28
1010100	3148 - Leasehold Turbogenerator Un	0.00	0.00
1010100	3150 - Accessory Electric Equipment	86,571,813.26	2,459,605.43
1010100	3158 - Leasehold Acc Elec Equipment	0.00	0.00
1010100	3160 - Misc Power Plant Equipment	30,769,457.33	311,802.16
1010100	3168 - Leasehold Misc Pwr Plt Equip	0.00	0.00
1010100	3201 - Land Owned in Fee Nuclear	880,611.29	0.00
1010100	3210 - Structures and Improvements	273,432,457.41	2,722,472.28
1010100	3220 - Reactor Plant Equipment	466,158,366.39	13,905,568.71
1010100	3230 - Turbogenerator Units	99,082,457.85	1,279,231.15
1010100	3240 - Accessory Electric Equipment	99,584,996.34	367,696.13
1010100	3250 - Misc Power Plant Equipment	92,263,535.95	1,757,583.45
1010100	3260 - Asset Retirement Cost	0.00	0.00
1010100	3301 - Land Owned in Fee Hydro	29,433,036.67	0.00
1010100	3310 - Structures and Improvements	49,518,315.72	251,575.24
1010100	3320 - Reservoirs, Dams & Waterways	111,368,294.03	278,889.62
1010100	3325 - Dams-Saluda HydroBackupDam	332,845,902.01	0.00
1010100	3330 - Water Wheels, Turbines & Gen	86,215,328.95	761,797.73
1010100	3340 - Accessory Electric Equipment	24,029,145.34	923,249.12
1010100	3350 - Misc Power Plant Equipment	9,883,856.20	729,236.00
1010100	3360 - Roads, Railroads & Bridges	1,817,517.43	0.00
1010100	3401 - Land Owned in Fee Other Prod	2,918,325.21	0.00
1010100	3402 - Land Rights & Easmt Other Pr	0.00	0.00
1010100	3410 - Structures and Improvements	41,161,589.97	609,441.57
1010100	3420 - Fuel Holders	8,173,752.37	48,779.78
1010100	3430 - Prime Movers	578,302,202.04	3,746,124.36
1010100	3440 - Generators	93,672,512.94	407,080.25
1010100	3450 - Accessory Electric Equipment	61,761,131.14	4,640.51
1010100	3455 - Access Elect Equipment CIPv5	1,832,657.67	0.00
1010100	3460 - Misc Power Plant Equipment	1,891,672.90	138,901.71
1010100	3501 - Trans. Land Owned in Fee	13,177,127.24	0.00
1010100	3502 - Transmn Land Rights & Easmt	65,461,681.28	4,027,561.46
1010100	3508 - Trns Land Rts & Easmt Lease	0.00	0.00
1010100	3520 - Structures & Improvements	4,388,606.33	6,555.26
1010100	3525 - CIPv5 Structures & Improvmt	1,306,897.24	0.00
1010100	3530 - Trans. Station Equipment	421,958,046.51	52,145,566.50
1010100	3535 - CIPv5 Trans Station Equipmt	6,591,800.37	6,658,809.39

1010100 3538 - Leasehold Station Equipment	1,463,910.93	39,971.02
1010100 3540 - Towers and Fixtures	5,356,060.53	0.00
1010100 3550 - Transm. Poles and Fixtures	355,606,971.08	24,119,256.87
1010100 3558 - Leasehold Poles & Fixtures	1,867,052.81	61,895.46
1010100 3561 - TransmOh Conductors, Devices	204,034,221.26	11,763,821.98
1010100 3562 - Overhead Fiber Optic Shl	2,860,037.03	193,458.34
1010100 3568 - Leasehold OH Conductor & Dev	1,412,854.46	0.00
1010100 3570 - Transm Underground Conduit	20,724,923.15	1,199,318.94
1010100 3580 - Transm UG Conductors Devices	55,525,319.29	5,910,018.89
1010100 3590 - Roads and Trails	73,766.16	0.00
1010100 3601-Elec Land Ownd in Fee Distn	22,543,851.62	2,276,626.20
1010100 3602-Elec Land Rights & Esmt Distr.	32,031,072.78	781,871.26
1010100 3608 - Distr Land Rts & Esmt Lease	90,300.04	0.00
1010100 3610-Elec Structures & Improvements	4,834,486.22	0.00
1010100 3618-Elec Leasehold Str & Impvemnts	66,541.62	0.00
1010100 3620-Elec Dist. Station Equipment	371,407,966.05	23,214,974.99
1010100 3625 - CIPv5 Dist Station Equipment	0.00	752,230.59
1010100 3628-Elec Leasehld Stat Equipmnt	3,443,523.40	443,874.82
1010100 3640-Elec Dist. Poles,Twrs,Fixtures	438,667,414.20	18,734,609.25
1010100 3650-Elec Overhd Conductors,Devices	477,678,933.60	19,388,560.25
1010100 3660-Elec Dist. Underground Conduit	145,091,601.78	6,261,810.53
1010100 3670-Elec Dist.UG Conductrs,Devices	424,608,187.19	23,358,186.85
1010100 3680- Elec Line Transformrs	452,997,784.58	16,462,927.13
1010100 3690 - Elec Services, Overhead	102,801,605.54	2,110,653.05
1010100 3691 - Elec Services, Underground	170,377,394.18	5,864,740.51
1010100 3700 - Electric Meters	19,472,301.60	930,252.94
1010100 3703 - Electric Meters/AMR/ERT	68,238,738.89	3,147,994.91
1010100 3704 - Electric Meters/AMI	11,144,418.51	6,676,426.50
1010100 3730-ELEC Street Lightng&Signal Sys	292,974,962.32	29,660,392.38
1010100 3891 - Elec Land Owned in Fee Genrl	8,375,756.82	0.00
1010100 3901 - Elec Structures& Improvemnts	98,577,716.33	511,236.53
1010100 3902 - Elec Structures& Imp Warehse	10,052,306.34	332,903.49
1010100 3908 - Elec LeasehldStr&Imp,Offices	145,185.39	0.00
1010100 3909 - Elec LeasehldStr&Imp,Warehse	111,031.25	0.00
1010100 3911 - Elec Office Furniture &Equip	8,154,600.05	3,340.40
1010100 3912 - Elec Info Systems (EDP)Equip	3,944,407.56	1,403,816.33
1010100 3913 - Elec OfficeDataHandlingEquip	320,006.98	0.00
1010100 3914 - Elec Info SystemsSCPSC ORDER	0.00	0.00
1010100 3919 - Elec Leasehold Furnishings	0.00	0.00
1010100 3921 - Elec Automobiles	43,766.62	0.00
1010100 3922 - Light Duty Trucks, 3000# GVW	10,412,445.98	0.00
1010100 3923 - Medium Duty Trucks, 13M-33M	1,634,176.74	0.00
1010100 3926 - Tractors, Trailer Hauling	410,591.91	0.00
1010100 3927 - Trailers	5,687,590.44	444,732.45
1010100 3929 - Misc Transportation Equipmnt	110,512.58	30,542.48
1010100 3930 - Elec Stores Equipment	270,241.41	0.00
1010100 3941 - Elec Power Hand Tools	520,468.78	26,831.32
1010100 3942 - Elec Line Tools	2,731,896.98	145,210.63
1010100 3943 - Elec Shop Tools	243,536.73	0.00
1010100 3944 - Elec Garage Equipment	283,505.59	0.00
1010100 3951 - Electric Meter Test Equipmnt	1,747,961.61	0.00
1010100 3952 - Elec Other Lab Test Equip	526,817.04	0.00
1010100 3953 - Elec Field Test Equipment	4,061,883.71	111,587.13
1010100 3960 - Power Operated Equipment	37,051,253.87	117,438.73
1010100 3970 - Elec Communication Equipment	6,924,129.37	547,045.53

1010100 3975 - CIPV5 Elec Comm Equip	0.00	265,650.15
1010100 3980 - Elec Miscellaneous Equipment	6,161,777.01	258,903.10
1010150 3320 - Reservoirs, Dams & Waterways	0.00	0.00
1010150 3325 - Dams-Saluda HydroBackupDam	0.00	0.00
1010160 3036 - DER Misc Intang Plant RE	150,720.51	0.00
1010160 3700 - Electric Meters	0.00	8,280.62
1010160 3705 - Electric Meters DER	1,339,940.16	1,723,428.86
1010180 3170 - ARC STEAM PRODUCTION	20,726,330.27	1,835,498.08
1010180 3260 - Asset Retirement Cost	22,893,825.83	0.00
1010180 3370 - ARC HYDRO PRODUCTION	(40,921.39)	0.00
1010180 3470 - ARC- OTHER PRODUCTION	(6,379,625.71)	913,261.68
1010180 3741 - ARC ELEC DISTRIB.TRANSFORMER	20,208.27	0.00
1010180 3742 - ARC ELEC DISTRIB.STRUCTURES	140,377.80	60,470.33
1010180 3991 - ARC Elec. General Property	(1,857.40)	0.00
1060100 3022 - Franchises and Consents Nucl	0.00	0.00
1060100 3030 - Misc Intangible Plant Elec	3,607,953.51	(1,897,114.89)
1060100 3032 - Misc Intangible Plant Nucl	332,524.02	307,152.23
1060100 3033 - Misc Cyber Intang Plant NU	8,819,497.22	171,701.75
1060100 3035 - CIPv5 Misc Intang Plant	0.00	0.00
1060100 3100 - Elec Land Owned in Fee Steam	1,948.44	13,434.58
1060100 3110 - EStructures and Improvements	13,574,544.95	58,173.30
1060100 3118 - Leasehold Str & Improvements	0.00	0.00
1060100 3120 - Boiler Plant Equipment	5,732,299.42	(443,953.14)
1060100 3128 - Leasehold Boiler Plant Equip	0.00	0.00
1060100 3140 - Turbogenerator Units	15,612,904.50	(14,895,934.15)
1060100 3148 - Leasehold Turbogenerator Un	0.00	0.00
1060100 3150 - Accessory Electric Equipment	902,672.28	(673,575.12)
1060100 3158 - Leasehold Acc Elec Equipment	0.00	0.00
1060100 3160 - Misc Power Plant Equipment	30,051.42	249,661.12
1060100 3168 - Leasehold Misc Pwr Plt Equip	0.00	0.00
1060100 3201 - Land Owned in Fee Nuclear	0.00	0.00
1060100 3210 - Structures and Improvements	28,618,831.51	2,522,168.78
1060100 3220 - Reactor Plant Equipment	53,179,939.80	84,458,135.16
1060100 3230 - Turbogenerator Units	15,907,055.03	(629,176.59)
1060100 3240 - Accessory Electric Equipment	12,738,422.08	2,883,193.46
1060100 3250 - Misc Power Plant Equipment	57,517,767.24	7,608,790.41
1060100 3251 - Misc Pwr Plt Equipment Cyber	1,659,154.47	13,008.73
1060100 3301 - Land Owned in Fee Hydro	0.00	52,095.82
1060100 3310 - Structures and Improvements	45,316.73	(10,980.10)
1060100 3320 - Reservoirs, Dams & Waterways	231,877.73	(231,360.44)
1060100 3325 - Dams-Saluda HydroBackupDam	0.00	0.00
1060100 3330 - Water Wheels, Turbines & Gen	588,882.94	(326,479.72)
1060100 3340 - Accessory Electric Equipment	0.00	3,957,045.52
1060100 3350 - Misc Power Plant Equipment	449,553.47	(394,073.37)
1060100 3360 - Roads, Railroads & Bridges	0.00	0.00
1060100 3401 - Land Owned in Fee Other Prod	0.00	0.00
1060100 3405 -LandRights&Easmt Other PrSCPC	0.00	0.00
1060100 3410 - Structures and Improvements	521,773.65	(512,384.52)
1060100 3420 - Fuel Holders	0.00	136,656.06
1060100 3425 - Fuel Holders FROM SCPC	0.00	0.00
1060100 3430 - Prime Movers	2,152,760.33	(1,980,235.77)
1060100 3440 - Generators	0.00	0.00
1060100 3450 - Accessory Electric Equipment	0.00	103,963.45
1060100 3455 - Access Elect Equipment CIPv5	0.00	0.00
1060100 3460 - Misc Power Plant Equipment	59,910.58	(34,713.42)

1060100 3501 - Trans. Land Owned in Fee	2,836,380.08	(2,836,380.08)
1060100 3502 - Transmn Land Rights & Easmt	4,307,328.07	1,130,526.78
1060100 3508 - Trns Land Rts & Easmt Lease	0.00	0.00
1060100 3520 - Structures & Improvements	0.00	0.00
1060100 3525 - CIPv5 Structures & Improvmt	403,492.57	485.08
1060100 3530 - Trans. Station Equipment	27,702,727.53	(12,803,607.61)
1060100 3535 - CIPv5 Trans Station Equipmt	5,380,795.20	(3,933,682.45)
1060100 3538 - Leasehold Station Equipment	1,323.81	(1,323.81)
1060100 3540 - Towers and Fixtures	0.00	0.00
1060100 3550 - Transm. Poles and Fixtures	25,124,852.95	10,771,909.21
1060100 3558 - Leasehold Poles & Fixtures	0.00	0.00
1060100 3561 - TransmOh Conductors, Devices	8,445,933.13	459,941.75
1060100 3562 - Overhead Fiber Optic Shl	168,206.87	(168,206.87)
1060100 3568 - Leasehold OH Conductor & Dev	0.00	0.00
1060100 3570 - Transm Underground Conduit	0.00	0.00
1060100 3580 - Transm UG Conductors Devices	7,109,167.77	(7,109,167.77)
1060100 3590 - Roads and Trails	0.00	0.00
1060100 3601-Elec Land Ownd in Fee Distn	0.00	0.00
1060100 3602-Elec Land Rights & Esmt Distr.	639,140.65	(148,238.88)
1060100 3610-Elec Structures & Improvements	0.00	0.00
1060100 3618-Elec Leasehold Str & Impvemnts	0.00	0.00
1060100 3620-Elec Dist. Station Equipment	8,413,074.43	(4,472,451.17)
1060100 3625 - CIPv5 Dist Station Equipment	321,153.06	(321,153.06)
1060100 3628-Elec Leasehld Stat Equipmnt	17,877.29	(17,877.29)
1060100 3640-Elec Dist. Poles,Twrs,Fixtures	9,161,519.85	6,586,160.97
1060100 3650-Elec Overhd Conductors,Devices	13,779,736.51	(3,194,201.02)
1060100 3660-Elec Dist. Underground Conduit	3,924,344.41	(893,924.43)
1060100 3670-Elec Dist.UG Conductrs,Devices	17,239,773.74	(463,898.36)
1060100 3680- Elec Line Transformrs	8,040,106.82	1,521,204.57
1060100 3690 - Elec Services, Overhead	2,910,680.49	(132,729.19)
1060100 3691 - Elec Services, Underground	5,140,755.20	682,300.90
1060100 3700 - Electric Meters	4,307,797.93	424,617.69
1060100 3703 - Electric Meters/AMR/ERT	2,950,635.76	(2,486,590.70)
1060100 3704 - Electric Meters/AMI	2,392,385.11	(2,381,250.87)
1060100 3705 - Electric Meters DER	0.00	0.00
1060100 3730-ELEC Street Lightng&Signal Sys	16,882,995.53	(10,428,065.56)
1060100 3891 - Elec Land Owned in Fee Genrl	0.00	0.00
1060100 3901 - Elec Structures& Improvemnts	25,852.51	27,167.11
1060100 3902 - Elec Structures& Imp Warehse	0.00	0.00
1060100 3908 - Elec LeasehldStr&Imp,Offices	0.00	0.00
1060100 3911 - Elec Office Furniture &Equip	0.00	0.00
1060100 3912 - Elec Info Systems (EDP)Equip	1,294,840.21	(1,294,840.21)
1060100 3913 - Elec OfficeDataHandlingEquip	0.00	0.00
1060100 3914 - Elec Info SystemsSCPSC ORDER	0.00	0.00
1060100 3922 - Light Duty Trucks, 3000# GVW	0.00	0.00
1060100 3923 - Medium Duty Trucks, 13M-33M	0.00	0.00
1060100 3926 - Tractors, Trailer Hauling	0.00	0.00
1060100 3927 - Trailers	43,038.53	(43,038.53)
1060100 3929 - Misc Transportation Equipmnt	0.00	0.00
1060100 3930 - Elec Stores Equipment	0.00	0.00
1060100 3941 - Elec Power Hand Tools	0.00	2,566.16
1060100 3942 - Elec Line Tools	31,578.10	(21,261.63)
1060100 3943 - Elec Shop Tools	0.00	0.00
1060100 3944 - Elec Garage Equipment	0.00	0.00
1060100 3951 - Electric Meter Test Equipmnt	0.00	0.00

1060100 3952 - Elec Other Lab Test Equip	0.00	0.00
1060100 3953 - Elec Field Test Equipment	0.00	60,594.78
1060100 3960 - Power Operated Equipment	0.00	0.00
1060100 3970 - Elec Communication Equipment	612,725.21	(612,725.21)
1060100 3975 - CIPV5 Elec Comm Equip	0.00	0.00
1060100 3980 - Elec Miscellaneous Equipment	32,478.25	1,750.21
1060160 3705 - Electric Meters DER	(126,435.34)	616,960.07
1180710 6030 - Misc Intangible Plant, Commo	133,935,912.75	13,361,338.28
1180710 6891 - Land Owned in Fee, Common	18,840,141.37	0.00
1180710 6892 - Land Rights, Common	1,028.94	0.00
1180710 6901 - Structures/Imp - Office, Com	137,456,758.43	3,353,739.48
1180710 6902 - Structures/Imp - Warhse, Com	23,455,354.16	0.00
1180710 6908 - Leasehold - Offices, Comm	14,466,067.32	398,790.95
1180710 6909 - Leasehold - Warehouse, Com	293,437.21	0.00
1180710 6911 - Office Furniture & Eq, Com	8,509,620.30	29,311.17
1180710 6912 - Information Systems (EDP) Eq	2,411,790.37	0.00
1180710 6913 - Office Data Handling Eq, Com	1,154,301.00	0.00
1180710 6914 - Infor Systems (SCPSC ORDER)	0.00	0.00
1180710 6921 - Automobiles, Common	210,512.89	0.00
1180710 6922 - Light Dty Trucks 13000#, Com	5,245,562.46	0.00
1180710 6923 - Medium Dty Trucks 13M-33M	580,883.06	0.00
1180710 6927 - Trailers, Common	530,474.57	25,428.54
1180710 6929 - Misc Transportatn Eq, Common	0.00	0.00
1180710 6930 - Stores Equipment, Common	54,391.76	0.00
1180710 6941 - Power Hand Tools, Common	6,027.25	0.00
1180710 6943 - Shop Tools, Common	283,787.12	0.00
1180710 6944 - Garage Equipment, Common	1,822,517.46	15,983.78
1180710 6952 - Other Laboratory Tst Eq, Com	65,056.34	0.00
1180710 6953 - Field Test Equipment, Common	86,637.39	0.00
1180710 6960 - Power Operated Equip, Common	3,108,129.27	27,185.71
1180710 6970 - Communication Equipment, Com	7,317,255.37	227,394.52
1180710 6978 - Leasehold - Comm Eq, Common	565,776.48	9,855.53
1180710 6980 - Miscellaneous Equip, Common	5,981,907.47	555,024.00
1180712 6991 - ARC,Common Gen Plant tanks	(2,216.55)	8,077.29
1180712 6992 - ARC,Common Gen Plt Struc	83,086.27	584,467.99
1180760 6030 - Misc Intangible Plant, Commo	162,374.86	8,758,131.30
1180760 6891 - Land Owned in Fee, Common	0.00	0.00
1180760 6901 - Structures/Imp - Office, Com	3,712,781.02	(2,924,589.81)
1180760 6902 - Structures/Imp - Warhse, Com	0.00	5,666.64
1180760 6908 - Leasehold - Offices, Comm	0.00	0.00
1180760 6909 - Leasehold - Warehouse, Com	0.00	0.00
1180760 6911 - Office Furniture & Eq, Com	9,726.34	(9,726.34)
1180760 6912 - Information Systems (EDP) Eq	0.00	0.00
1180760 6913 - Office Data Handling Eq, Com	0.00	0.00
1180760 6922 - Light Dty Trucks 13000#, Com	0.00	0.00
1180760 6927 - Trailers, Common	0.00	0.00
1180760 6943 - Shop Tools, Common	0.00	13,807.50
1180760 6944 - Garage Equipment, Common	7,602.12	(7,602.12)
1180760 6960 - Power Operated Equip, Common	0.00	0.00
1180760 6970 - Communication Equipment, Com	92,273.55	132,232.80
1180760 6978 - Leasehold - Comm Eq, Common	0.00	0.00
1180760 6980 - Miscellaneous Equip, Common	99,783.07	43,917.32

	Period Beginning:	October-2016			
	Period Ending:	September-2017			

retirements	trans/adjust	book balance	proforma add	proforma ret	proforma trans/adjust
0.00	0.00	14,988.33			
0.00	0.00	4,643,673.29			
0.00	0.00	8,564,832.09			
(2,252,398.00)	35,656.06	40,781,888.43			
(10,150,112.22)	0.00	17,374,107.08			
0.00	0.00	179,529.63			
0.00	45,799.70	608,324.89			
0.00	0.00	0.00			
0.00	0.00	0.00			
0.00	0.00	13,558,704.48			
(1,434,137.54)	0.00	244,020,878.20			
0.00	0.00	0.00			
(6,055,785.85)	0.00	1,043,400,920.76			
0.00	0.00	0.00			
(8,970,885.55)	(81,455.76)	428,340,464.69			
0.00	0.00	0.00			
(179,082.91)	0.00	88,852,335.78			
0.00	0.00	0.00			
(575,481.21)	0.00	30,505,778.28			
0.00	0.00	0.00			
0.00	0.00	880,611.29			
(1,546,897.83)	(1,331.03)	274,606,700.83			
(7,042,148.74)	0.00	473,021,786.36			
(643,127.73)	0.00	99,718,561.27			
(275,510.90)	1,331.03	99,678,512.60			
(1,221,715.16)	0.00	92,799,404.24			
0.00	0.00	0.00			
0.00	(341.81)	29,432,694.86			
(20,796.84)	0.00	49,749,094.12			
(254,199.58)	0.00	111,392,984.07			
0.00	0.00	332,845,902.01			
(24,329.45)	0.00	86,952,797.23			
(107,209.70)	0.00	24,845,184.76			
(160,250.60)	0.00	10,452,841.60			
0.00	0.00	1,817,517.43			
0.00	0.00	2,918,325.21			
0.00	0.00	0.00			
(12,995.69)	0.00	41,758,035.85			
(763,929.02)	(1,996.43)	7,456,606.70			
(1,245,674.70)	(67.12)	580,802,584.58			
(482,498.26)	67.12	93,597,162.05			
(23,650.38)	0.00	61,742,121.27			
0.00	0.00	1,832,657.67			
(13,645.55)	1,996.43	2,018,925.49			
0.00	(619,979.83)	12,557,147.41			
(6,319.90)	(187.84)	69,482,735.00			
0.00	0.00	0.00			
(139.92)	0.00	4,395,021.67			
0.00	0.00	1,306,897.24			
(2,612,630.11)	582,772.32	472,073,755.22			
0.00	0.00	13,250,609.76			

0.00	0.00	1,503,881.95
(1,862.40)	0.00	5,354,198.13
(1,162,654.75)	187,868.93	378,751,442.13
0.00	0.00	1,928,948.27
(1,112,897.94)	(195,243.93)	214,489,901.37
(35,850.40)	0.00	3,017,644.97
0.00	0.00	1,412,854.46
(1,475,128.08)	(900,000.00)	19,549,114.01
(4,635,700.77)	900,000.00	57,699,637.41
0.00	0.00	73,766.16
0.00	(417,120.17)	24,403,357.65
0.00	1,037,287.85	33,850,231.89
0.00	0.00	90,300.04
(1,876.13)	0.00	4,832,610.09
0.00	0.00	66,541.62
(2,643,230.81)	(1,222,560.61)	390,757,149.62
0.00	0.00	752,230.59
(31,097.09)	647,163.29	4,503,464.42
(3,473,385.55)	(422.78)	453,928,215.12
(2,785,834.18)	(29,603.06)	494,252,056.61
(87,719.29)	0.01	151,265,693.03
(1,657,649.82)	29,974.98	446,338,699.20
(4,108,823.41)	(430.17)	465,351,458.13
(181,377.76)	0.00	104,730,880.83
(16,460.70)	0.00	176,225,673.99
(171,225.92)	608,089.43	20,839,418.05
(599,294.41)	(548,095.54)	70,239,343.85
(1,222,384.13)	(51,713.27)	16,546,747.61
(2,661,522.04)	481.01	319,974,313.67
0.00	0.00	8,375,756.82
(355,177.89)	18,342.16	98,752,117.13
(49,678.32)	0.00	10,335,531.51
0.00	0.00	145,185.39
0.00	0.00	111,031.25
(54,904.63)	(17,908.29)	8,085,127.53
(494,174.86)	0.00	4,854,049.03
(18,667.03)	0.00	301,339.95
0.00	0.00	0.00
0.00	0.00	0.00
(43,766.62)	0.00	0.00
(667,129.49)	0.00	9,745,316.49
0.00	0.00	1,634,176.74
0.00	0.00	410,591.91
(14,933.77)	0.00	6,117,389.12
0.00	0.00	141,055.06
(152,443.81)	0.00	117,797.60
(25,695.39)	0.00	521,604.71
(211,310.72)	0.00	2,665,796.89
(15,293.75)	0.00	228,242.98
(4,775.28)	0.00	278,730.31
(221,881.14)	0.00	1,526,080.47
(34,521.97)	0.00	492,295.07
(174,926.28)	0.00	3,998,544.56
(6,042,598.89)	0.00	31,126,093.71
(1,370,884.78)	0.00	6,100,290.12

0.00	0.00	265,650.15	
(91,418.91)	0.00	6,329,261.20	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	150,720.51	
0.00	(8,280.62)	0.00	
(846.56)	0.00	3,062,522.46	
(25,050,558.91)	0.00	(2,488,730.56)	
0.00	0.00	22,893,825.83	
40,921.39	0.00	0.00	
125,847.29	0.00	(5,340,516.74)	
0.00	0.00	20,208.27	
0.00	0.00	200,848.13	
1,857.40	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	1,710,838.62	
0.00	0.00	639,676.25	104.33
0.00	(8,809,097.22)	182,101.75	
0.00	0.00	0.00	
0.00	0.00	15,383.02	
0.00	0.00	13,632,718.25	
0.00	0.00	0.00	
0.00	0.00	5,288,346.28	
0.00	0.00	0.00	
0.00	0.00	716,970.35	
0.00	0.00	0.00	
0.00	0.00	229,097.16	
0.00	0.00	0.00	
0.00	0.00	279,712.54	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	31,141,000.29	
0.00	0.00	137,638,074.96	
0.00	0.00	15,277,878.44	
0.00	0.00	15,621,615.54	
0.00	0.00	65,126,557.65	
0.00	8,809,097.22	10,481,260.42	
0.00	0.00	52,095.82	
0.00	0.00	34,336.63	
0.00	0.00	517.29	
0.00	0.00	0.00	
0.00	0.00	262,403.22	
0.00	0.00	3,957,045.52	
0.00	0.00	55,480.10	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	9,389.13	
0.00	0.00	136,656.06	
0.00	0.00	0.00	
0.00	0.00	172,524.56	
0.00	0.00	0.00	
0.00	0.00	103,963.45	
0.00	0.00	0.00	
0.00	0.00	25,197.16	

0.00	0.00	0.00	
0.00	0.00	5,437,854.85	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	403,977.65	
0.00	0.00	14,899,119.92	
0.00	0.00	1,447,112.75	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	35,896,762.16	1,126.89
0.00	0.00	0.00	
0.00	0.00	8,905,874.88	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	490,901.77	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	3,940,623.26	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	15,747,680.82	(15.43)
0.00	0.00	10,585,535.49	
0.00	0.00	3,030,419.98	
0.00	0.00	16,775,875.38	
0.00	0.00	9,561,311.39	
0.00	0.00	2,777,951.30	
0.00	0.00	5,823,056.10	
0.00	0.00	4,732,415.62	
0.00	0.00	464,045.06	
0.00	0.00	11,134.24	
0.00	0.00	0.00	
0.00	0.00	6,454,929.97	
0.00	0.00	0.00	
0.00	0.00	53,019.62	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
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0.00	0.00	0.00	
0.00	0.00	2,566.16	
0.00	0.00	10,316.47	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	

0.00	0.00	0.00	
0.00	0.00	60,594.78	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	34,228.46	
0.00	0.00	490,524.73	
(26,881,389.96)	0.00	120,415,861.07	
0.00	0.00	18,840,141.37	
0.00	0.00	1,028.94	
(109,839.48)	527.36	140,701,185.79	
0.00	0.00	23,455,354.16	
0.00	0.00	14,864,858.27	
0.00	0.00	293,437.21	
(135,452.75)	0.00	8,403,478.72	
(961,421.75)	0.00	1,450,368.62	
(25,091.05)	0.00	1,129,209.95	
0.00	0.00	0.00	
(74,767.79)	0.00	135,745.10	
(319,119.02)	0.00	4,926,443.44	
(34,951.25)	0.00	545,931.81	
(1,195.00)	0.00	554,708.11	
0.00	0.00	0.00	
(54,391.76)	0.00	0.00	
(889.49)	0.00	5,137.76	
(3,887.12)	0.00	279,900.00	
(182,657.29)	0.00	1,655,843.95	
0.00	0.00	65,056.34	
(3,854.99)	0.00	82,782.40	
(86,750.67)	0.00	3,048,564.31	
(1,442,076.24)	0.00	6,102,573.65	
0.00	0.00	575,632.01	
(222,801.77)	0.00	6,314,129.70	
0.00	0.00	5,860.74	
0.00	0.00	667,554.26	
0.00	0.00	8,920,506.16	
0.00	0.00	0.00	
0.00	0.00	788,191.21	
0.00	0.00	5,666.64	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	0.00	
0.00	0.00	13,807.50	
0.00	0.00	0.00	4,009.08
0.00	0.00	0.00	
0.00	0.00	224,506.35	
0.00	0.00	0.00	
0.00	0.00	143,700.39	

ending balance
14,988.33
4,643,673.29
8,564,832.09
40,781,888.43
17,374,107.08
179,529.63
608,324.89
0.00
0.00
13,558,704.48
244,020,878.20
0.00
1,043,400,920.76
0.00
428,340,464.69
0.00
88,852,335.78
0.00
30,505,778.28
0.00
880,611.29
274,606,700.83
473,021,786.36
99,718,561.27
99,678,512.60
92,799,404.24
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49,749,094.12
111,392,984.07
332,845,902.01
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24,845,184.76
10,452,841.60
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2,918,325.21
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41,758,035.85
7,456,606.70
580,802,584.58
93,597,162.05
61,742,121.27
1,832,657.67
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12,557,147.41
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4,395,021.67
1,306,897.24
472,073,755.22
13,250,609.76

1,503,881.95
5,354,198.13
378,751,442.13
1,928,948.27
214,489,901.37
3,017,644.97
1,412,854.46
19,549,114.01
57,699,637.41
73,766.16
24,403,357.65
33,850,231.89
90,300.04
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66,541.62
390,757,149.62
752,230.59
4,503,464.42
453,928,215.12
494,252,056.61
151,265,693.03
446,338,699.20
465,351,458.13
104,730,880.83
176,225,673.99
20,839,418.05
70,239,343.85
16,546,747.61
319,974,313.67
8,375,756.82
98,752,117.13
10,335,531.51
145,185.39
111,031.25
8,085,127.53
4,854,049.03
301,339.95
0.00
0.00
0.00
9,745,316.49
1,634,176.74
410,591.91
6,117,389.12
141,055.06
117,797.60
521,604.71
2,665,796.89
228,242.98
278,730.31
1,526,080.47
492,295.07
3,998,544.56
31,126,093.71
6,100,290.12

265,650.15
6,329,261.20
0.00
0.00
150,720.51
0.00
3,062,522.46
(2,488,730.56)
22,893,825.83
0.00
(5,340,516.74)
20,208.27
200,848.13
0.00
0.00
1,710,838.62
639,780.58
182,101.75
0.00
15,383.02
13,632,718.25
0.00
5,288,346.28
0.00
716,970.35
0.00
229,097.16
0.00
279,712.54
0.00
0.00
31,141,000.29
137,638,074.96
15,277,878.44
15,621,615.54
65,126,557.65
10,481,260.42
52,095.82
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517.29
0.00
262,403.22
3,957,045.52
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0.00
0.00
9,389.13
136,656.06
0.00
172,524.56
0.00
103,963.45
0.00
25,197.16

0.00
5,437,854.85
0.00
0.00
403,977.65
14,899,119.92
1,447,112.75
0.00
0.00
35,897,889.05
0.00
8,905,874.88
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490,901.77
0.00
0.00
3,940,623.26
0.00
0.00
15,747,665.39
10,585,535.49
3,030,419.98
16,775,875.38
9,561,311.39
2,777,951.30
5,823,056.10
4,732,415.62
464,045.06
11,134.24
0.00
6,454,929.97
0.00
53,019.62
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2,566.16
10,316.47
0.00
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0.00
60,594.78
0.00
0.00
0.00
34,228.46
490,524.73
120,415,861.07
18,840,141.37
1,028.94
140,701,185.79
23,455,354.16
14,864,858.27
293,437.21
8,403,478.72
1,450,368.62
1,129,209.95
0.00
135,745.10
4,926,443.44
545,931.81
554,708.11
0.00
0.00
5,137.76
279,900.00
1,655,843.95
65,056.34
82,782.40
3,048,564.31
6,102,573.65
575,632.01
6,314,129.70
5,860.74
667,554.26
8,920,506.16
0.00
788,191.21
5,666.64
0.00
0.00
0.00
0.00
0.00
0.00
0.00
13,807.50
4,009.08
0.00
224,506.35
0.00
143,700.39

South Carolina Electric & Gas Company
Cash Working Capital Allowance
Net Income for Return and Rate Base

Attachment B

		Total Company-Electric			FERC Wholesale-Electric			Retail Electric		
Line No	**Description**	**Regulatory Per Books (1) $**	**Acct. & Pro Forma Adjs. (2) $**	**As Adjusted (3) $**	**Regulatory Per Books (4) $**	**Acct. & Pro Forma Adjs. (5) $**	**As Adjusted (6) $**	**Regulatory Per Books (7) $**	**Acct. & Pro Forma Adjs. (8) $**	**As Adjusted (9) $**
1.	Revenues	2,626,725,028	(452,787,901)	2,173,937,127	52,899,718	0	52,899,718	2,573,825,310	(452,787,901)	2,121,037,409
2.	Expenses									
3.	Operation & Maintenance									
4.	Fuel Used in Elec. Gen.	649,424,435	0	649,424,435	26,137,271	0	26,137,271	623,287,164	0	623,287,164
5.	Purchased Power	96,105,480	0	96,105,480	3,089,591	0	3,089,591	93,015,889	0	93,015,889
6.	Other	502,073,959	4,840,606	506,914,565	11,378,237	448,566	11,826,803	490,695,722	4,392,040	495,087,762
7.	Depreciation	274,006,765	2,534,922	276,541,687	6,262,416	44,216	6,306,632	267,744,349	2,490,706	270,235,055
8.	Taxes Other Than Income	210,682,693	4,045,692	214,728,385	4,613,249	133,527	4,746,776	206,069,444	3,912,165	209,981,609
9.	Income Taxes - State	69,042,819	(16,018,491)	53,024,328	1,537,045	196,319	1,733,364	67,505,774	(16,214,810)	51,290,964
10.	Income Taxes – Federal	446,544,720	(106,522,968)	340,021,752	9,783,399	1,305,516	11,088,915	436,761,321	(107,828,484)	328,932,837
11.	Deferred Income Taxes-Net	(319,625,973)	0	(319,625,973)	(5,636,974)	0	(5,636,974)	(313,988,999)	0	(313,988,999)
12.	Investment Tax Credit	(1,276,100)	0	(1,276,100)	(26,537)	0	(26,537)	(1,249,563)	0	(1,249,563)
13.	Investment Tax Credit - See above									
14.	Total Operating Expenses	1,926,978,798	(111,120,239)	1,815,858,559	57,137,697	2,128,144	59,265,841	1,869,841,101	(113,248,383)	1,756,592,718
15.	Operating Return	699,746,230	(341,667,662)	358,078,568	(4,237,979)	(2,128,144)	(6,366,123)	703,984,209	(339,539,518)	364,444,691
16.	Add: Customer Growth	3,407,903	(1,643,670)	1,764,233	0	0	0	3,407,903	(1,643,670)	1,764,233
17.	Less: Interest on Customer Deposits	(1,114,066)	0	(1,114,066)	0	0	0	(1,114,066)	0	(1,114,066)
18.	**Total Income for Return**	702,040,067	(343,311,332)	358,728,735	(4,237,979)	(2,128,144)	(6,366,123)	706,278,046	(341,183,188)	365,094,858

South Carolina Electric & Gas Company
Cash Working Capital Allowance
Net Income for Return and Rate Base

Attachment B

		Total Company-Electric			FERC Wholesale-Electric			Retail Electric		
Line No	**Description**	**Regulatory Per Books (1) $**	**Acct. & Pro Forma Adjs. (2) $**	**As Adjusted (3) $**	**Regulatory Per Books (4) $**	**Acct. & Pro Forma Adjs. (5) $**	**As Adjusted (6) $**	**Regulatory Per Books (7) $**	**Acct. & Pro Forma Adjs. (8) $**	**As Adjusted (9) $**
19.	**Original Cost Rate Base**									
20.	Plant in Service	9,847,762,591	(5,553,946)	9,842,208,645	204,788,161	(115,482)	204,672,679	9,642,974,430	(5,438,464)	9,637,535,966
21.	Const. Work in Progress	5,044,195,701	(4,835,688,277)	208,507,424	159,144,894	(153,291,280)	5,853,614	4,885,050,807	(4,682,396,997)	202,653,810
22.	Total Gross Plant	14,891,958,292	(4,841,242,223)	10,050,716,069	363,933,055	(153,406,762)	210,526,293	14,528,025,237	(4,687,835,461)	9,840,189,776
23.	Less: Accum. Depreciation	3,865,657,956	666,364	3,866,324,320	88,349,490	1,510	88,351,000	3,777,308,466	664,854	3,777,973,320
24.	Less: Accum. Deferred Income Taxes (Lib. Depreciation)	(1,168,308,900)	(306,585,400)	(1,474,894,300)	(24,295,451)	(9,718,757)	(34,014,208)	(1,144,013,449)	(296,866,643)	(1,440,880,092)
25.	Less: Customer Deposits	(54,354,631)	0	(54,354,631)	0	0	0	(54,354,631)	0	(54,354,631)
26.	Add: Materials & Supplies	437,304,695	14,880,195	452,184,890	15,108,099	605,624	15,713,723	422,196,596	14,274,571	436,471,167
27.	Add: Plant Held in Future Use	0	0	0	0	0	0	0	0	0
28.	Add: Cash Working Capital	20,431,080	605,075	21,036,155	2,956,606	56,070	3,012,676	17,474,474	549,005	18,023,479
29.	Add: Deferred Debits/Credits	64,562,120	19,454	64,581,574	660,400	526	660,926	63,901,720	18,928	63,920,648
30.	**End of Year Rate Base**	10,325,934,700	(5,132,989,263)	5,192,945,437	270,013,219	(162,464,809)	107,548,410	10,055,921,481	(4,970,524,454)	5,085,397,027
31.	**Rates of Return**	6.80%		6.91%	-1.57%		-5.92%	7.02%		7.18%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF FIRST CONTINUING AUDIT
DOCKET NOs. 2017-207-E, 2017-305-E, AND 2017-370-E
RESPONSE 1-40

SCE&G

	(COAL)				(NO. 2 FUEL OIL)		
Month	**Tons**	**End $**	**Avg Cost/Ton**	**Forecasted Burn Days Supply**	**Gallons**	**End $**	**Avg Cost/Gallon**
October-16	284,759.99	$ 21,629,029.95	$ 75.9553	26.74	8,051,280.57	$ 19,222,699.50	$ 2.3875
November-16	348,026.58	$ 27,296,982.67	$ 78.4336	32.68	8,032,768.57	$ 19,184,026.24	$ 2.3882
December-16	295,743.56	$ 23,958,115.71	$ 81.0098	27.77	8,233,945.25	$ 19,549,246.88	$ 2.3742
January-17	253,543.46	$ 20,857,067.69	$ 82.2623	23.81	8,138,248.65	$ 19,362,947.23	$ 2.3793
February-17	222,414.69	$ 19,051,277.39	$ 85.6566	20.89	8,237,281.68	$ 19,547,075.26	$ 2.3730
March-17	321,810.84	$ 26,684,756.41	$ 82.9206	30.22	7,963,623.88	$ 19,066,827.79	$ 2.3942
April-17	299,194.80	$ 24,047,486.76	$ 80.3740	28.10	8,191,036.26	$ 19,460,260.93	$ 2.3758
May-17	320,084.77	$ 25,984,091.78	$ 81.1788	30.06	8,117,050.67	$ 19,322,699.37	$ 2.3805
June-17	305,465.02	$ 24,368,377.96	$ 79.7747	28.69	8,172,249.03	$ 19,376,969.72	$ 2.3711
July-17	294,440.25	$ 23,176,140.41	$ 78.7125	27.65	8,159,244.86	$ 19,352,355.54	$ 2.3718
August-17	233,875.63	$ 18,038,606.46	$ 77.1291	21.96	8,240,332.25	$ 19,595,203.74	$ 2.3780
September-17	205,368.63	$ 16,313,212.54	$ 79.4338	19.29	8,110,420.57	$ 19,373,732.36	$ 2.3887

GENCO

	(COAL)				(NO. 2 FUEL OIL)		
Month	**Tons**	**End $**	**Avg Cost/Ton**	**Forecasted Burn Days Supply**	**Gallons**	**End $**	**Avg Cost/Gallon**
October-16	232,494.87	$ 20,045,441.95	$ 86.2189	41.68	563,679.10	$ 928,237.49	$ 1.6467
November-16	233,565.93	$ 20,042,477.59	$ 85.8108	41.87	583,466.10	$ 961,971.44	$ 1.6487
December-16	172,517.46	$ 13,799,891.31	$ 79.9913	30.93	608,100.10	$ 1,013,499.71	$ 1.6667
January-17	140,151.80	$ 10,744,994.52	$ 76.6668	25.13	598,046.10	$ 997,430.81	$ 1.6678
February-17	118,913.16	$ 8,901,641.50	$ 74.8583	21.32	602,257.10	$ 1,006,372.80	$ 1.6710
March-17	125,155.59	$ 10,021,331.83	$ 80.0710	22.44	596,500.10	$ 998,294.55	$ 1.6736
April-17	117,995.77	$ 9,617,386.65	$ 81.5062	21.15	646,220.10	$ 1,097,279.34	$ 1.6980
May-17	89,638.03	$ 7,381,563.01	$ 82.3486	16.07	652,153.10	$ 1,106,732.53	$ 1.6970
June-17	144,040.05	$ 11,520,077.69	$ 79.9783	25.82	655,372.10	$ 1,101,975.59	$ 1.6815
July-17	135,791.83	$ 10,969,802.84	$ 80.7840	24.34	611,461.10	$ 1,027,325.28	$ 1.6801
August-17	145,867.40	$ 11,906,864.59	$ 81.6280	26.15	681,136.10	$ 1,151,835.08	$ 1.6910
September-17	167,469.21	$ 13,962,324.52	$ 83.3725	30.02	677,210.10	$ 1,147,637.64	$ 1.6947

TOTAL

	(COAL)				(NO. 2 FUEL OIL)		
Month	**Tons**	**End $**	**Avg Cost/Ton**	**Forecasted Burn Days Supply**	**Gallons**	**End $**	**Avg Cost/Gallon**
October-16	517,254.86	$ 41,674,471.90	$ 80.5685	31.88	8,614,959.67	$ 20,150,936.99	$ 2.3391
November-16	581,592.51	$ 47,339,460.26	$ 81.3963	35.84	8,616,234.67	$ 20,145,997.68	$ 2.3381
December-16	468,261.02	$ 37,758,007.02	$ 80.6345	28.86	8,842,045.35	$ 20,562,746.59	$ 2.3256
January-17	393,695.26	$ 31,602,062.21	$ 80.2704	24.26	8,736,294.75	$ 20,360,378.04	$ 2.3306
February-17	341,327.85	$ 27,952,918.89	$ 81.8946	21.04	8,839,538.78	$ 20,553,448.06	$ 2.3252
March-17	446,966.43	$ 36,706,088.24	$ 82.1227	27.55	8,560,123.98	$ 20,065,122.34	$ 2.3440
April-17	417,190.57	$ 33,664,873.41	$ 80.6942	25.71	8,837,256.36	$ 20,557,540.27	$ 2.3262
May-17	409,722.80	$ 33,365,654.79	$ 81.4347	25.25	8,769,203.77	$ 20,429,431.90	$ 2.3297
June-17	449,505.07	$ 35,888,455.65	$ 79.8399	27.70	8,827,621.13	$ 20,478,945.31	$ 2.3199
July-17	430,232.08	$ 34,145,943.25	$ 79.3663	26.51	8,770,705.96	$ 20,379,680.82	$ 2.3236
August-17	379,743.03	$ 29,945,471.05	$ 78.8572	23.40	8,921,468.35	$ 20,747,038.82	$ 2.3255
September-17	372,837.84	$ 30,275,537.06	$ 81.2030	22.98	8,787,630.67	$ 20,521,370.00	$ 2.3353

SCE&G Electric Operations
Account 9090000 Accounts Payable Details
12 Months Ended September 2017

No Activity during this period

South Carolina Electric & Gas Company
Office of Regulatory Staff's Continuing
Audit Information Request
Docket No. 2017-207-E (2nd Continuing AIR)
Docket No. 2017-305-E (1st Continuing AIR)
Docket No. 2017-370-E (1st Continuing AIR)
Response 1-60

			Balance @ 9/30/2017
Deferred Debits			**7,570,599,322**
Unamortized Debt Expenses			**34,146,063**
	1810002	Debt Exp $39.480m 4pct Bonds	292,294
	1810006	Dept Exp $14.735m 3.625pct Bon	120,930
	1810007	Unam Debt Exp 400m 4 6 6152043	3,628,623
	1810008	Unam Debt Exp 5.1% 500m Bonds	5,077,274
	1810104	Unam Dbt Exp 6.625% Due 2/1/32	1,366,399
	1810106	Un Debt Exp 5 8% - 1 15 33	909,080
	1810117	Un Dbt Ex 100m 5 25 Bnd3 1 35	599,652
	1810119	Unam Debt Exp 250m 6 05% Bonds	3,762,913
	1810121	Un Debt Exp 6 5 Series Due	237,888
	1810124	Unam Debt Exp 6 25% Due 2036	775,485
	1810125	Unam Debt Exp - 35m Irb	347,973
	1810136	Un Dbt Exp - 2009 Fmb	1,133,320
	1810145	Unam Dbt Exp $250m Fmb Due 2-1	2,780,125
	1810161	Unam Dbt Exp 5 3% Due 5 15 33	1,393,421
	1810163	Un Dbt Exp 250m 5 25% 11 1 18	176,830
	1810165	Unam Dbt Exp $300m 4.5% Due 6/	3,666,482
	1810167	Unam Debt Exp 4.1% Due 6/15/46	3,558,637
	1810197	Unam Debt Exp 30m Fmb 3 22	134,597
	1810199	Unamort Debt Exp 250m	4,184,140
Other Regulatory Assets			**2,025,704,370**
	1822100	Unrecovered Plant Parr	498,661
	1822101	Unrecov Plnt Contra Parr	(498,661)
	1822102	Unrecov Plant Hagood	876,914
	1822103	Unrecov Plnt Contra Hagood	(876,914)
	1822104	Unrecov Plnt Defective Stm Gen	10,476,165
	1822105	Unrcvrd Plt Dfctv Stm Gen Cont	(10,476,165)
	1822106	Unrecovered Plant - Urq Unit 3	557,754
	1822107	Unrecovered Plant - Mcmeekin	1,427,729
	1822108	Unrecovered Plant - Canadys 2	96,230,804
	1822200	Demolition - Parr Steam Plant	961,933
	1822201	Demolitn-contra-parr Steam Plt	(961,933)
	1822202	Demolitn-hagood Steam Plant	964,004
	1822203	Demolitn-contra-hagood Stm Plt	(964,004)
	1822208	Unrecovered Plant - Can Unit 1	12,125,813
	1823000	Reg Asset St Adit Elec	37,574,700
	1823001	Reg Asset St Adit Gas	1,637,500
	1823002	Reg Asset Fed Adit Elec	243,201,300
	1823003	Reg Asset Fed Adit Gas	10,529,100
	1823016	City Of Charleston - Franchise	32,012,572
	1823017	Charleston - Franchise-contra	(27,356,355)
	1823018	City Of Columbia - Franchise	50,841,005
	1823019	Columbia - Franchise - Contra	(41,148,154)
	1823026	Reg Asset Major Maint Accrual	13,173,376
	1823027	Reg Asset Pga Unbilled Contra	(1,777,084)
	1823031	Reg Asset Res Commodity Under	12,170,115
	1823032	Reg Asset Comm Commodity Under	(20,537,944)
	1823033	Reg Asset Ind Commodity Under	1,205,207
	1823034	Reg Asset Res Demand Under	21,949,573

		Balance @ 9/30/2017
1823035	Reg Asset Comm Demand Under	4,773,570
1823036	Reg Asset Ind Demand Under	1,151,799
1823051	Interest Income Mjm Psc Accrl	954,841
1823052	Reg Asset - Environmental Psi	264,602
1823055	Reg Asset Def Vcs Up-flow Mod	4,552,289
1823056	Reg Asst Recover Capacity Purc	826,333
1823062	Other Reg Asset - 150m Swap	24,451,628
1823065	Reg Asset-fukushima-vcs	4,211,659
1823066	Reg Asset - Defer Capacity Pur	2,134,511
1823069	Reg Asset-def Cap-2014-2016-so	2,624,177
1823070	Reg Asset-def Cap-2014-19 Colu	20,698,982
1823072	Reg Asset Nnd Carrying Costs	45,762,447
1823073	Reg Asset - Cip5	11,003,551
1823075	Reg Asset-cyber Security Compl	3,084,297
1823076	Reg Asset - Ubs #252	7,504,977
1823077	Reg Asset - Boa #249	7,631,063
1823078	Reg Asset-morgan Stanley #251	17,867,000
1823079	Reg Asset - Boa - Swap #250	6,910,758
1823080	Reg Asset - Us Bank Swap #254	6,811,303
1823081	Reg Asset - Union Bank Swap #2	4,665,314
1823082	Reg Asset-morgan Stanley-reg A	3,818,510
1823083	Gas Wna Cap -winter 2015	1,766,584
1823084	Gas Wna Cap -winter 2016	1,455,666
1823085	Reg Asset-cyber Secur Depr Car	912,118
1823086	Reg Asset $75mm Due 6/1/64	21,267,586
1823087	Reg Asset $425mm Due 6/15/46	119,155,320
1823092	Gas Wna Cap- Winter 2017	1,437,141
1823095	Reg Asset Nnd 41/199 (pilot)	18,730,200
1823096	Reg Asset Nnd Acct Fees/intere	8,958,262
1823105	Reg Asset - Decom Aro	44,027,699
1823106	Def Aro Acretion And Arc Depr	341,369,990
1823107	Def Econ Grant - Dixie Narco	200,000
1823108	Def Econ Grant - Michelin	358,333
1823109	Def Econ Grant-bf Phase 1	425,000
1823110	Def Econ Grant-bf Phase 2	425,000
1823111	Def Econ Grant-bf Phase 3	2,096,667
1823112	R & D Grant - Clemson	3,025,000
1823113	Def Econ Grant - Michelin 2	236,264
1823114	Def Econ Grant - Nexans	175,000
1823115	Def Econ Grant - Koyo Corp	168,750
1823116	Def Econ Grant - Boeing/chas C	4,527,778
1823117	Def Econ Grant - Mercedes/chas	1,888,889
1823118	Def Econ Grant - Fairfield Meg	2,204,558
1823120	Def Econ Grant-kronotex	977,778
1823200	Reg Asset Dem Side Mgt Costs	1,220,327
1823205	Deferred Storm Damage Costs	22,200,018
1823220	Reg Asset Gwh Rebates	1,904,426
1823226	Reg Asset Gwh Rbt Rec Sonat	(190,700)
1823242	Reg Asset Gwh 2012	46,108
1823243	Reg Asset Gwh 2013	362,547
1823244	Reg Asset Gwh 2014	740,782
1823245	Reg Asset Gwh 2015	925,217
1823246	Reg Asset Gwh 2016	1,771,237
1823255	Res Water Heaters	2,788,787
1823256	Res Appliance Recycling	1,310,632
1823259	Res Limited Income	2,502,555
1823260	Dsm Admin	5,411,269
1823261	Res Benchmarking	3,363,256
1823262	Res In-home Display	1,315,466

		Balance @ 9/30/2017
1823263	Res Energy Check Up	4,062,626
1823264	Res Estar Light And Appliance	15,509,086
1823265	Res New Hvac And Duct Work	11,922,237
1823266	Res Existing Hvac - Tune-up	1,956,211
1823267	Res Energy Star New Homes	1,557,504
1823268	Res Home Perf Audit	3,613,364
1823271	C & I Energy Wise For Business	30,740,864
1823272	Com And Ind Custom	4,476,934
1823273	Small Business Direct Install	4,146,321
1823280	Res Dsm Accum Amort	(29,222,351)
1823281	Com Ind Dsm Accum Amort	(18,059,938)
1823282	Res Dsm Carrying Costs	9,873,764
1823283	Com Ind Dsm Carrying Costs	5,907,439
1823350	Reg Asset-t Lock 6 625 Due 2 1	(837,705)
1823351	Reg Asset-t-lock 6 80 Due 1 15	(137,485)
1823352	Reg Asset-t-lock 6 25 Due 7 1	(7,057,704)
1823353	Reg Asset 5 30 T Lock Due 5 15	8,537,174
1823354	Reg Asset T Lock 5 25 Due 11 1	357,222
1823355	Reg Asset-t Lock 5 25 Due 3 1	1,419,729
1823356	Reg Asset-swap 6 05 Due1 15 38	11,969,368
1823357	Reg Asset-lock 6 05 Due 1 15 2	(430,520)
1823358	Reg Asset - 150m Fmb	2,887,726
1823359	Reg Asset 125m Swap Boa	7,557,540
1823360	Reg Asset 125m Swap Wf	8,185,247
1823361	Reg Asset 100m Csfb	12,197,567
1823362	Reg Asset 75m Boa	23,106,828
1823363	Reg Asset 75m Wells Fargo	23,282,288
1823366	Reg Asset U S Bank #228	5,620,403
1823367	Reg Asset W/f #226	11,421,577
1823368	Reg Asset Jpm #220	5,700,105
1823369	Reg Asset Jpm #230	10,966,380
1823378	Reg Asset W/f #217	36,856,916
1823379	Reg Asset Ms #227	37,388,250
1823380	Reg Asset Boa #222	36,980,500
1823381	Reg Asset #234	4,737,185
1823382	Reg Asset - New Sifma	6,058,846
1823390	Reg Asset-$500mm Debt Due 6-1-	146,898,972
1823395	Reg Asset M Stanley #256	3,281,116
1823396	Reg Asset Wf #257	3,143,225
1823397	Reg Asset Boa #258	3,056,630
1823411	Reg Asset - Gas Sfas 158 Adj	28,204,995
1823412	Reg Asset Elec Sfas 158 Adj	198,525,482
1823414	Reg Asset - Elec Fas 87 Deferr	53,210,719
1823415	Reg Asset - Gas Fas 87 Deferra	9,594,477
1823504	Reg Asst Cust Aw Pro Vntg 2011	3,604
1823505	Reg Asset Cust Aw Pro Vntg 201	43,356
1823508	Reg Asst Cust Aw Pro Vntg 2015	10,417
1823601	Reg Asset-poll Cntrl-wms Scrbr	7,731,607
1823602	Reg Asset-poll Cntrl-wat Scrbr	24,359,501
1823700	Gas Pipeline Integrity	7,406,639
Environmental		**24,735,924**
1823401	Reg Asst Mgp Env Remd Cur Vntg	24,735,924
Prelim Survey & Investigation		**740,315**
1830000	Columbia Energy Center Acquisition Study	552,287
1830180	Fish Entrainment Studies	116,852
1830186	Psi Vcs1 Switchyard Add Capaci	2,137
1830187	Meeting St Replacement Sub Sit	3,496

		Balance @ 9/30/2017
	1830524 Calhoun/bull St Substation	65,543
Misc Deferred Debits		**4,681,349,389**
	1860000 Unrecovered V.C. Summer Unit 2 & 3 Costs	4,520,183,565
	1860006 Def Dr Inv Wo Prop Acct Dist	8,125
	1860007 Def Dr Blnkt Po Wo Prop Dist	9,211
	1860010 Misc Deferred Debits - Misc	165,115
	1860020 Ciac-cis Billing	(237,936)
	1860022 Def Dr Other Work In Prog	32,132,301
	1860023 Def Dr Telephone Pole Rent	1,647,658
	1860033 Treas A For Cust Acctg	(38,936)
	1860034 Cis System Balance	21
	1860067 Chas Garage Accrued Interest	1,590
	1860069 Def Debit Cble Pole Attach Ren	1,663,733
	1860081 Deferred Dr-jasper Ge Csa	681,312
	1860085 Def Dr Nu Inventory Wo	(68,593)
	1860096 Deferred Debit - Urquhart Ge C	303,414
	1860134 Def Dr 5yr Commitment Fees	2,971,340
	1860149 Sceg Workers Comp Reserve Def	308,398
	1860156 Def Dr-fees 3yr Agreement	25,612
	1860190 Plex Lease Buyout Cost	1,464,535
	1860191 N Chas Hotel Property Lease Bu	1,660,982
	1860195 N Chas Prop-knts Inn-lease B C	1,808,047
	1860200 Def Dr - Vcs Isfsi Maint	413,243
	1860201 Def Dr - Vcs Inv Obs	752,802
	1860202 Def Dr-vcs Wo Issuance	3,773,027
	1860306 Def Dr Ar Psa Opeb	11,281,862
	1860320 Fed Amended Rtn Receivable	70,282,000
	1860405 Ar Int Inc Amended Rtn	2,147,023
	1860505 Def Debit-ge Jasper $705k	15,369
	1860532 Ar Pension Psa	4,462,006
	1860533 Ar Pension Fas 158	19,458,330
	1860632 Ar Opeb Psa	4,074,233
Due from Affiliates		**412,999**
	1860950 Csv Due From Sh For Dir Endow	412,999
Loss on Reacquired Debt		**14,259,590**
	1890120 Unamrt Loss 8 7/8% Due 8/15/21	575,095
	1890125 Un Loss Reac Dbt Fairfldco1984	1,170,322
	1890126 Un Loss Reac Dbt Fairfield1986	20,750
	1890128 Unam Loss Reacq Debt 56910000	880,433
	1890132 Unam Loss 7 5/8 Due 4 1 2025	1,487,449
	1890133 Unam Loss 3 22 Due 10 18 21	237,192
	1890134 Unam Loss Reacq Debt 29150000	621,378
	1890173 Unam Loss 8 7/8% Due 8/15/21	2,641,674
	1890174 Unamort Loss Reacq Debt	2,375,446
	1890177 Unamort Loss Reacq Debt	3,601,610
	1890178 Unam Loss Reacq Dbt 50m Prf Tr	648,241
Accum Deferred Income Tax		**789,250,672**
	1900001 Adit Fed Nuc Fuel Amort	2,020,500
	1900002 Adit St Nuc Fuel Amort	303,900
	1900009 Adit Fed Elec Itc Fasb 109	10,647,400
	1900010 Adit Fed Gas Itc Fasb 109	739,700
	1900012 Adit St Elec Itc Fasb 109	1,601,100
	1900013 Adit St Gas Itc Fasb 109	111,200
	1900015 Adit Fed Elec Kerp	(202,500)
	1900016 Adit Fed Gas Kerp	(36,300)

		Balance @ 9/30/2017
1900018	Adit Fed Nonoper Kerp	237,300
1900019	Adit St Elec Kerp	(30,400)
1900020	Adit St Gas Kerp	(5,500)
1900022	Adit St Nonoper Kerp	35,700
1900023	Adit Fed Elec Erip	2,976,600
1900024	Adit Fed Gas Erip	488,600
1900026	Adit Fed Nonoper Erip	730,400
1900027	Adit St Elec Erip	447,700
1900028	Adit St Gas Erip	73,600
1900030	Adit St Nonoper Erip	109,800
1900031	Adit Fed Elec Bonus Plan	1,606,900
1900032	Adit Fed Gas Bonus Plan	3,739,900
1900034	Adit St Elec Bonus Plan	241,600
1900035	Adit St Gas Bonus Plan	562,500
1900037	Adit Fed Elec Epa Cleanup	203,400
1900038	Adit Fed Gas Epa Cleanup	(5,385,200)
1900041	Adit St Elec Epa Cleanup	30,600
1900042	Adit St Gas Epa Cleanup	(809,800)
1900045	Adit Fed Nuc Refuel	3,882,600
1900046	Adit St Nuc Refuel	583,800
1900047	Adit Fed Nuc Decom	31,145,892
1900048	Adit Fed Nuc Decom Oth Inc	37,239,815
1900049	Adit St Nuclear Decom	4,727,083
1900050	Adit St Nuc Decom Oth Inc	5,556,482
1900067	Adit Fed Elec Uncoll Accts	944,500
1900068	Adit Fed Gas Uncoll Accts	132,700
1900069	Adit St Elec Uncoll Accts	142,000
1900070	Adit St Gas Uncoll Accts	20,000
1900071	Adit Fed Elec Inj And Dam	2,308,000
1900072	Adit Fed Gas Inj And Dam	305,400
1900074	Adit St Elec Inj And Dam	347,000
1900075	Adit St Gas Inj And Dam	45,900
1900077	Adit Fed Elec Opeb	46,373,700
1900078	Adit Fed Gas Opeb	6,966,000
1900080	Adit St Elec Opeb	6,973,500
1900081	Adit St Gas Opeb	1,047,500
1900083	Adit Fed Nonop Opeb	460,500
1900084	Adit St Nonop Opeb	69,400
1900105	Adit Fed Elec Storm Dmg Accrls	(6,552,400)
1900106	Adit St Elec Storm Dmg Accrls	(985,400)
1900137	Adit Fed Elec Ltd	258,800
1900138	Adit Fed Gas Ltd	44,500
1900139	Adit St Elec Ltd	38,800
1900140	Adit St Gas Ltd	6,700
1900141	Adit Fed Nonoper Ltd	6,400
1900142	Adit St Nonoper Ltd	1,000
1900143	Adit Fed Elec Accrued Vacation	1,428,000
1900144	Adit Fed Gas Accrued Vacation	256,100
1900146	Adit St Elec Accrued Vacation	214,700
1900147	Adit St Gas Accrued Vacation	38,600
1900161	Adit Fed - Directors Endowment	1,082,200
1900162	Adit St - Directors Endowment	162,700
1900163	Adit St Elec Major Maint	(557,900)
1900165	Adit Fed Elec Major Maint	(3,709,800)
1900195	Federal Non Operating-serp	35,700
1900196	State Non Operating-serp	5,400
1900197	Fed Non Oper Serp Interco	277,900
1900198	St Non Oper Serp Interco	41,800
1900222	Adit - Fed Gas Rec Line Pack	63,500

		Balance @ 9/30/2017
1900223	Adit - St Gas Rec Line Pack	9,600
1900227	Adit - Fed Gas Rec Wsh Gas	52,200
1900228	Adit - St Gas Rec Wsh Gas	7,800
1900240	Adit - Fed Gas 263a	535,000
1900241	Adit - St Gas 263a	80,500
1900267	Adit Fed Elec Long Term Pledge	88,100
1900269	Adit St Elec Long Term Pledges	13,300
1900274	Adit Fed Reg Asset Enviromenta	(111,600)
1900277	Adit St Reg Asset Enviromental	(16,800)
1900278	Adit Fed Elec Aro Liability	95,160,000
1900279	Adit St Elec Aro Liability	14,309,500
1900280	Adit Fed Gas Aro Liability	9,188,100
1900281	Adit St Gas Aro Liability	1,381,700
1900301	St Elec Opeb Fas 158	1,063,100
1900302	St Gas Opeb Fas 158	155,300
1900306	Fed Elec Opeb Fas 158	7,069,900
1900307	Fed Gas Opeb Fas 158	1,032,300
1900408	Adit Fed Toshiba Settlement	364,164,100
1900409	Adit St Toshiba Settlement	54,761,500
1900410	Adit Fed Impairment Charge	68,185,800
1900411	Adit St Impairment Charge	10,253,500

Deferred Credits		**(3,890,012,660)**
Due to Affiliates		**(12,819,131)**
2530050	Apay Directors Endowment	(3,302,891)
2530712	Def Cr Apay Lt Disabil Sfas112	(1,085,805)
2530912	Def Cr Apay-sh-erip	(8,430,434)
Other Deferred Credits		**(55,458,051)**
2530000	Misc Deferred Credits	(3,101,726)
2530005	Def Cr Mgp Enviro Cleanup	(9,877,998)
2530008	Def Cr Oth Enviro Cleanup	(600,000)
2530027	Def Cr Unearn Int Third	(284,675)
2530038	Chas Garage Pre-pymt	(102,419)
2530048	Oth Def Cr Apog Llc-psa	(113)
2530053	Santee River Basin Accord	(959,384)
2530065	City Of Columbia Nssf	(5,854,308)
2530070	Intercon Stdy Dep 3rd Pty	(2,712,184)
2530079	Def Cr Long Term Pledges	(265,000)
2530100	Def Cr 16 Off Lt Bonus	(660,885)
2530101	Def Cr 16 Off Rest Stock Lt Bo	(401,777)
2530103	Bonus Payroll Taxes	(70,725)
2530117	Def Cr 2017 Officer Long Term	(340,262)
2530118	Def Cr 2017 Off Restricted Stk	(168,672)
2530159	Ap Fin 48 Int Exp	(8,581,700)
2530196	Def Cr Unearn Int Third	(5,435)
2530198	Ingleside Future Ciac Obligati	(1,559,702)
2530199	Cainhoy Future Ciac Obligation	(15,764,543)
2530200	Def Cr Cbl Pole Attach Rentals	(2,230,276)
2530211	Internal Wtr Htr Deferred Int	(183,161)
2530223	Def Cr Srs Substation Markup	(1,733,107)
Other Regulatory Liabilities		**(1,257,486,139)**
2540000	Reg Liab Fuel Clause Ovrcllctn	15,174,996
2540000	DER Overcollection	(2,163,793)
2540011	Oth Reg Liab Nuclear Refueling	(2,850,791)
2540013	Reg Liab Elec - Unbilled Fuel	(18,179,011)
2540028	Other Reg Liab-150m Fss	(19,679,972)

		Balance @ 9/30/2017
2540030	Other Reg And Liab 150m Lock	(2,114,866)
2540041	Reg Liab Reagent Over Collect	(1,410,591)
2540042	Other Reg Liability-35 Fss	(4,871,755)
2540044	Other Reg Liability 80m Swap U	(3,599,092)
2540045	Other Reg Liability 80m Swap M	(4,112,387)
2540046	Other Reg Liability 90m Swap C	(3,464,493)
2540047	Other Reg Liab - 90m Swap Ubs	(14,437,015)
2540048	Other Reg Liab - 80m Swap Wf	(350,883)
2540049	Other Reg Liab - 80m Swap Boa	(12,908,436)
2540050	Other Reg Liab - 90m Swap Mizu	(499,595)
2540051	Other Reg Liab - 80m Swap Ms	(12,614,555)
2540052	Other Reg Liab - 80m Swap Db	(305,977)
2540080	Equity Dsm Residential Carry C	(2,531,108)
2540081	Equity Dsm Com/ind Carry Costs	(1,410,693)
2540083	Reg Liab Swap#260 Mub	(4,882,039)
2540084	Reg Liab Swap#261 Tdb	(9,592,234)
2540085	Reg Liab Swap#262 Rbc	(19,298,791)
2540086	Reg Liab Swap#263 Credit Suiss	(19,866,892)
2540087	Reg Liab Swap#265 Morgan Stanl	(1,231,547)
2540088	Reg Liab Swap #266 Boa	(716,722)
2540089	Winnsboro Fuel Overcollected	(62,850)
2540090	Orangeburg Fuel Over Collected	(1,023,966)
2540098	Reg Liab - Enviromental Remedi	(53,153)
2540100	Reg Liab So2 Arp	(707)
2540101	Reg Liab S02 Csapr	(322)
2540140	Rg Liab-toshiba Settl Proceeds	(1,095,230,291)
2540151	Reg Liab Nox Ozone Csapr	(657)
2540161	Reg Liab Nox Annual Csapr	(377)
2540162	Elec Pension Rider Overrcvry	(96,173)
2540202	Reg Liab Itc Federal Elec	(10,647,400)
2540203	Reg Liab Itc Fed Gas	(739,700)
2540205	Reg Liab Itc State Electric	(1,601,100)
2540206	Reg Liab Itc State Gas	(111,200)
Accum Def Inc Tax Cr		**(21,147,400)**
2550003	Acc Def Itc Fed Elec	(6,289,000)
2550004	Acc Def Itc Fed Nucl	(13,484,700)
2550005	Acc Def Itc Fed Gas	(1,373,700)
Accum Def Inc Taxes-Liability		**(2,543,101,939)**
2810000	Adit Accel Amort Property	(10,465,500)
2810001	Accel Amort State	(1,573,800)
2820001	Adit Fed Elec Liberal Depr	(1,220,856,100)
2820003	Adit Fed Gas Liberal Depr	(150,134,400)
2820004	Adit Fed Btl Depr	(6,629,400)
2820005	Adit St Elec Liberal Depr	(145,270,400)
2820007	Adit St Gas Liberal Depr	(13,620,600)
2820008	Adit St Btl Depr	(996,500)
2820011	Adit Fed Elec Intangibles	(3,828,600)
2820014	Adit St Elec Intangibles	(576,000)
2820017	Adit Fed Elec Plt Fasb 109	(243,201,300)
2820018	Adit Fed Gas Plt Fasb 109	(10,529,100)
2820020	Adit St Elec Plt Fasb 109	(37,574,700)
2820021	Adit St Gas Plt Fasb 109	(1,637,500)
2820029	Adit Fed Elec Basis Dif	8,570,300
2820030	Adit Fed New Nucl Int Dif	266,511,500
2820031	Adit Fed Gas Basis Dif	340,400
2820033	Adit St Elec Basis Dif	1,288,800
2820034	Adit St New Nucl Int Dif	40,073,900

		Balance @ 9/30/2017
2820035	Adit St Gas Basis Dif	51,200
2820038	Adit Fed Int Emis Allowances	(215,600)
2820039	Adit St Emis Allowances	(32,500)
2820070	Adit Fed Reg Pollution Control	(2,288,100)
2820071	Adit St Reg Pollution Control	(344,100)
2820072	Adit Fed Wateree Scrubber	(8,717,500)
2820073	Adit St Wateree Scrubber	(1,310,900)
2820076	Adit Fed Net Elec Arc	12,012,800
2820077	Adit St Net Elec Arc	1,806,400
2820078	Adit Fed Net Elec Nucl Arc	(2,841,279)
2820079	Adit St Net Elec Nucl Arc	(427,260)
2820080	Adit Fed Net Gas Arc	(2,855,200)
2820081	Adit St Net Gas Arc	(429,400)
2820082	Adit Fed No2 Emission Allowanc	1,200
2820083	Adit St No2 Emission Allowance	200
2820084	Adit Fed Nnd Basis Diff (orig	(84,878,900)
2820085	Adit St Nnd Basis Diff (orig C	(12,763,700)
2820086	Adit Fed Nnd Rate Base (orig C	37,171,300
2820087	Adit St Nnd Rate Base (orig Cl	5,589,700
2820088	Adit Fed Nnd 174 Rate Base (or	(6,312,400)
2820089	Adit St Nnd 174 Rate Base (ori	(949,400)
2820101	Adit Fed Nnd Basis Diff (pilot	(470,309,000)
2820102	Adit St Nnd Basis Diff (pilot)	(70,720,200)
2820146	Adit Fed Elec Res And Exp	(7,849,600)
2820147	Adit Fed Gas Res And Exp	(544,400)
2820148	Adit State Elec Res And Exp	(1,180,400)
2820149	Adit St Gas Res And Exp	(81,900)
2820150	Adit Fed Basis Old Nuc Amended	(3,899,000)
2820151	Adit St Basis Old Nuc Amended	(1,045,100)
2830017	Adit Fed Elec Fuel	3,247,900
2830018	Adit Fed Gas Fuel	(5,784,500)
2830019	Adit St Elec Fuel	488,400
2830020	Adit St Gas Fuel	(869,800)
2830029	Adit Fed Elec Dem Side Mgt	(19,827,200)
2830030	Adit St Elec Dem Side Mgt	(2,981,500)
2830031	Adit Fed Elec Ls Reacq Debt	(4,514,300)
2830032	Adit Fed Gas Ls Reacq Debt	(511,900)
2830033	Adit St Elec Ls Reacq Debt	(678,800)
2830034	Adit St Gas Ls Reacq Debt	(77,000)
2830039	Adit Fed Elec Pension Exp	(37,956,900)
2830040	Adit Fed Gas Pension Exp	(6,796,600)
2830042	Adit Fed Nonop Pension Exp	(43,814,100)
2830043	Adit St Elec Pension Exp	(5,707,800)
2830044	Adit St Gas Pension Exp	(1,022,000)
2830046	Adit St Nonop Pension Exp	(6,588,500)
2830084	Adit Fed Elec Prepayments	(22,383,600)
2830085	Adit Fed Gas Prepayments	(3,202,400)
2830086	Adit State Elec Prepayments	(3,366,000)
2830087	Adit State Gas Prepayments	(481,600)
2830099	Adit Fed Defer Capacity	(5,674,600)
2830118	Adit Fed Rec Cap Reg Asset	(348,600)
2830119	Adit St Rec Cap Reg Asset	(52,400)
2830123	Adit Fed Canadys Refined Prtsh	(206,800)
2830124	Adit St Canadys Refined Prtshp	(31,000)
2830129	Adit St Defer Capacity	(853,300)
2830130	Adit Fed Fukishima Reg Asset	(1,361,100)
2830131	Adit St Fukishima Reg Asset	(204,700)
2830132	Adit St Gas Wna Cap Reg Asset	(150,300)
2830133	Adit Fed Gas Wna Cap Reg Asset	(999,500)

		Balance @ 9/30/2017
2830136	Adit St Unrecovered Plant- Can	(5,417,800)
2830137	Adit Fed Unrecovered Plant- Ca	(36,028,600)
2830138	Adit-fed Brandon Shores Llc	(69,000)
2830139	Adit St Brandon Shores Llc	(10,300)
2830140	Adit Fed Louisa Refined Llc	(27,900)
2830141	Adit St Louisa Refined Llc	(4,100)
2830142	Adit Fed Grants	(864,500)
2830143	Adit St Grants	(130,000)
2830144	Adit Fed Urquhart Unit 3	(185,500)
2830145	Adit Fed Mcmeekin	(474,700)
2830146	Adit Fed Srfi Llc	173,900
2830147	Adit St Urquhart Unit 3	(27,900)
2830148	Adit St Mcmeekin	(71,400)
2830149	Adit St Srfi Llc	26,200
2830153	Adit Fed Btl Fin 48 Int/exp	(272,400)
2830154	Adit St Btl Fin 48 Int Inc/exp	(40,800)
2830157	Adit Fed Elec Pilot Fin48 Int	2,411,800
2830158	Adit St Elec Pilot Fin48 Int E	362,700
2830166	Adit Fed Pilot Fasb 109	(6,227,800)
2830167	Adit St Pilot Fasb 109	(936,500)
2830168	Adit Fed Pilot Interest/prof F	(2,975,900)
2830169	Adit St Pilot Interest/prof Fe	(447,600)
2830171	Adit St Reg Cust Aw Prg Vint	(10,600)
2830172	Adit Fed Reg Cust Aw Prg Vint	(71,000)
2830173	Adit St Vcs Cost Under Rateor	(234,500)
2830174	Adit Fed Vcs Cost Under Rateor	(1,559,500)
2830175	Adit Fed Aro Elec Reg Asset	(107,172,600)
2830176	Adit St Aro Elec Reg Asset	(16,116,100)
2830177	Adit Fed Aro Gas Reg Asset	(6,332,900)
2830178	Adit St Aro Gas Reg Asset	(952,300)
2830179	Adit Fed Nnd Carrying Cost-reg	(15,216,000)
2830182	Adit Fed Apog Llc	(55,900)
2830183	Adit St Apog Llc	(36,100)
2830184	Adit St Nnd Carrying Cost-reg	(2,288,100)
2830189	Adit Fed Elec Cybersecurity	(3,550,600)
2830191	St Elec Serp Reg Rec	(98,700)
2830192	St Gas Serp Reg Rec	(12,000)
2830193	Fed Elec Serp Reg Rec	(656,700)
2830194	Fed Gas Serp Reg Rec	(80,500)
2830196	St Elec Serp Fas 158	98,700
2830197	St Gas Serp Fas 158	12,000
2830198	Fed Elec Serp Fas 158	656,700
2830199	Fed Gas Serp Fas 158	80,500
2830201	St Elec Pension Reg Rec	(8,764,400)
2830202	St Gas Pension Reg Rec	(1,242,800)
2830204	St Elec Pension Fas 158	8,764,400
2830205	St Gas Pension Fas 158	1,242,800
2830206	Fed Elec Pension Reg Rec	(58,283,200)
2830207	Fed Gas Pension Reg Rec	(8,265,400)
2830208	Fed Elec Pension Fas 158	58,283,200
2830209	Fed Gas Pension Fas 158	8,265,400
2830210	Adit Fed Elec Net Metering	343,200
2830211	Adit St Elec Net Metering	51,500
2830212	Adit St Gas Pipeline Integrity	(297,900)
2830213	Adit Fed Gas Pipeline Integrit	(1,980,700)
2830214	Adit St Elec Cybersecurity	(534,000)
2830301	St Elec Opeb Reg Rec	(1,063,100)
2830302	St Gas Opeb Reg Rec	(155,300)
2830306	Fed Elec Opeb Reg Rec	(7,069,900)

		Balance @ 9/30/2017
2830307	Fed Gas Opeb Reg Rec	(1,032,300)
2830310	Adit Fed Brunner Island Llc	(301,300)
2830311	Adit St Brunner Island Llc	(45,300)

South Carolina Electric & Gas Company
Office of Regulatory Staff's Continuing
Audit Information Request
Docket No. 2017-207-E (2nd Continuing AIR)
Docket No. 2017-305-E (1st Continuing AIR)
Docket No. 2017-370-E (1st Continuing AIR)
Response 1-61

Regulatory Assets	Utility Purpose	Balance @ 9/30/2017	Current Balance @ 12/31/2017
Accumulated Deferred Income Taxes	Accumulated Deferred Income Taxes contained within regulatory assets represent deferred tax liabilities that arise from utility operations that have not been included in customer rates. A substantial portion of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years.	$ 292,942,600	$ 26,502,000
Columbia & Charleston Franchise	Unamortized balances associated with SCE&G's investment in the 30 year electric and gas franchise agreements with the Cities of Columbia and Charleston, SC	14,349,069	13,303,261
Gas Water Heater Rebate Program (2011-2021)	Unamortized balance of expenditures associated with the Gas Water Heater Rebate Program	5,559,367	5,853,728
Decommissioning Asset Ret. Obligation	Deferred Asset Retirement Obligation (ARO) represents the legal obligation and related funding associated with the decommissioning and dismantlement of VCS Unit 1.	44,036,214	68,427,634
MGP Environmental Remediation	Costs associated with the assessment and cleanup of formerly owned SCE&G manufactured gas plant sites	24,735,928	24,644,099
Deferred ARO Accretion & Depreciation Costs	Accretion and depreciation costs related to conditional AROs for generation, transmission and distribution properties, including gas pipelines.	341,369,990	326,295,964
Interest Rate Derivatives	Deferred losses associated with the effective portions of changes in fair value and payments made upon settlement of interest rate deriviatives entered into by the Company to mitigate exposure to interest rate volatility.	623,230,835	446,412,254
Deferred Employee Benefit Plan Costs-Gas (ASC 715)	Unamortized actuarial losses and prior service costs and transition obligation, as of the balance sheet date, related to SCE&G's post retirement benefit plans assigned to it's gas operations	28,204,995	30,103,557
Deferred Employee Benefit Plan Costs-Elec (ASC 715)	Unamortized actuarial losses and prior service costs and transition obligation, as of the balance sheet date, related to SCE&G's post retirement benefit plans assigned to it's electric operations	198,525,482	179,509,540
Gas Customer Awareness Program (11/2011-10/2018)	Unamortized balance associated with gas customer awareness advertising programs	57,376	33,350
Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	Unamortized balance associated with reconfiguration of the V.C. Summer Nuclear Station fuel rod coolant flow to minimize the effects of baffle jetting	4,552,289	4,506,335
Deferred Capacity Charges (7/2010-7/2020)	Unamortized balance associated with deferral of certain electric capacity purchases	826,334	752,334
Deferred Capacity Charges	Unamortized balance associated with deferral of certain electric capacity purchases	2,134,511	2,134,511
Electric Demand Side Management	Deferral of expenditures associated with Demand Side Management Programs	64,396,605	66,246,822
Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	Unamortized balance associated with SCE&G's purchased power costs incurred as a result of the installation of a flue gas desulfurization unit (scrubber) at the A.M. Williams Generating Station.	7,731,604	7,660,939
Economic Development Grants (10/2009-11/2031)	Unamortized balance associated with grants made to support economic development within SCE&G's territory and the State of South Carolina	13,684,011	13,324,179
Major Maintenance Accrual and Interest	The major maintenance accrual as approved by the SCPSC is designed to levelized major maintenance costs associated with fossil fuel turbine/generation equipment. This amount represents undercollected costs incurred in excess of the levelized annual amount of $18.4 million. Includes carrying cost on undercollected balance.	14,119,706	19,121,104
Deferred Pension Cost - Gas (11/2013-1/2027)	Deferral of pension costs assigned to gas operations	9,594,474	9,337,097
Deferred Pension Cost - Electric (1/2013-12/2042)	Deferral of pension costs assigned to electric operations	53,210,715	52,713,756
Environmental Compliance Studies (7/2010 - 7/2020)	Unamortized balance associated with the deferral of costs to comply with environmental regulations	264,605	240,906

Deferred Pollution Control Costs - Wateree (1/2013-9/2040)	Unamortized balance associated with SCE&G's deferred operation and maintenance costs incurred as a result of the installation of a scrubber at the Wateree Generating Station.	24,359,501	24,094,016
Research and Development Grant (1/2013-12/2047)	Unamortized balance associated with research and development grants to Clemson University in support of the SCE&G Energy Innovations Center located in North Charleston South Carolina and in support of the Clemson University Hardware-in-the-loop grid simulator facility	3,025,000	3,000,000
Amount Undercollected - Gas Cost Adjustment	Undercollected balance of gas costs under SCE&G's purchased gas adjustment	18,935,237	10,526,844
Gas WNA Cap - Winter 2015 (11/2016 - 10/2021)	In periods of extremely mild winter weather, SCE&G's gas weather normalization adjustment limits the increase to customer bills in the month the mild weather is experienced. SCE&G defers this amount for future RSA recovery. This balance represents, the unamortized balance deferred for recovery for vintage year 2015	1,766,585	1,658,427
Gas WNA Cap - Winter 2016 (11/2017 - 10/2022)	In periods of extremely mild winter weather, SCE&G's gas weather normalization adjustment limits the increase to customer bills in the month the mild weather is experienced. SCE&G defers this amount for future RSA recovery. This balance represents, the unamortized balance deferred for recovery for vintage year 2016	1,455,666	1,407,144
Gas WNA Cap - Winter 2017	In periods of extremely mild winter weather, SCE&G's gas weather normalization adjustment limits the increase to customer bills in the month the mild weather is experienced. SCE&G defers this amount for future RSA recovery. This balance represents, the unamortized balance deferred for recovery for vintage year 2017	1,437,141	1,437,141
Fukushima Compliance Costs	Deferral and amortization of costs associated with complying with certain regulations promulgated by the Nuclear Regulatory Commission as a result of the Fukushima incident	4,211,660	4,242,683
Deferred Long-Term Capacity Contract	Deferral and amortization of deferred capacity aquired as a result of the retirement of Canady's Station	23,323,160	26,019,928
Carrying Costs Accrual	Carrying costs accrued on the balance of nuclear project deferred tax assets held outside of rate base	45,762,447	-
Cyber Compliance Costs	Deferred costs incurred in complying with regulations promulgated by the Nuclear Regulatory Commission for Cyber Security	3,996,416	4,580,257
CIPv5 Compliance Costs	Deferral of depreciation, amortization, and incremental operation & maintenance expesnses incurred in complying with existing and future Critical Infrastructure Protection Reliability Standards promulgated by the FERC. Also includes carrying costs on unamortized balance	11,003,549	12,248,142
Gas Pipeline Integrity Costs	Deferred costs incurred as result of complying with certain regulations promulgated by the US Dept of Transportation Pipeline and Hazardous Materials Safety Administration	7,406,640	7,937,766
Deferred Costs Related to Certain Claims for Tax Deductions and Credits	Estimated amounts of deferred domestic production activites deduction foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest and other costs arising from these claims.	27,688,462	-
Deferred Storm Damage Costs	Deferral of costs incurred to restorse service and repair system as a result of storms	22,200,019	23,793,594
Amt. Undercollected - Elec Fuel Adjustment Clause	Undercollected balance of electric fuel costs in accordance with SCE&G's fuel adjustemnt clause		395,241
Undercollected Electric Pension Expense	Undercollected pension rider recoveries	-	578,227
Excess Deferred Tax Assets	Represents excess deferred income taxes arising from the remeasurement of net operation loss deferred income taxes upon the enactment of the Tax Cuts and Jobs Act in 2017	-	341,359,200
		$ 1,940,098,193	$ 1,760,401,980

Regulatory Liabilities	Utility Purpose	Balance @ 9/30/2017	Balance @ 12/31/2017
Accumulated Deferred Income Tax Credits	Deferred income taxes arising from investment tax credits; offset by deferred income taxes that arise from utility operations that have not been included in customer rates	$ 13,099,400	$ 7,213,600
Nuclear Refueling Accrual	V.C. Summer Unit 1 refueling outage costs are levelized over a 5 outage cycle. This amount represents levelized accrued costs in excess of the actual amount incurred as of the balance sheet date	2,850,791	7,092,979
NOX Emission Allowance Proceeds	Deferral of amounts collected from sale of allowances to offset future purchases of allowances.	1,035	1,035

Interest Rate Derivatives (3/2009-6/2043)	Deferred gains associated with the effective portions of changes in fair value and payments received upon settlement of interest rate deriviatives entered into by the Company to mitigate exposure to interest rate volatility.	134,547,247	130,598,948
Demand Side Management Carrying Costs	Prior SCPSC orders allowed SCE&G to recognize carrying costs on its deferred demand side management costs at its weighted average cost of capital which included an equity component. In accordance with generally accepted accounting principles, the Company has deferred this equity carrying costs as a regulatory liability and is amortizing this balance as the equity carrying costs is recovered through rates.	3,941,801	3,716,468
SO2 Emission Allowance Proceeds	Deferral of amounts collected from sale of allowances to offset future purchases of allowances.	1,028	1,028
Wholesale Fuel Overcollection	Overcollection of wholesale electric fuel costs	1,086,813	1,523,758
Amt. Overcollected - Elec Fuel Adjustment Clause	Overcollected balance of electric fuel costs in accordance with SCE&G's fuel adjustemnt clause	4,414,612	0
Overcollected Electric Pension Expense	Overcollected pension rider recoveries	96,174	0
Overcollected DER and NET Metering Costs	The Company is allowed to defer and recover through specific riders costs associated with Distributed Energy Resource (DER) programs. This amount respresents the overcollected DER costs as of the balance sheet date.	2,163,793	3,281,137
Environmental Remediation Costs	The Company is allowed a levelized accrual for certain electric environmental remediation costs and this amount represents the levelized accrued amounts in excess of actual costs incurred as of the balance sheet date	53,153	113,153
Monetization of Toshiba Settlement	Settlement proceeds received upon the monetization of the Toshiba Settlement	1,095,230,292	1,095,230,292
Excess Deferred Tax Liabilities	Represents excess deferred income taxes arising from the remeasurement of deferred income taxes upon the enactment of the Tax Cuts and Jobs Act in 2017	0	1,237,304,200
		$ 1,257,486,139	$ 2,486,076,598

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-64 c.

SCEG STATE INCOME TAX ACCRUAL
YEAR TO DATE SEPTEMBER 2017

	ELECTRIC	GAS	ST TOTAL
OPERATING REVENUES	2,626,725,028	400,027,912	3,026,752,940
			-
OPER & MAINTENANCE	1,247,603,874	275,860,649	1,523,464,523
DEPRECIATION & AMORT	260,128,548	29,630,524	289,759,072
AMORTIZATION OF CANADYS	13,878,217	-	13,878,217
TAXES OTHER THAN INCOME	210,682,693	28,272,711	238,955,404
INTEREST EXPENSE	246,416,868	21,703,902	268,120,771
TOTAL EXPENSE	1,978,710,200	355,467,787	2,334,177,987
INCOME BEFORE INC TAXES	648,014,828	44,560,125	692,574,953
ADJTS FOR INC TAXES: FAV/(UNF): Remove book CR/(DR)			
AFUDC - DEBT PER INCOME STATEMENT - NUCLEAR	13,361,273	-	13,361,273
ESTIMATED TAX OVERHEAD FOR AFUDC - NEW NUCLEAR	(220,198,858)	-	(220,198,858)
BOOK DEPR CHGD OPER	(1,200,174)	(133,353)	(1,333,527)
BOOK DEPRECIATION & AMORT	(266,661,579)	(28,547,574)	(295,209,153)
BOOK EXP NUCL FUEL	(44,981,358)	-	(44,981,358)
REMOVAL COST - PRE-81	10,846,413	1,274,746	12,121,159
TAX DEPR NUCL FUEL	42,668,433	-	42,668,433
TAX DEPRECIATION	957,463,323	49,916,780	1,007,380,103
CYBERSECURITY	7,317,071	-	7,317,071
DEFERRED FUEL	57,125,936	4,719,469	61,845,405
EARLY RETIREMENT	1,558,958	275,110	1,834,068
ELEC DEMAND SIDE MGT	(519,610)	-	(519,610)
ENVIRONMENTAL CLEAN UP	(2,376)	(796,615)	(798,991)
FIN48	(387,397,777)	-	(387,397,777)
REG ASSET - FIN48 INTEREST/PROFESSIONAL FEES (PILOT)	3,564,437	-	3,564,437
GAS WNA CAP	-	1,811,353	1,811,353
GAS PIPELINE INTEGRITY	-	2,233,149	2,233,149
GRANTS	400,000	-	400,000
INJURIES AND DAMAGES	(2,372,195)	(132,246)	(2,504,442)
INVENTORY CAP SECTION 263A	-	357,390	357,390
JAD TERMINATION	(1,200,000)	-	(1,200,000)
LONG TERM DISABILITY	797,117	-	797,117
MAJOR MAINTENANCE	5,521,170	-	5,521,170
MEALS	(752,250)	(124,250)	(876,500)
NET METERING	(1,757,750)	-	(1,757,750)
NON TAXABLE REVENUE	41,039,970	258,074	41,298,044
NUCLEAR DECOMMISSIONING - TEMP	(3,224,921)	-	(3,224,921)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
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DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-64 c.

SCEG STATE INCOME TAX ACCRUAL
YEAR TO DATE SEPTEMBER 2017

	ELECTRIC	GAS	ST TOTAL
NUCLEAR REFUELING	(15,580,797)	-	(15,580,797)
OFFICERS 162M LIMITATION	(1,802,983)	(159,087)	(1,962,070)
OTHER POST RETIRE BENEFITS - TEMP	(3,620,647)	-	(3,620,647)
PENSION EXPENSE	(895,217)	(457,654)	(1,352,871)
PREPAYMENT ACCELERATION	2,421,315	(1,203,557)	1,217,757
REACQUIRED DEBT ADJTS	(1,056,021)	(86,364)	(1,142,386)
REG ASSET CUST AW PRG VINT	-	(335,103)	(335,103)
REG ASSET DEFER CAPACITY	6,238,082	-	6,238,082
REG ASSET FUKISHIMA COMPLIANCE	427,884	-	427,884
REG ASSET RECOVERY CAPACITY	(296,000)	-	(296,000)
REGULATORY ASSET - ASSET ENVIRONMENTAL	(94,783)	-	(94,783)
REGULATORY ASSET - CANADYS	(8,598,476)	-	(8,598,476)
REGULATORY ASSET - CANADYS UNIT 2	(2,140,762)	-	(2,140,762)
REGULATORY ASSET - MCMEEKIN	1,005,199	-	1,005,199
REGULATORY ASSET - POLLUTION CONTROL	(1,344,598)	-	(1,344,598)
STORM DAMAGE BOOK ACCRUAL	23,607,305	-	23,607,305
TOSHIBA SETTLEMENT	(1,095,230,291)	-	(1,095,230,291)
UNCOLLECTIBLE ACCOUNTS	(275,701)	-	(275,701)
VACATION ACCRUAL	503,113	89,050	592,163
VCS COST	(183,816)	-	(183,816)
TOTAL ADJTS	(885,521,942)	28,959,317	(856,562,625)
TAXABLE INCOME	1,533,536,770	15,600,808	1,549,137,578
TAX AT STATUTORY RATE	76,676,800	780,000	77,456,800
JOBS TAX CREDIT	(1,925,000)	-	(1,925,000)
ST ITC	(3,560,600)	(414,300)	(3,974,900)
TAX ACCRUED FOR CURRENT YEAR	71,191,200	365,700	71,556,900
RETURN TO PROVISION ADJUSTMENT	(3,328)	(247,927)	(251,255)
RETURN TO PROVISION - SCFC	2,000	-	2,000
TOTAL TAX EXP ADJTS	(1,328)	(247,927)	(249,255)
TOTAL INC TAX RECORDED	71,189,832	117,773	71,307,605

South Carolina Electric & Gas Company
Net Income Per 1,000 kWh Sold
For The Years Ending December 31, Last Five Years and Twelve Months Ending September 30, 2017
Total Company

LINE NO.		2012	2013	2014	2015	2016	Twelve Months Ending Spetember 30, 2017
1.	**OPERATING INCOME**						
2.	Operating Revenues	102.64	108.86	112.68	110.63	111.60	116.07
3.	**OPERATING INCOME DEDUCTIONS**						
4.	Operating Expenses	53.61	54.49	56.27	49.48	46.87	49.48
5.	Maintenance Expenses	5.26	5.67	5.87	6.16	5.89	6.04
6.	Depreciation Expenses	9.88	11.32	10.43	9.53	9.73	10.30
7.	Amortization of Utility Plant Acquisition Adjustment	0.65	0.78	1.20	1.23	1.39	1.54
8.	Taxes other than Income Taxes	6.79	7.75	7.65	8.04	8.55	9.20
9.	Income Taxes – Federal	4.75	5.68	1.14	9.21	(6.18)	15.78
10.	Income Taxes – Other	0.44	0.91	(0.32)	1.38	(0.80)	2.46
11.	Provision for Deferred Income Taxes	1.83	0.87	7.43	(1.22)	17.04	(8.85)
12.	Investment Tax Credit	(0.62)	(0.10)	(0.10)	(0.06)	(0.05)	(0.06)
13.	**Total Utility Operating Expenses**	82.59	87.37	89.57	83.75	82.44	85.89
14.	**Net Utility Operating Income**	20.05	21.49	23.11	26.88	29.16	30.18
15.	**OTHER INCOME AND DEDUCTIONS**						
16.	**Other Income:**						
17.	Allowance for Funds Used During Construction	0.86	1.12	1.18	1.06	1.10	0.88
18.	Miscellaneous Non-Operating Income	(0.07)	2.35	2.96	0.81	0.74	1.44
19.	**Total Other Income**	0.79	3.47	4.14	1.87	1.84	2.32
20.	**Other Income Deductions:**						
21.	Miscellaneous Income Deductions	0.59	0.67	0.90	0.81	0.50	9.72
22.	Taxes Applicable to Other Income & Deductions:						
23.	Income Taxes and Investment Tax Credits	(0.47)	0.27	0.15	(0.24)	(0.34)	(2.68)
24.	Taxes Other Than Income Taxes	0.02	0.01	0.03	0.01	0.02	0.03

South Carolina Electric & Gas Company
Net Income Per 1,000 kWh Sold
For The Years Ending December 31, Last Five Years and Twelve Months Ending September 30, 2017
Total Company

Attachment C w.calc wp

LINE NO.		2012	2013	2014	2015	2016	Twelve Months Ending Spetember 30, 2017
25.	Total Taxes on Other Income & Deductions	(0.45)	0.28	0.18	(0.23)	(0.32)	(2.65)
26.	**Net Other Income and Deductions:**	0.65	2.52	3.06	1.29	1.66	(4.75)
27.	**INTEREST CHARGES**						
28.	Interest on Long-Term Debt	7.33	8.23	8.31	9.24	10.00	10.79
29.	Amortization of Debt Expense	0.14	0.16	0.17	0.15	0.14	0.12
30.	Other Interest Expense	(0.09)	(0.19)	(0.22)	(0.16)	(0.16)	(0.02)
31.	Total Interest Charges	7.38	8.20	8.26	9.23	9.98	10.89
32.	**NET INCOME / 1000 kWh SOLD**	13.32	15.81	17.91	18.94	20.84	14.54
		23,899,168	22,326,578	23,332,942	23,114,845	23,471,194	22,631,440

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	001006	60 Elec Overhead Distribution Line	Line Extn & Improvmt	open	1006	2/2/1989 0:00	4/18/2001 0:00	(15.43)	15.43	0.00
1 Electric	001013	190 ACCD Payroll. OH & Adjustments	Fleet A&E Overheads	open	3841	8/12/1997 0:00	12/31/1997 0:00	19,993.02		19,993.02
1 Electric	001017	190 ACCD Payroll. OH & Adjustments	Vcs Nuclear Adm & Eng Overheads	open	3843	6/10/1987 0:00	4/18/2001 0:00	21,259.78		21,259.78
1 Electric	001134	60 Elec Overhead Distribution Line	Unattended Storeroom - Johnston	open	3845	6/9/1987 0:00	4/18/2001 0:00	333.82		333.82
1 Electric	001154	60 Elec Overhead Distribution Line	Unattended Storeroom - Metro Columb	open	3845	6/9/1987 0:00	4/18/2001 0:00	(5,850.00)		(5,850.00)
1 Electric	001254	60 Elec Overhead Distribution Line	Truck Stock - Metro Columbia	open	3845	5/4/1995 0:00	4/18/2001 0:00	(1,721.48)		(1,721.48)
1 Electric	001268	60 Elec Overhead Distribution Line	Truck Stock - Beaufort	open	3845	5/4/1995 0:00	4/18/2001 0:00	(698.00)		(698.00)
1 Electric	001269	60 Elec Overhead Distribution Line	Truck Stock - Holly Hill	open	3845	5/4/1995 0:00	4/18/2001 0:00	(433.73)		(433.73)
1 Electric	001279	60 Elec Overhead Distribution Line	Truck Stock - Charleston Lights	open	3845	11/7/1997 0:00	4/18/2001 0:00	(360.40)		(360.40)
1 Electric	001282	60 Elec Overhead Distribution Line	Truck Stock - St George	open	3845	5/4/1995 0:00	4/18/2001 0:00	433.73		433.73
1 Electric	008011	190 ACCD Payroll. OH & Adjustments	RE 1018 Clearing Overhead	open	892-16-998	1/1/2001 0:00	1/1/2001 0:00	(46,668.64)		(46,668.64)
1 Electric	008014	190 ACCD Payroll. OH & Adjustments	IN 1018 Clearing Overhead	open	894-15-998	1/1/2001 0:00	1/1/2001 0:00	(28,914.07)		(28,914.07)
1 Electric	008015	190 ACCD Payroll. OH & Adjustments	FH 1018 Clearing Overhead	open	895-15-998	1/1/2001 0:00	1/1/2001 0:00	(7,860.53)		(7,860.53)
1 Electric	008021	190 ACCD Payroll. OH & Adjustments	RE-Workers Comp. & Gen. Liab. Clear	open	890-217-365	1/1/2001 0:00	1/1/2001 0:00	(445,172.53)		(445,172.53)
1 Electric	008023	190 ACCD Payroll. OH & Adjustments	FH-Workers Comp. & Gen. Liab. Clear	open	890-218-856	1/1/2001 0:00	1/1/2001 0:00	(21,417.80)		(21,417.80)
1 Electric	105043	10 Steam Production	URQ Wastewater System	open	5766	4/1/2014 0:00	12/31/2018 0:00	309,372.99		309,372.99
1 Electric	105192	10 Steam Production	WAT Waste Water Pond	in service	9310	1/7/2015 0:00	1/31/2018 0:00	4,031,572.88		4,031,572.88
1 Electric	105252	10 Steam Production	WAT Limestone Ball Mill	in service	11235	3/23/2015 0:00	1/31/2018 0:00	9,593,209.68		9,593,209.68
1 Electric	105254	10 Steam Production	COP Dual Fuel Firing Systems	completed	113-7-115	4/1/2015 0:00	12/31/2017 0:00	2,969,641.25		2,969,641.25
1 Electric	105372	10 Steam Production	COP SCR Catalyst	open	6392	9/16/2015 0:00	12/31/2017 0:00	1,294,673.11		1,294,673.11
1 Electric	105379	10 Steam Production	WAT Spare ESS Transformer	in service	116-181-625	9/22/2015 0:00	1/31/2018 0:00	1,359,337.99		1,359,337.99
1 Electric	105434	10 Steam Production	MC1 HP/IP Turbine Buckets	in service	115-227-623	6/1/2016 0:00	8/31/2017 0:00	564,113.77		564,113.77
1 Electric	105462	10 Steam Production	WAT Effluent Limit system	open	4872	2/3/2016 0:00	12/31/2018 0:00	171,535.82		171,535.82
1 Electric	105472	10 Steam Production	WA1 480v MCC & C.H. 4160v SWGR	open	116-270-625	3/1/2016 0:00	12/31/2018 0:00	2,841,100.13		2,841,100.13
1 Electric	105474	10 Steam Production	WAT Digital Fault Recorder	in service	117-753-625	3/1/2016 0:00	12/31/2018 0:00	35,297.88		35,297.88
1 Electric	105490	10 Steam Production	FH$ UR3 4160v Breakers	in service	10512	2/29/2016 0:00	12/31/2017 0:00	295,793.88		295,793.88
1 Electric	105494	10 Steam Production	COP Digital Fault Recorder	open	117-804-115	3/2/2016 0:00	12/30/2017 0:00	39,393.06		39,393.06
1 Electric	105517	10 Steam Production	MC1 Gen Exciter Volt Regulator	in service	8867	6/1/2016 0:00	12/31/2017 0:00	378,590.00		378,590.00
1 Electric	105523	10 Steam Production	UR3 4160V Switchgear Relays	in service	10512	2/29/2016 0:00	12/31/2017 0:00	262,319.75		262,319.75
1 Electric	105532	10 Steam Production	MC1 Gas Ignitors	open	8871	8/1/2016 0:00	7/31/2020 0:00	195,304.34		195,304.34
1 Electric	105534	10 Steam Production	MC2 Gas Ignitors	open	8872	8/1/2016 0:00	12/31/2020 0:00	147,561.31		147,561.31
1 Electric	105538	10 Steam Production	MC1 Gas Pressure Control Valves	open	8871	7/1/2016 0:00	7/31/2020 0:00	27,115.40		27,115.40
1 Electric	105539	10 Steam Production	MC2 Gas Pressure Control Valves	open	8872	7/1/2016 0:00	1/31/2020 0:00	22,450.88		22,450.88
1 Electric	105540	10 Steam Production	MC1 ID Fan VFD Controllers	in service	5865	7/1/2016 0:00	12/31/2017 0:00	421,830.70		421,830.70
1 Electric	105542	10 Steam Production	MC2 ID Fan VFD Controllers	in service	5866	7/1/2016 0:00	12/31/2017 0:00	311,046.01		311,046.01
1 Electric	105575	10 Steam Production	UR3 Generator Relay	in service	11051	8/1/2016 0:00	12/31/2017 0:00	23,699.66		23,699.66
1 Electric	105596	10 Steam Production	URQ Circuit Breaker Panels-2017	open	10517	1/1/2017 0:00	8/31/2018 0:00	212,884.12		212,884.12
1 Electric	105616	10 Steam Production	UR3 Governor Controls 2017	in service	8852	1/1/2017 0:00	12/31/2017 0:00	603,168.35		603,168.35
1 Electric	105627	10 Steam Production	WAT Excitation Control HMI	in service	6113	10/1/2016 0:00	1/31/2018 0:00	119,913.20		119,913.20
1 Electric	105635	10 Steam Production	URQ Water Treatment 2017	open	117-847-619	1/1/2017 0:00	12/31/2017 0:00	373,051.85		373,051.85
1 Electric	105664	10 Steam Production	UR2 Sta Svc Transformer Power Cable	open	11545	12/19/2016 0:00	5/31/2018 0:00	18,963.45		18,963.45
1 Electric	105669	10 Steam Production	FH$ MCM Plant Valves 2017	in service	117-624-623	1/1/2017 0:00	12/31/2017 0:00	10,305.75		10,305.75
1 Electric	105670	10 Steam Production	FH$ MCM Plant Instrumentation 2017	in service	117-746-623	1/1/2017 0:00	12/31/2017 0:00	23,064.16		23,064.16
1 Electric	105671	10 Steam Production	MCM Plant Air Conditioners 2017	in service	112-400-623	1/1/2017 0:00	12/31/2017 0:00	53,947.32		53,947.32
1 Electric	105672	10 Steam Production	MCM Pumps and Piping 2017	in service	8294	1/1/2017 0:00	12/31/2017 0:00	9,075.95		9,075.95
1 Electric	105685	10 Steam Production	URQ Misc. Pumps 2017	in service	117-851-619	1/1/2017 0:00	12/31/2017 0:00	36,785.01		36,785.01
1 Electric	105686	10 Steam Production	COP Pumps 2017	completed	117-719-115	1/1/2017 0:00	12/31/2017 0:00	2,580.40		2,580.40
1 Electric	105687	10 Steam Production	COP Motors 2017	in service	117-911-115	1/1/2017 0:00	3/31/2018 0:00	94,527.38		94,527.38
1 Electric	105688	10 Steam Production	COP Valves 2017	completed	117-806-115	1/1/2017 0:00	12/31/2017 0:00	97,606.13		97,606.13
1 Electric	105689	10 Steam Production	COP Instrumentation 2017	completed	117-804-115	1/1/2017 0:00	12/31/2017 0:00	108,256.10		108,256.10
1 Electric	105690	10 Steam Production	COP Cooling Tower Gearbox	completed	119-423-115	1/1/2017 0:00	12/31/2017 0:00	100,599.66		100,599.66
1 Electric	105691	10 Steam Production	FH$ COP Gearboxes 2017	completed	5724	1/1/2017 0:00	12/31/2017 0:00	7,711.16		7,711.16
1 Electric	105714	10 Steam Production	JSP P320 Comm Controller (Sp18)	open	10160	2/15/2017 0:00	7/30/2018 0:00	8,790.47		8,790.47
1 Electric	105715	10 Steam Production	WAT WFGD Concrete Pad	open	11641	1/31/2017 0:00	6/30/2018 0:00	20,298.45		20,298.45
1 Electric	105716	10 Steam Production	WA1 Simulator	in service	11226	2/15/2017 0:00	1/31/2018 0:00	955,782.61		955,782.61
1 Electric	105717	10 Steam Production	COP Heat Exchangers 2017	completed	5008	2/1/2017 0:00	12/31/2017 0:00	15,775.53		15,775.53
1 Electric	105725	10 Steam Production	URQ Breaker 2220 Cable	posted to CPR	116-242-619	1/1/2017 0:00	12/31/2017 0:00	2,202.13		2,202.13

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OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	105727	10 Steam Production	URQ Instrumentation 2017	in service	117-498-619	1/1/2017 0:00	12/31/2017 0:00	9,171.42		9,171.42
1 Electric	105734	10 Steam Production	URQ 480V Ground Detectors	in service	12022	3/1/2017 0:00	12/31/2017 0:00	35,440.83		35,440.83
1 Electric	105737	10 Steam Production	URQ1 Motor Control Centers	open	10517	4/1/2017 0:00	8/31/2018 0:00	9,643.29		9,643.29
1 Electric	105740	10 Steam Production	URQ Demineralizer PLC 2018	open	12028	2/24/2017 0:00	12/31/2018 0:00	1,320.92		1,320.92
1 Electric	105750	10 Steam Production	WAT Used Oil Storage Tank	open	11649	4/1/2017 0:00	4/30/2018 0:00	52,504.18		52,504.18
1 Electric	105752	10 Steam Production	COP Coal Bunker Silos	open	11101	3/20/2017 0:00	12/30/2018 0:00	533,785.26		533,785.26
1 Electric	105759	10 Steam Production	MC1 Generator Field Insulation	in service	12218	4/1/2017 0:00	12/31/2017 0:00	679,226.21		679,226.21
1 Electric	105760	10 Steam Production	FH$ COP 'B' COAL MILL GEARBOX	completed	11102	9/1/2017 0:00	12/30/2017 0:00	41,736.73		41,736.73
1 Electric	105763	10 Steam Production	MCM1 High Energy Piping	in service	7403	4/17/2017 0:00	12/31/2017 0:00	53,248.44		53,248.44
1 Electric	105764	10 Steam Production	MCM2 High Energy Piping	in service	7403	4/17/2017 0:00	12/31/2017 0:00	41,428.43		41,428.43
1 Electric	105767	10 Steam Production	MCM ID Fan Vibration Monitoring Sys	in service	7670	5/1/2017 0:00	12/31/2017 0:00	59,048.23		59,048.23
1 Electric	105771	10 Steam Production	URQ Valves 2017	completed	117-725-619	4/1/2017 0:00	12/31/2017 0:00	130,007.64		130,007.64
1 Electric	105772	10 Steam Production	WAT Gearboxes 2017	open	113-800-625	4/1/2017 0:00	3/31/2018 0:00	80,330.90		80,330.90
1 Electric	105775	10 Steam Production	WA1 'C' BFBP Main Oil Pump	posted to CPR	117-495-625	5/11/2017 0:00	11/15/2017 0:00	2,292.92		2,292.92
1 Electric	105776	10 Steam Production	WAT Coal Belt #6 Gearbox	in service	113-800-625	5/1/2017 0:00	1/15/2018 0:00	16,288.55		16,288.55
1 Electric	105785	10 Steam Production	WAT Gypsum Radial Stacker Belt	in service	117-755-625	5/30/2017 0:00	1/31/2018 0:00	2,882.16		2,882.16
1 Electric	105788	10 Steam Production	COP Atomizer Disk	posted to CPR	12207	6/1/2017 0:00	12/30/2017 0:00	76,946.51		76,946.51
1 Electric	105795	10 Steam Production	WA1 BFP Recirculation Manual Valve	posted to CPR	117-867-625	6/19/2017 0:00	11/1/2017 0:00	11,828.37		11,828.37
1 Electric	105796	10 Steam Production	UR1 Condenser Tubes	open	11627	6/30/2017 0:00	12/31/2018 0:00	79.55		79.55
1 Electric	105799	10 Steam Production	MC1 LP Turbine Rotor Buckets	in service	7655	5/1/2017 0:00	12/31/2017 0:00	948,480.89		948,480.89
1 Electric	105807	10 Steam Production	FH$ WAT Plant Valves 2017	in service	117-867-625	7/1/2017 0:00	1/31/2018 0:00	5,985.17		5,985.17
1 Electric	105808	10 Steam Production	WAT Coal Belts 2017	in service	113-55-625	7/7/2017 0:00	1/31/2018 0:00	137,013.08		137,013.08
1 Electric	105810	10 Steam Production	URQ SS Office HVAC 2017	posted to CPR	112-367-619	7/15/2017 0:00	12/31/2017 0:00	8,729.86		8,729.86
1 Electric	105813	10 Steam Production	WAT Plant Insturmentation 2017	in service	117-753-625	7/15/2017 0:00	12/31/2017 0:00	6,526.55		6,526.55
1 Electric	105815	10 Steam Production	WA1 Baghouse Fabric Bags	open	4160	1/1/2018 0:00	12/1/2018 0:00	678.65		678.65
1 Electric	105817	10 Steam Production	FH$ WAT Misc Pumps	in service	117-495-625	7/1/2017 0:00	1/31/2018 0:00	17,824.63		17,824.63
1 Electric	105818	10 Steam Production	COP Weld Shop 25T Crane VSD	posted to CPR	5010	7/12/2017 0:00	12/30/2017 0:00	3,269.80		3,269.80
1 Electric	105827	10 Steam Production	WAT Plant Motors 2017	in service	116-138-625	7/15/2017 0:00	1/31/2018 0:00	216,639.48		216,639.48
1 Electric	105829	10 Steam Production	FH$ URQ Asbestos Abatement 2017	completed	113-906-619	8/1/2017 0:00	12/31/2017 0:00	88.26		88.26
1 Electric	105830	10 Steam Production	URQ 25 Ton Hoist Equipment	in service	12472	8/3/2017 0:00	12/31/2017 0:00	2,114.33		2,114.33
1 Electric	105831	10 Steam Production	WAT Plant Heat Exchangers	open	12474	1/1/2017 0:00	1/31/2018 0:00	1.87		1.87
1 Electric	105846	10 Steam Production	JSP Condensate Check Valves	posted to CPR	8633	10/1/2017 0:00	12/31/2017 0:00	2,043.80		2,043.80
1 Electric	105849	10 Steam Production	WAT Waterwall Tubes	in service	113-165-625	9/1/2017 0:00	1/31/2018 0:00	11,263.19		11,263.19
1 Electric	105853	10 Steam Production	COP Plant Ice Machine	posted to CPR	117-802-115	9/1/2017 0:00	12/30/2017 0:00	5,016.40		5,016.40
1 Electric	155005	110 Land and Structures	Install Sys Prot Training Facility	open	11075	7/23/2014 0:00	12/31/2017 0:00	1,131,269.90		1,131,269.90
1 Electric	155078	150 Tools & Test Equipment	Admin WO AFUDC Adjustments	open	890-218-856	11/21/2014 0:00	12/31/2050 0:00	(3,781,571.00)		(3,781,571.00)
1 Electric	155123	150 Tools & Test Equipment	Power Quality Meters	open	10215	1/1/2015 0:00	12/31/2018 0:00	107,450.63		107,450.63
1 Electric	155455	140 Communication Equipment	Purchase/Install CDC/DNP Prot Conv	open	11892	6/20/2016 0:00	3/1/2018 0:00	10,304.71		10,304.71
1 Electric	155500	140 Communication Equipment	Replace entire Radio System	open	11705	11/15/2016 0:00	8/30/2017 0:00	4,571,156.61		4,571,156.61
1 Electric	155517	150 Tools & Test Equipment	SOUTHER REGION TOOLS 2017	in service	840-825-531	1/1/2017 0:00	12/31/2017 0:00	7,529.68		7,529.68
1 Electric	155526	130 Office Furniture and Equipment	CIP5 Network Upgrade	in service	11441	1/23/2017 0:00	12/31/2017 0:00	470,329.24		470,329.24
1 Electric	155529	150 Tools & Test Equipment	2017 - PDNO Misc. Tool Work Order	unitized	840-822-533	1/1/2017 0:00	12/31/2017 0:00	31,274.77		31,274.77
1 Electric	155535	130 Office Furniture and Equipment	RE$ HVAC Replacements - 2017 - RE	in service	7453	1/1/2017 0:00	2/28/2018 0:00	12,172.58		12,172.58
1 Electric	155536	130 Office Furniture and Equipment	PD$ HVAC Replacements - 2017 - IN	completed	7454	1/1/2017 0:00	2/28/2018 0:00	33,977.97		33,977.97
1 Electric	155606	130 Office Furniture and Equipment	CIP5- EMS DNPI Protocol Implem	unitized	11447	3/1/2017 0:00	12/31/2017 0:00	181,688.38		181,688.38
1 Electric	155640	120 Transportation & POE	TRL0012125	posted to CPR	811-136-260	7/6/2017 0:00	11/1/2017 0:00	13,237.74		13,237.74
1 Electric	155641	130 Office Furniture and Equipment	Panasonic Toughbooks CADs for Elect	posted to CPR	12287	9/1/2017 0:00	12/31/2017 0:00	190,407.80		190,407.80
1 Electric	155650	150 Tools & Test Equipment	CEN LAB Air Compressor	open	160-113-138	7/31/2017 0:00	11/20/2017 0:00	2,202.60		2,202.60
1 Electric	155652	150 Tools & Test Equipment	Meter Tester Equipment Replacement	posted to CPR	12351	8/1/2017 0:00	8/31/2017 0:00	9,496.25		9,496.25
1 Electric	155654	130 Office Furniture and Equipment	Toughbooks CAD for Forresters	open	840-773-161	8/10/2017 0:00	12/31/2017 0:00	17,499.19		17,499.19
1 Electric	155656	130 Office Furniture and Equipment	Zoll AED Plus Unit	posted to CPR	12484	8/24/2017 0:00	9/30/2017 0:00	1,325.00		1,325.00
1 Electric	155663	150 Tools & Test Equipment	REPLACE GENERATOR-MT. PLEASANT CREW	completed	12498	9/8/2017 0:00	12/1/2017 0:00	273.18		273.18
1 Electric	159165	159 Electric Intangible Plant	Power Quality Dashboard Software	open	10215	1/1/2015 0:00	12/31/2018 0:00	100,464.72		100,464.72
1 Electric	159174	159 Electric Intangible Plant	Work Management System (WMS)	open	890-217-365	1/20/2015 0:00	3/31/2018 0:00	1,867,672.46		1,867,672.46
1 Electric	159178	159 Electric Intangible Plant	PhaseII-CIS Updates for DER Progrms	open	11790	1/1/2016 0:00	1/31/2018 0:00	368,134.84		368,134.84
1 Electric	159179	159 Electric Intangible Plant	Conduit Manager	open	11899	8/1/2016 0:00	10/1/2017 0:00	36,213.12		36,213.12
1 Electric	159183	159 Electric Intangible Plant	Purchase-Implement of MacroSoft RoD	completed	11774	1/3/2017 0:00	12/31/2017 0:00	142,582.67		142,582.67

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DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	159187	159 Electric Intangible Plant	Archer CIP Patch Process	in service	11439	4/17/2017 0:00	1/31/2018 0:00	85,079.06		85,079.06
1 Electric	159188	159 Electric Intangible Plant	Renewables:Removing Res Solar Sec.	open	11790	11/14/2016 0:00	3/25/2018 0:00	19,623.99		19,623.99
1 Electric	159189	159 Electric Intangible Plant	Renewables Community Solar	open	11790	1/3/2017 0:00	2/28/2018 0:00	114,327.57		114,327.57
1 Electric	161361	15 Nuclear Production	AB Truck Bay LWPS Modification	open	4865	1/1/2003 0:00	12/31/2017 0:00	(166.68)		(166.68)
1 Electric	161682	159 Electric Intangible Plant	VCS - NFPA 805 Software	open	6145	1/1/2006 0:00	12/31/2018 0:00	17,363,426.74		17,363,426.74
1 Electric	162250	159 Electric Intangible Plant	CHAMPS Replacement	open	9947	1/1/2012 0:00	5/31/2018 0:00	14,346,977.48		14,346,977.48
1 Electric	162252	15 Nuclear Production	S/R "Bravo" Chiller Replacement	open	5255	1/1/2012 0:00	12/31/2020 0:00	1,579,064.84		1,579,064.84
1 Electric	162258	15 Nuclear Production	**Replace RMWST Heat Tracing	open	5614	2/1/2012 0:00	12/31/2018 0:00	1,054,424.81		1,054,424.81
1 Electric	162304	159 Electric Intangible Plant	Seismic PRA Project	open	10055	5/1/2012 0:00	12/31/2018 0:00	8,488,360.48		8,488,360.48
1 Electric	162305	159 Electric Intangible Plant	Configuration Mgmt. Software	open	10058	5/1/2012 0:00	12/31/2017 0:00	5,586,291.00		5,586,291.00
1 Electric	162330	159 Electric Intangible Plant	Champs Replacement - Admin.	open	9947	8/23/2011 0:00	3/31/2018 0:00	(7,920,261.14)		(7,920,261.14)
1 Electric	162331	159 Electric Intangible Plant	Config. Mgmt. Software - Admin.	open	10058	5/1/2012 0:00	12/31/2017 0:00	(3,047,668.41)		(3,047,668.41)
1 Electric	162361	15 Nuclear Production	S/R PORV Controls	open	9035	10/15/2012 0:00	12/31/2020 0:00	1,119,313.91		1,119,313.91
1 Electric	162362	15 Nuclear Production	PORV Tailpipe Equalizing Line	open	9035	1/1/2013 0:00	12/31/2020 0:00	682,699.54		682,699.54
1 Electric	162424	15 Nuclear Production	Service Building Roof Replacement	open	7302	7/1/2013 0:00	4/30/2018 0:00	274,776.17		274,776.17
1 Electric	162425	15 Nuclear Production	ASB Renovation	open	10459	7/1/2013 0:00	12/31/2018 0:00	2,434.28		2,434.28
1 Electric	162426	15 Nuclear Production	New Plant Support Building	open	10458	7/1/2013 0:00	4/30/2018 0:00	398,144.47		398,144.47
1 Electric	162488	15 Nuclear Production	Simplex Equipment Replacement	open	10663	12/16/2013 0:00	12/31/2018 0:00	1,930,771.93		1,930,771.93
1 Electric	162500	15 Nuclear Production	OCA Alternate Power	open	4718	2/1/2014 0:00	11/30/2018 0:00	4,498.00		4,498.00
1 Electric	162509	15 Nuclear Production	SW Chemical Treatment Equipment	open	10665	3/1/2014 0:00	12/31/2018 0:00	3,919,012.36		3,919,012.36
1 Electric	162514	15 Nuclear Production	B Loop Aux Crane Replacement	open	10308	3/1/2014 0:00	12/31/2018 0:00	2,087,306.35		2,087,306.35
1 Electric	162554	15 Nuclear Production	New Unit 1 Access Portal	suspended	11033	5/1/2014 0:00	12/31/2019 0:00	186,120.57		186,120.57
1 Electric	162559	15 Nuclear Production	Penstock Piping Project	open	10660	6/2/2014 0:00	12/31/2019 0:00	333,468.44		333,468.44
1 Electric	162567	15 Nuclear Production	Additional Protected Area Grounding	open	10658	7/1/2014 0:00	12/31/2017 0:00	(6,342.14)		(6,342.14)
1 Electric	162585	159 Electric Intangible Plant	OSI PI Software	open	11387	9/15/2014 0:00	6/30/2018 0:00	467,542.28		467,542.28
1 Electric	162589	15 Nuclear Production	SIEM Project	open	9897	10/13/2014 0:00	6/30/2018 0:00	6,094,531.46		6,094,531.46
1 Electric	162610	15 Nuclear Production	Open Phase Detection System	open	11322	1/1/2015 0:00	12/31/2018 0:00	5,346,222.86		5,346,222.86
1 Electric	162615	15 Nuclear Production	AB Roof Replacement	suspended	10047	2/1/2015 0:00	12/31/2018 0:00	64,258.94		64,258.94
1 Electric	162616	15 Nuclear Production	IB & DGB Roof Replacements	suspended	10047	2/1/2015 0:00	12/31/2018 0:00	66,878.70		66,878.70
1 Electric	162622	15 Nuclear Production	Replace Inverters XIT5936 & XIT5937	open	5675	3/2/2015 0:00	12/31/2018 0:00	63,602.14		63,602.14
1 Electric	162637	15 Nuclear Production	DG Exciter Replacement	open	9500	5/1/2015 0:00	12/31/2018 0:00	662,233.45		662,233.45
1 Electric	162648	15 Nuclear Production	NOB TSC HVAC	open	8551	5/18/2015 0:00	12/31/2017 0:00	328,926.26		328,926.26
1 Electric	162649	15 Nuclear Production	NOB TSC HVAC - Admin	open	8551	5/18/2015 0:00	12/31/2017 0:00	(123,788.75)		(123,788.75)
1 Electric	162666	15 Nuclear Production	FLEX Alternate FW Suction Source	open	10291	8/3/2015 0:00	7/31/2018 0:00	3,545,965.25		3,545,965.25
1 Electric	162709	15 Nuclear Production	VCS Unit 1 License Renewal Project	open	11789	12/1/2015 0:00	12/31/2022 0:00	1,800,369.01		1,800,369.01
1 Electric	162770	15 Nuclear Production	CWS Tie-In (Unit 1)	open	11751	6/1/2016 0:00	12/31/2019 0:00	119,092.58		119,092.58
1 Electric	162771	15 Nuclear Production	External Flood Mitigation	open	10667	6/1/2016 0:00	12/31/2018 0:00	370,173.36		370,173.36
1 Electric	162775	159 Electric Intangible Plant	Westems Software	open	10793	7/1/2016 0:00	12/31/2018 0:00	172,442.26		172,442.26
1 Electric	162777	159 Electric Intangible Plant	VCS Equipment On-Line Monitoring	posted to CPR	10799	8/1/2016 0:00	12/31/2017 0:00	137,251.90		137,251.90
1 Electric	162778	159 Electric Intangible Plant	VCS Equip. On-Line Mon. - Admin	posted to CPR	10799	8/1/2016 0:00	12/31/2017 0:00	(76,245.25)		(76,245.25)
1 Electric	162796	159 Electric Intangible Plant	WebEOC ENF Board	posted to CPR	10351	9/13/2016 0:00	12/31/2017 0:00	104.33	(104.33)	0.00
1 Electric	162799	15 Nuclear Production	NC$ CORA Hand-Held Computers	unitized	10344	9/1/2016 0:00	10/31/2017 0:00	6,935.16		6,935.16
1 Electric	162802	15 Nuclear Production	Spare Main Gen. Storage Facility	open	6751	10/17/2016 0:00	6/30/2018 0:00	157,281.22		157,281.22
1 Electric	162809	15 Nuclear Production	FW Control Valve Positioners	open	8799	11/1/2016 0:00	1/31/2019 0:00	20,449.94		20,449.94
1 Electric	162810	15 Nuclear Production	Replace LD System Recorders	completed	10014	1/1/2017 0:00	12/31/2017 0:00	80,381.43		80,381.43
1 Electric	162815	15 Nuclear Production	Spent Fuel Storage Casks	open	6754	1/1/2017 0:00	12/31/2019 0:00	280,388.74		280,388.74
1 Electric	162823	15 Nuclear Production	EP CDA Cyber Security Remediation	open	9897	1/12/2017 0:00	7/31/2018 0:00	419,190.56		419,190.56
1 Electric	162824	15 Nuclear Production	P.A. Bullet Resistant Enslosures	open	4022	1/18/2017 0:00	12/31/2018 0:00	696,068.08		696,068.08
1 Electric	162825	159 Electric Intangible Plant	CyberWiz Pro Software Upgrade	posted to CPR	12075	2/14/2017 0:00	12/31/2017 0:00	43,852.63		43,852.63
1 Electric	162837	15 Nuclear Production	DG Heat Exchanger Tube Bundles	open	12043	4/1/2017 0:00	12/31/2019 0:00	325,052.72		325,052.72
1 Electric	162838	15 Nuclear Production	RCP Oil Enclosures	open	12040	4/1/2017 0:00	10/31/2023 0:00	44,979.18		44,979.18
1 Electric	162841	159 Electric Intangible Plant	NC$ Empact DNP Functionality	completed	11465	4/17/2017 0:00	12/31/2017 0:00	18,690.21		18,690.21
1 Electric	162857	15 Nuclear Production	Cable Replacement	in service	9893	5/5/2017 0:00	12/31/2017 0:00	781,753.22		781,753.22
1 Electric	162878	15 Nuclear Production	Offsite Water System (OWS)	open	11314	8/14/2017 0:00	5/31/2018 0:00	145,710.93		145,710.93
1 Electric	201173	20 Hydro Production	FPS 480V MCC & 13.8KV Switchgear	open	3461	2/16/2015 0:00	12/30/2018 0:00	698,255.89		698,255.89
1 Electric	201191	20 Hydro Production	SAL Controls	open	9780	5/29/2015 0:00	12/30/2017 0:00	16,292.03		16,292.03
1 Electric	201248	20 Hydro Production	PSH 115KV Protective Relays	in service	11606	6/1/2016 0:00	10/30/2016 0:00	35,348.26		35,348.26

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RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	201265	20 Hydro Production	STN CRK Turbine Room Cranes	in service	10205	7/1/2016 0:00	4/30/2018 0:00	248,896.18		248,896.18
1 Electric	201294	20 Hydro Production	FH$ PSH #4 Crest Gate Hydra Cylinde	completed	3171	8/14/2017 0:00	12/30/2017 0:00	99,058.51		99,058.51
1 Electric	201297	20 Hydro Production	SAL Work Boat	completed	4643	2/16/2017 0:00	12/31/2017 0:00	21,970.29		21,970.29
1 Electric	201301	20 Hydro Production	STN CRK Dam Stability Anchors	open	10204	2/27/2017 0:00	12/31/2019 0:00	23,829.68		23,829.68
1 Electric	201309	20 Hydro Production	FH$ PSH Unit 5 Guide Bearing Oil Co	posted to CPR	3172	7/1/2017 0:00	9/30/2017 0:00	22,849.53		22,849.53
1 Electric	201313	20 Hydro Production	NSH Sluice Gate Actuator Gearboxes	open	11596	7/3/2017 0:00	12/30/2017 0:00	3,633.62		3,633.62
1 Electric	201314	20 Hydro Production	FPS Unit #6 C Stator Heat Exchanger	posted to CPR	135-182-631	6/1/2017 0:00	12/30/2017 0:00	8,598.59		8,598.59
1 Electric	201317	20 Hydro Production	FPS 7&8 Penstock Expansion Joint	open	3460	4/8/2018 0:00	6/30/2018 0:00	47,628.76		47,628.76
1 Electric	201320	20 Hydro Production	FPS #5 "B" Stator Heat Exchanger	in service	135-182-631	9/15/2017 0:00	11/15/2017 0:00	8,620.27		8,620.27
1 Electric	201321	20 Hydro Production	SCH #8 Generator Stator Rewind	open	135-157-484	8/1/2017 0:00	6/30/2018 0:00	2,025.30		2,025.30
1 Electric	201322	20 Hydro Production	FH$ SCH Station Service Switchgear	in service	11911	9/1/2017 0:00	12/31/2017 0:00	31,996.57		31,996.57
1 Electric	201326	20 Hydro Production	FPS Emergency Station Service Cable	open	11127	8/14/2017 0:00	5/30/2018 0:00	104,026.58		104,026.58
1 Electric	201333	20 Hydro Production	FPS Breaker Remote Racking System	in service	10176	10/2/2017 0:00	12/30/2017 0:00	14,444.88		14,444.88
1 Electric	300957	30 Electric Other Production	PGT Motor Control Centers	open	4686	1/29/2016 0:00	12/30/2018 0:00	33,097.46		33,097.46
1 Electric	300984	30 Electric Other Production	UGT4 Station Service Disconnects	open	5468	7/1/2016 0:00	6/30/2018 0:00	16,418.68		16,418.68
1 Electric	301022	30 Electric Other Production	URQ 5&6 Chiller Recirc System	open	12025	3/1/2017 0:00	12/31/2017 0:00	23,793.27		23,793.27
1 Electric	301042	30 Electric Other Production	UGT4 Cooling Tower	open	8202	2/1/2017 0:00	8/31/2018 0:00	11,920.99		11,920.99
1 Electric	301046	30 Electric Other Production	UGT 480V Ground Detectors	completed	11986	3/1/2017 0:00	12/31/2017 0:00	16,435.80		16,435.80
1 Electric	301048	30 Electric Other Production	UGT Chiller PLC 2018	open	12027	2/24/2017 0:00	12/31/2018 0:00	1,320.90		1,320.90
1 Electric	301052	30 Electric Other Production	UGT 5&6 Instrumentation 2017	completed	11614	1/1/2017 0:00	12/31/2017 0:00	2,585.39		2,585.39
1 Electric	301057	30 Electric Other Production	UGT HVAC 2017	completed	11776	4/1/2017 0:00	12/31/2017 0:00	16,832.66		16,832.66
1 Electric	301059	30 Electric Other Production	HAG Water Treatment PLC	open	12222	4/1/2017 0:00	12/31/2017 0:00	13,354.81		13,354.81
1 Electric	301062	30 Electric Other Production	UGT Valves 2017	in service	6920	4/27/2017 0:00	12/31/2017 0:00	14,566.94		14,566.94
1 Electric	301063	30 Electric Other Production	UGT 5&6 PEECC Batteries 2017	in service	11264	5/1/2017 0:00	12/31/2017 0:00	262.49		262.49
1 Electric	301064	30 Electric Other Production	JSP HRSG Tube Protective Relays (F)	posted to CPR	12225	5/1/2017 0:00	12/30/2017 0:00	16,955.36		16,955.36
1 Electric	301065	30 Electric Other Production	FH$ PGT #3 Torque Converter	completed	7643	9/11/2017 0:00	12/30/2017 0:00	18,170.05		18,170.05
1 Electric	301067	30 Electric Other Production	UGT Closed Cooling Tower Parts 2017	completed	11635	5/16/2017 0:00	12/31/2017 0:00	36,120.01		36,120.01
1 Electric	301075	30 Electric Other Production	FH$ JSP Fuel Oil Level Transmitter	unitized	6272	8/30/2017 0:00	12/30/2017 0:00	5,246.09		5,246.09
1 Electric	301076	30 Electric Other Production	JSP Flame Scanners	posted to CPR	7108	6/1/2017 0:00	12/30/2017 0:00	12,718.23		12,718.23
1 Electric	301079	30 Electric Other Production	CGT #1 Control Components	open	4558	9/4/2017 0:00	12/11/2017 0:00	4,140.26		4,140.26
1 Electric	301081	30 Electric Other Production	JSP GT1, 2 & 3 Filter Replacement	open	5492	9/1/2017 0:00	7/31/2018 0:00	2,829.51		2,829.51
1 Electric	301083	30 Electric Other Production	FH$ JSP GT2 Continuous Blowdown Val	completed	5493	10/1/2017 0:00	12/15/2017 0:00	1,289.88		1,289.88
1 Electric	301094	30 Electric Other Production	JSP #1Chiller Isolation Valve	unitized	5493	8/1/2017 0:00	11/1/2017 0:00	7,632.84		7,632.84
1 Electric	400626	40 Elec Overhead Transmission Line	Yemassee-Burton 230 (115) kV	open	6444	1/1/2006 0:00	6/30/2020 0:00	13,938,348.83		13,938,348.83
1 Electric	400694	40 Elec Overhead Transmission Line	Victory Gardens-Circle Dr. 115kV	open	5763	8/1/2004 0:00	12/31/2018 0:00	268,991.07		268,991.07
1 Electric	400749	40 Elec Overhead Transmission Line	Ridgeville 115kV Tap Add 2nd Bank*	posted to CPR	8030	6/1/2016 0:00	11/1/2017 0:00	1,126.89	(1,126.89)	0.00
1 Electric	400813	40 Elec Overhead Transmission Line	Coit - Kendrick 33 kV line #1	open	9108	1/21/2010 0:00	12/31/2017 0:00	23,537.09		23,537.09
1 Electric	400836	40 Elec Overhead Transmission Line	#0270B:Thomas Is.-Jack Primus115	open	7705	7/1/2010 0:00	3/31/2018 0:00	4,157,996.67		4,157,996.67
1 Electric	400869	40 Elec Overhead Transmission Line	Summerville-Pepperhill 230kV Line	open	252-65-146	5/1/2011 0:00	8/1/2020 0:00	344,793.78		344,793.78
1 Electric	400920	40 Elec Overhead Transmission Line	Sewee 115kV Sub Tap: R/W	in service	4312	8/20/2002 0:00	11/30/2017 0:00	219,431.28		219,431.28
1 Electric	400986	40 Elec Overhead Transmission Line	Urquhart-Graniteville Rebuild 230kV	open	7688	1/1/2014 0:00	12/31/2019 0:00	492,822.26		492,822.26
1 Electric	400998	40 Elec Overhead Transmission Line	Hardeeville Tap - Bluffton 115 kV	open	11041	5/20/2014 0:00	3/31/2018 0:00	177,585.95		177,585.95
1 Electric	401008	40 Elec Overhead Transmission Line	Sal Hyd Harbison 115 Reterm to LM	open	11060	6/19/2014 0:00	11/30/2019 0:00	1,140,451.81		1,140,451.81
1 Electric	401010	40 Elec Overhead Transmission Line	Williams-Faber Place Replace Strs	open	11091	8/4/2014 0:00	3/31/2018 0:00	535,652.29		535,652.29
1 Electric	401029	40 Elec Overhead Transmission Line	Frogmore-Ladies Isle 115kV Add ROW	open	11513	1/26/2015 0:00	12/31/2017 0:00	6,121.50		6,121.50
1 Electric	401030	40 Elec Overhead Transmission Line	Faber Place - Charlotte St. 115kV	open	9749	4/23/2015 0:00	12/29/2017 0:00	1,466,228.18		1,466,228.18
1 Electric	401031	40 Elec Overhead Transmission Line	Faber Place - Hagood 115kV Line#2	open	9748	4/23/2015 0:00	12/29/2017 0:00	843,536.35		843,536.35
1 Electric	401032	40 Elec Overhead Transmission Line	Queensboro SW Sta - Terminate Lines	open	11529	3/10/2015 0:00	11/30/2017 0:00	432,261.40		432,261.40
1 Electric	401036	40 Elec Overhead Transmission Line	Yem-McIntosh 115kV: Thermal Uprate	open	11577	7/1/2015 0:00	3/1/2018 0:00	324,354.46		324,354.46
1 Electric	401038	40 Elec Overhead Transmission Line	AMW-Cainhoy:Rebld SPDC B795	open	8400	7/1/2015 0:00	3/3/2019 0:00	297,806.00		297,806.00
1 Electric	401041	40 Elec Overhead Transmission Line	Burton-St. Hel. Isnd 115kV G-Line	open	11608	7/17/2015 0:00	3/31/2018 0:00	385,270.08		385,270.08
1 Electric	401043	40 Elec Overhead Transmission Line	Ladies Is-Meadowbrook 115kV-rebuild	open	9720	8/20/2015 0:00	3/31/2018 0:00	8,417.57		8,417.57
1 Electric	401058	40 Elec Overhead Transmission Line	Williams St-Coit 115 kV Relocate	open	11787	10/14/2015 0:00	12/31/2018 0:00	108,253.38		108,253.38
1 Electric	401078	40 Elec Overhead Transmission Line	Church Ck-St Andrews 115kV-repl str	open	11850	3/3/2016 0:00	3/31/2018 0:00	16,817.17		16,817.17
1 Electric	401080	40 Elec Overhead Transmission Line	Yemassee-Burton 115kV Acquire R/W	open	11868	4/21/2016 0:00	12/29/2017 0:00	6,850.25		6,850.25
1 Electric	401092	40 Elec Overhead Transmission Line	Hopkins 230-115kV: Fold In ROW	open	11933	8/10/2016 0:00	12/31/2017 0:00	122,115.88		122,115.88
1 Electric	401094	40 Elec Overhead Transmission Line	Hopkins 230-115kV Sub: Fold-In	open	11202	9/26/2016 0:00	11/30/2018 0:00	61,329.51		61,329.51

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RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	401097	40 Elec Overhead Transmission Line	Eastover-Sumter(DUKE)115kV Tie	open	12142	9/28/2016 0:00	3/31/2019 0:00	708.57		708.57
1 Electric	401098	40 Elec Overhead Transmission Line	Burton 46kV Tie: Remove Switch	open	12143	10/3/2016 0:00	5/1/2018 0:00	453.33		453.33
1 Electric	401101	40 Elec Overhead Transmission Line	Canadys 230kV Sub:Reterminate Lines	open	11692	10/31/2016 0:00	5/1/2019 0:00	20,198.94		20,198.94
1 Electric	401102	40 Elec Overhead Transmission Line	Sewee Sub:115kV Tap to Commonwealth	open	7673	11/10/2016 0:00	8/1/2018 0:00	15,312.51		15,312.51
1 Electric	401110	40 Elec Overhead Transmission Line	PD$ Estill Southside 46kV Sub Tap L	completed	12161	11/8/2016 0:00	12/29/2017 0:00	11,611.49		11,611.49
1 Electric	401111	40 Elec Overhead Transmission Line	Adams Run-Red House Rd 46kV Line	open	12157	11/21/2016 0:00	3/29/2018 0:00	201,171.02		201,171.02
1 Electric	401112	40 Elec Overhead Transmission Line	Jasper Constr Sub - add Motor Mechs	open	12166	11/28/2016 0:00	12/29/2017 0:00	33,189.18		33,189.18
1 Electric	401114	40 Elec Overhead Transmission Line	Hugh Leatherman 115-13.8kV RW	open	12168	12/19/2016 0:00	12/31/2017 0:00	8,589.54		8,589.54
1 Electric	401115	40 Elec Overhead Transmission Line	230kv Minor Capital Work Order 2017	completed	6500	1/1/2017 0:00	12/31/2017 0:00	499,915.71		499,915.71
1 Electric	401116	40 Elec Overhead Transmission Line	PD$ Project # 008117D-SRS Transm.	in service	243-276-533	1/1/2017 0:00	12/31/2017 0:00	38,383.94		38,383.94
1 Electric	401117	40 Elec Overhead Transmission Line	115kv Minor Capital Work Order 2017	completed	243-276-533	1/1/2017 0:00	12/31/2017 0:00	458,575.67		458,575.67
1 Electric	401118	40 Elec Overhead Transmission Line	PD$ 46kv Minor Capital Work Ord2017	completed	333-34-533	1/1/2017 0:00	12/31/2017 0:00	65,826.60		65,826.60
1 Electric	401119	40 Elec Overhead Transmission Line	33kv Minor Capital Work Order 2017	completed	233-171-533	1/1/2017 0:00	12/31/2017 0:00	21,303.08		21,303.08
1 Electric	401120	40 Elec Overhead Transmission Line	PDSO 2017 OH 46KV TRANSMISSION	in service	3737	1/1/2017 0:00	12/31/2017 0:00	111,925.64		111,925.64
1 Electric	401121	40 Elec Overhead Transmission Line	PDSO 2017 OH 115KV TRANSMISSION	in service	243-286-531	1/1/2017 0:00	12/31/2017 0:00	339,208.72		339,208.72
1 Electric	401122	40 Elec Overhead Transmission Line	PDSO 2017 OH 230KV TRANSMISSION	in service	4039	1/1/2017 0:00	12/31/2017 0:00	53,625.05		53,625.05
1 Electric	401125	40 Elec Overhead Transmission Line	Palmetto Rail 115kV Tap Acquire R/W	open	12188	3/3/2017 0:00	12/29/2017 0:00	199.34		199.34
1 Electric	401126	40 Elec Overhead Transmission Line	Saluda Hydro: Rct Harbison & MCM#2	open	12191	3/6/2017 0:00	11/30/2018 0:00	75,429.78		75,429.78
1 Electric	401127	40 Elec Overhead Transmission Line	Williams-MP#2: Replace Strs #4-#21	open	12193	3/3/2017 0:00	8/31/2018 0:00	2,575.36		2,575.36
1 Electric	401128	40 Elec Overhead Transmission Line	Church Crk- Faber Pl Ashley River	open	11930	3/24/2017 0:00	5/31/2018 0:00	4,998.62		4,998.62
1 Electric	401129	40 Elec Overhead Transmission Line	Park St. upgrade to 115kV projects	open	12216	4/1/2017 0:00	12/31/2019 0:00	28,488.75		28,488.75
1 Electric	401131	40 Elec Overhead Transmission Line	Urquhart 115kV Sub Relocate	open	11935	4/25/2017 0:00	5/31/2018 0:00	20,241.82		20,241.82
1 Electric	401133	40 Elec Overhead Transmission Line	Yemassee-Burton 115kV #1-Replace	open	12233	5/22/2017 0:00	7/31/2018 0:00	7,351.16		7,351.16
1 Electric	401135	40 Elec Overhead Transmission Line	Kronotex 115 kv tap #2	open	12238	6/6/2017 0:00	4/1/2019 0:00	31,257.20		31,257.20
1 Electric	401136	40 Elec Overhead Transmission Line	Cainhoy-MP 115kV:Wando Crossing	open	12269	6/19/2017 0:00	11/4/2018 0:00	14,371.12		14,371.12
1 Electric	401137	40 Elec Overhead Transmission Line	Denny Ter - Harbison 115kV Rebuild	open	12275	6/29/2017 0:00	10/31/2018 0:00	13,950.66		13,950.66
1 Electric	401138	40 Elec Overhead Transmission Line	SRS Station 14-53: Add 2 ADSS wires	open	12289	7/12/2017 0:00	9/30/2018 0:00	8,826.14		8,826.14
1 Electric	401139	40 Elec Overhead Transmission Line	Install 1-way switch for SCPSA Tap	open	12291	7/13/2017 0:00	12/31/2018 0:00	392.07		392.07
1 Electric	401140	40 Elec Overhead Transmission Line	Graniteville-Graniteville #2 115 kV	open	12293	7/17/2017 0:00	11/30/2019 0:00	7,437.37		7,437.37
1 Electric	401142	40 Elec Overhead Transmission Line	Jushi 115kV Fold-In: CIP-Hopkins	open	12123	7/17/2017 0:00	2/1/2019 0:00	161,194.84		161,194.84
1 Electric	401143	40 Elec Overhead Transmission Line	Kronotex 115kV Tap #2, Acquire R/W	open	12280	7/14/2017 0:00	12/31/2017 0:00	1,042.04		1,042.04
1 Electric	401145	40 Elec Overhead Transmission Line	Cooper River Sub 115 kV Fold-In	open	12482	8/18/2017 0:00	11/30/2018 0:00	5,014.31		5,014.31
1 Electric	460015	46 Elec Ovrhead Tran Line Non BLRA	Dunbar Rd.-Orangeburg 115 kV	open	9977	12/7/2011 0:00	6/1/2018 0:00	994,332.82		994,332.82
1 Electric	460023	46 Elec Ovrhead Tran Line Non BLRA	Dunbar Rd-Orangeburg 115 kV	open	9979	2/6/2012 0:00	12/31/2018 0:00	11,802,981.16		11,802,981.16
1 Electric	460036	46 Elec Ovrhead Tran Line Non BLRA	VCS2-St.George 1&2 Add ROW	in service	11004	4/4/2014 0:00	6/1/2018 0:00	1,405,332.56		1,405,332.56
1 Electric	460037	46 Elec Ovrhead Tran Line Non BLRA	St George-Summerville 230kV Line #2	open	11011	4/1/2014 0:00	12/31/2018 0:00	13,611,444.55		13,611,444.55
1 Electric	500703	50 Elec Transmission Substation	Urquhart Add Switch House	open	7059	9/18/2009 0:00	12/31/2018 0:00	3,709,069.26		3,709,069.26
1 Electric	500719	50 Elec Transmission Substation	Urquhart Replace DFR	open	8957	1/15/2010 0:00	12/31/2018 0:00	90,146.13		90,146.13
1 Electric	500735	50 Elec Transmission Substation	Summerville 230kV- Improve Drainage	open	9183	6/1/2010 0:00	12/31/2017 0:00	156,601.21		156,601.21
1 Electric	500758	50 Elec Transmission Substation	Thomas Island Sub.: Add Jack Primus	open	8386	10/14/2009 0:00	12/1/2017 0:00	181,265.35		181,265.35
1 Electric	500768	50 Elec Transmission Substation	SRS RTU Replace Station 21 & 22	open	9622	3/15/2011 0:00	12/29/2017 0:00	96,739.84		96,739.84
1 Electric	500846	50 Elec Transmission Substation	PD$ Parr Sub-Repl Pnl, Add Lightn M	posted to CPR	10472	7/29/2013 0:00	4/1/2018 0:00	155,529.78		155,529.78
1 Electric	500850	50 Elec Transmission Substation	Saluda Hyd Sub: Ugd 115 Term to SRT	open	10489	8/5/2013 0:00	10/1/2018 0:00	672,667.62		672,667.62
1 Electric	500875	50 Elec Transmission Substation	Burton Substation - Add 115kV Term.	open	6446	3/6/2014 0:00	5/1/2018 0:00	1,364,404.19		1,364,404.19
1 Electric	500893	50 Elec Transmission Substation	O'burg East Sub:2 230kV Terms	open	11047	6/1/2014 0:00	2/28/2018 0:00	2,726,655.53		2,726,655.53
1 Electric	500899	50 Elec Transmission Substation	Wateree Station 230kV Sub #2531	open	10616	8/8/2014 0:00	12/31/2017 0:00	1,149,787.23		1,149,787.23
1 Electric	500945	50 Elec Transmission Substation	Queensboro Transmission Sub #2057	open	6406	3/3/2015 0:00	5/31/2018 0:00	3,668,377.72		3,668,377.72
1 Electric	500946	50 Elec Transmission Substation	Faber Pl Sub: Add 115kv Terminal	open	9879	2/5/2015 0:00	5/31/2018 0:00	535,822.26		535,822.26
1 Electric	500947	50 Elec Transmission Substation	Hagood Sub: Add 115kv Term. to FP.	open	9880	2/5/2015 0:00	5/31/2018 0:00	134,239.94		134,239.94
1 Electric	500956	50 Elec Transmission Substation	Batesburg Trans. Sub: Add Transfmr	completed	11548	4/9/2015 0:00	11/22/2017 0:00	2,318,350.69		2,318,350.69
1 Electric	500968	50 Elec Transmission Substation	CIPv5: 2015 Low Impact Northern Div	open	11290	8/10/2015 0:00	12/31/2017 0:00	226,197.66		226,197.66
1 Electric	500972	50 Elec Transmission Substation	Urquhart Station Sub #2501	open	11779	9/8/2015 0:00	7/31/2018 0:00	914,015.35		914,015.35
1 Electric	500973	50 Elec Transmission Substation	Non-CIP FRAD Replacement	in service	7931	9/10/2015 0:00	2/28/2018 0:00	581,799.36		581,799.36
1 Electric	500987	50 Elec Transmission Substation	AMW: Upgrade Cainhoy #1 & #2 115kV	open	8947	12/1/2015 0:00	2/1/2019 0:00	182,662.64		182,662.64
1 Electric	500988	50 Elec Transmission Substation	Calhoun County Sub-Relocate SCADA P	open	11797	2/1/2016 0:00	5/1/2018 0:00	446,883.11		446,883.11
1 Electric	500998	50 Elec Transmission Substation	Variuos Trans Sub SPCC 2016	completed	11826	1/7/2016 0:00	1/4/2018 0:00	469,091.32		469,091.32
1 Electric	501005	50 Elec Transmission Substation	Hopkins-Add Autobank,BB Tie, 2 Term	open	11203	3/16/2016 0:00	5/31/2018 0:00	2,688,574.37		2,688,574.37

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1 Electric	501011	50 Elec Transmission Substation	PD$ Various PDNO Subs Re 9300w/311L	in service	11857	3/29/2016 0:00	12/31/2017 0:00	158,236.67		158,236.67
1 Electric	501016	50 Elec Transmission Substation	Blackville Trans - Add 115-12kV Bnk	open	11863	4/11/2016 0:00	12/31/2017 0:00	1,457,658.21		1,457,658.21
1 Electric	501018	50 Elec Transmission Substation	Summerville 230kV Sub. #2071	open	10257	6/1/2016 0:00	5/1/2018 0:00	426,040.29		426,040.29
1 Electric	501023	50 Elec Transmission Substation	SRP Series Reactors	open	12114	7/26/2016 0:00	4/23/2018 0:00	62,967.77		62,967.77
1 Electric	501024	50 Elec Transmission Substation	Convert 115kV switch 5634 to FLB	open	11948	9/1/2016 0:00	2/28/2018 0:00	42,121.43		42,121.43
1 Electric	501025	50 Elec Transmission Substation	Rader-Upgrade Low Side Bus Work	open	12037	9/12/2016 0:00	7/31/2019 0:00	87,528.58		87,528.58
1 Electric	501026	50 Elec Transmission Substation	Okatie 230/115kV: Construct	open	12136	9/19/2016 0:00	12/31/2020 0:00	2,932.79		2,932.79
1 Electric	501029	50 Elec Transmission Substation	Fence/Gate Install- FFPS SUB	in service	4842	5/22/2017 0:00	12/31/2017 0:00	292.16		292.16
1 Electric	501036	50 Elec Transmission Substation	PD$ Minor Capital Trans Sub 2017	completed	6501	1/18/2017 0:00	12/31/2017 0:00	201,919.17		201,919.17
1 Electric	501037	50 Elec Transmission Substation	Faber Place - Bus Tie Breaker	open	11714	1/30/2018 0:00	2/28/2020 0:00	1,011.53		1,011.53
1 Electric	501038	50 Elec Transmission Substation	PDSO SUBST 46KV IMPROVEMENTS	in service	3745	1/1/2017 0:00	12/31/2017 0:00	28,423.28		28,423.28
1 Electric	501039	50 Elec Transmission Substation	PDSO 2017 115KV SUB. IMPROVEMENTS	in service	343-408-531	1/1/2017 0:00	12/31/2017 0:00	101,192.27		101,192.27
1 Electric	501040	50 Elec Transmission Substation	PDSO 2017 230KV SUB. IMPROVEMENTS	in service	5300	1/1/2017 0:00	12/31/2017 0:00	63,757.06		63,757.06
1 Electric	501041	50 Elec Transmission Substation	Various Transm Subs SPCC Oil 2017	completed	12176	7/1/2017 0:00	12/30/2017 0:00	20,582.94		20,582.94
1 Electric	501042	50 Elec Transmission Substation	Graniteville #1 and #2 RTU Upgrade	open	12171	1/24/2017 0:00	12/31/2017 0:00	51,307.40		51,307.40
1 Electric	501043	50 Elec Transmission Substation	Cainhoy Trans: add 115-23kV Dist.	open	10606	1/24/2017 0:00	5/31/2018 0:00	102,299.86		102,299.86
1 Electric	501044	50 Elec Transmission Substation	Blackville Trans: Add Reverse Flow	open	12179	2/1/2017 0:00	2/15/2018 0:00	116,116.14		116,116.14
1 Electric	501046	50 Elec Transmission Substation	Wat: Repl Carrier on Hopkins 230 Ln	open	12183	2/15/2017 0:00	10/31/2018 0:00	18,442.28		18,442.28
1 Electric	501047	50 Elec Transmission Substation	CIP-Replace Hopkins relay panel	open	12184	2/15/2017 0:00	10/31/2018 0:00	39,708.31		39,708.31
1 Electric	501048	50 Elec Transmission Substation	PD$ Denny T Sub: Rep Pnl on Ckt8312	posted to CPR	12186	2/21/2017 0:00	8/1/2018 0:00	164,819.04		164,819.04
1 Electric	501053	50 Elec Transmission Substation	Williams Gas Turbine Repl HS Switch	open	12217	4/10/2017 0:00	7/31/2018 0:00	89,225.37		89,225.37
1 Electric	501054	50 Elec Transmission Substation	Edenwood Sub - Rep 4 bkrs	open	12230	5/12/2017 0:00	2/1/2018 0:00	456,997.20		456,997.20
1 Electric	501056	50 Elec Transmission Substation	Rader Sub: Replace Failed Transfor	open	12273	6/27/2017 0:00	3/1/2018 0:00	5,082.13		5,082.13
1 Electric	501057	50 Elec Transmission Substation	G'ville Trans: Upgd. 115 Terminals	open	12117	7/7/2017 0:00	7/31/2019 0:00	4,883.05		4,883.05
1 Electric	501058	50 Elec Transmission Substation	PD$ Dunbar Rd Sub:Rpl Pnl On Ck1112	completed	12274	7/1/2017 0:00	2/28/2018 0:00	19,281.47		19,281.47
1 Electric	501060	50 Elec Transmission Substation	Urq 230kV: Upgd G'ville 230kV term	open	12115	8/1/2017 0:00	7/31/2019 0:00	619.40		619.40
1 Electric	501061	50 Elec Transmission Substation	G'ville Trans: Add new 230kV Term	open	12116	8/1/2017 0:00	7/31/2019 0:00	928.38		928.38
1 Electric	501062	50 Elec Transmission Substation	G'ville #2: Upgrade 230 & 115 Terms	open	12278	8/1/2017 0:00	7/31/2019 0:00	941.85		941.85
1 Electric	501063	50 Elec Transmission Substation	G'ville #2: Add New 115kV Term	open	12279	8/1/2017 0:00	7/31/2019 0:00	455.96		455.96
1 Electric	501065	50 Elec Transmission Substation	Coit-Replace Bkr 2832	in service	12352	8/15/2017 0:00	2/28/2018 0:00	217.36		217.36
1 Electric	501066	50 Elec Transmission Substation	St. Andrews - Replace Panels	open	12476	8/11/2017 0:00	2/28/2018 0:00	12,563.42		12,563.42
1 Electric	501067	50 Elec Transmission Substation	Church Creek - Replace Panel	open	12477	8/11/2017 0:00	2/28/2018 0:00	5,955.48		5,955.48
1 Electric	550666	55 Elec Distribution Substation	Sewee Sub.No. 807- Construct	open	4306	8/20/2012 0:00	7/1/2019 0:00	1,132,018.91		1,132,018.91
1 Electric	550751	55 Elec Distribution Substation	Ridgeville 115-46kV - Inst. 22.4MVA	open	7984	7/1/2008 0:00	12/18/2017 0:00	1,354,193.00		1,354,193.00
1 Electric	550820	55 Elec Distribution Substation	Port Royal Sub: Add Land 2nd Bank	open	8815	6/1/2009 0:00	12/29/2017 0:00	32,962.66		32,962.66
1 Electric	550859	55 Elec Distribution Substation	Jack Primus 115-23kv Sub: Construct	open	7704	10/1/2009 0:00	8/31/2018 0:00	2,208,376.98		2,208,376.98
1 Electric	550875	55 Elec Distribution Substation	Sandhill: Add Gravel, Fence & Grnd.	in service	9671	7/14/2011 0:00	7/31/2018 0:00	46,348.70		46,348.70
1 Electric	550979	55 Elec Distribution Substation	ACS RTU Replacement - 2015	in service	11296	8/19/2014 0:00	12/29/2017 0:00	417,293.02		417,293.02
1 Electric	551019	55 Elec Distribution Substation	Chapin Business Park 230-23KV	open	11707	7/31/2015 0:00	2/28/2020 0:00	80,462.21		80,462.21
1 Electric	551030	55 Elec Distribution Substation	Riverland Terrace: Replace Fence	open	11829	1/19/2016 0:00	12/15/2017 0:00	2,333.03		2,333.03
1 Electric	551034	55 Elec Distribution Substation	Sweetwater 115-12kV Sub: Incr. Capc	open	11845	3/1/2016 0:00	12/30/2017 0:00	1,347,206.23		1,347,206.23
1 Electric	551036	55 Elec Distribution Substation	Estill Southside Add Bank & 1 Bkr	in service	11710	3/16/2016 0:00	8/30/2018 0:00	328,861.87		328,861.87
1 Electric	551047	55 Elec Distribution Substation	Upgrade Various RTUs at Solar Impac	in service	11888	6/20/2016 0:00	3/31/2018 0:00	240,038.11		240,038.11
1 Electric	551048	55 Elec Distribution Substation	Replace SRS SCADA Prot. Converters	open	11893	6/20/2016 0:00	12/29/2017 0:00	25,894.65		25,894.65
1 Electric	551054	55 Elec Distribution Substation	Ingleside 115/23kV Sub: Site	open	12131	8/2/2016 0:00	11/30/2017 0:00	11,719.29		11,719.29
1 Electric	551055	55 Elec Distribution Substation	Coosawhatchie 115-23kV Sub: Site	open	12133	8/10/2016 0:00	9/1/2018 0:00	3,949.55		3,949.55
1 Electric	551060	55 Elec Distribution Substation	Chapin 115/23kV Sub: Acquire Site	open	12150	10/10/2016 0:00	12/31/2016 0:00	215.50		215.50
1 Electric	551062	55 Elec Distribution Substation	Lexington Ind Park-Incr Cap Bank 2	open	11173	11/1/2016 0:00	5/1/2018 0:00	20,534.77		20,534.77
1 Electric	551063	55 Elec Distribution Substation	Park St - Improvements	open	12054	11/1/2016 0:00	7/1/2020 0:00	67,162.82		67,162.82
1 Electric	551069	55 Elec Distribution Substation	Bluffton - Add Dist Feeder	completed	12159	11/28/2016 0:00	11/29/2017 0:00	98,135.88		98,135.88
1 Electric	551071	55 Elec Distribution Substation	PD$ Cooper River 115kV Sub Site	completed	12170	12/21/2016 0:00	12/1/2017 0:00	4,437.96		4,437.96
1 Electric	551072	55 Elec Distribution Substation	PD$ SRS Sub Minor Cap Minor Cap2017	in service	243-277-533	1/1/2017 0:00	12/31/2017 0:00	14,328.10		14,328.10
1 Electric	551074	55 Elec Distribution Substation	Minor Capital DIST/CUST Sub 2017	completed	413-565-533	1/1/2017 0:00	12/31/2017 0:00	177,612.53		177,612.53
1 Electric	551075	55 Elec Distribution Substation	PDSO 2017 DISTRIBUTION SUB.	in service	413-578-531	1/1/2017 0:00	12/31/2017 0:00	94,193.95		94,193.95
1 Electric	551077	55 Elec Distribution Substation	PD$ Various Dist Subs SPCC Oil 2017	completed	12175	7/1/2017 0:00	12/30/2017 0:00	204,452.13		204,452.13
1 Electric	551078	55 Elec Distribution Substation	Pontiac Add 23kV Feeder	completed	12178	1/27/2017 0:00	11/30/2017 0:00	141,660.44		141,660.44
1 Electric	551079	55 Elec Distribution Substation	Beauf.Centr: Add 115-12kV,28MVA Txf	open	8944	2/21/2017 0:00	3/30/2020 0:00	3,515.92		3,515.92

SOUTH CAROLINA ELECTRIC & GAS COMPANY
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AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	551080	55 Elec Distribution Substation	Garners Ferry 115-23kV Sub: Constr	open	11717	8/1/2017 0:00	3/1/2020 0:00	1,252.01		1,252.01
1 Electric	551081	55 Elec Distribution Substation	SC Ind Campus Acquire Sub Site	in service	12221	4/12/2017 0:00	12/31/2017 0:00	1,666.76		1,666.76
1 Electric	551082	55 Elec Distribution Substation	Smoaks 115/23KV Sub - Construct	open	11211	6/30/2017 0:00	7/30/2019 0:00	117.17		117.17
1 Electric	551083	55 Elec Distribution Substation	Charlotte St Replace Bus Diff Panel	open	12271	6/29/2017 0:00	2/28/2018 0:00	5,344.42		5,344.42
1 Electric	551086	55 Elec Distribution Substation	Substation Fiber Builds	open	12353	8/1/2017 0:00	3/31/2018 0:00	8,579.84		8,579.84
1 Electric	551088	55 Elec Distribution Substation	Cooper River 115-23kV Sub. #902	open	12483	12/1/2017 0:00	7/31/2018 0:00	718.92		718.92
1 Electric	570270	57 Elec Customer Substation	Clemson W.T. Sub: Construct 115/23	open	9126	6/30/2011 0:00	12/31/2017 0:00	877,813.84		877,813.84
1 Electric	570271	57 Elec Customer Substation	Clemson Wnd Turbine 115kV Sub: Site	open	9562	1/5/2011 0:00	9/29/2018 0:00	102,463.86		102,463.86
1 Electric	570319	57 Elec Customer Substation	2015 Grounding Upgrades Various Sub	open	11506	1/15/2015 0:00	12/1/2017 0:00	126,548.90		126,548.90
1 Electric	570324	57 Elec Customer Substation	Cola W Works Lake Murray: Recon bus	in service	11580	10/1/2015 0:00	1/8/2018 0:00	40,618.51		40,618.51
1 Electric	570329	57 Elec Customer Substation	Var C Subs Repl Mult XFMR Relays	open	11841	2/11/2016 0:00	7/31/2018 0:00	92,259.66		92,259.66
1 Electric	570333	57 Elec Customer Substation	Palmetto Rail 115-13.8kV Sub Site	open	12126	7/28/2016 0:00	12/31/2017 0:00	11,462.23		11,462.23
1 Electric	570336	57 Elec Customer Substation	Columbia Sewage 115kV - Add RTU	open	12137	9/12/2016 0:00	4/28/2018 0:00	3,166.27		3,166.27
1 Electric	570337	57 Elec Customer Substation	Palmetto Rail-Const 115-13.8kV Sub	open	11942	3/22/2017 0:00	10/30/2019 0:00	41,766.65		41,766.65
1 Electric	570340	57 Elec Customer Substation	Various Cust Subs SPCC Oil 2017	completed	12174	7/1/2017 0:00	12/30/2017 0:00	103,733.64		103,733.64
1 Electric	570343	57 Elec Customer Substation	Kronotex Sub: Add 115-13.8kV Txfmr	open	12232	6/1/2017 0:00	6/1/2018 0:00	77,082.12		77,082.12
1 Electric	570346	57 Elec Customer Substation	Jushi 115-13.8kV Sub - Construct	open	12122	7/27/2017 0:00	1/31/2019 0:00	10,450.77		10,450.77
1 Electric	607933	60 Elec Overhead Distribution Line	CLEMSON WIND 115KV LINE UNDERBUILD	open	10557	10/5/2015 0:00	12/31/2018 0:00	73,002.99		73,002.99
1 Electric	607991	60 Elec Overhead Distribution Line	BETTIS ACADEMY CON.	open	8936	3/19/2015 0:00	12/31/2017 0:00	58,256.42		58,256.42
1 Electric	608031	60 Elec Overhead Distribution Line	HAMPTON AVE 18012 CIRCUIT CORRECTIO	completed	3285	6/22/2016 0:00	12/31/2017 0:00	33,766.45		33,766.45
1 Electric	608042	60 Elec Overhead Distribution Line	WOODFIELD PARK 50322 CKT CORRECTION	open	4551	4/18/2016 0:00	9/1/2017 0:00	151,773.20		151,773.20
1 Electric	608045	60 Elec Overhead Distribution Line	GASTON 50392 TIE WITH COLUMBIA	completed	5208	8/5/2016 0:00	12/31/2017 0:00	752.47		752.47
1 Electric	608058	60 Elec Overhead Distribution Line	CKT INSPEC 2015 SUB 479/CKT 60282	completed	11142	8/15/2016 0:00	8/31/2016 6:54	238,782.95		238,782.95
1 Electric	608060	60 Elec Overhead Distribution Line	GILLSCREEK PHASE VI	completed	5136	9/1/2016 0:00	9/30/2016 13:05	450,691.68		450,691.68
1 Electric	608065	60 Elec Overhead Distribution Line	HAMPTON-VARNVILLE NEW TIE LINE	open	7163	8/1/2017 0:00	6/30/2018 0:00	1,517.27		1,517.27
1 Electric	608067	60 Elec Overhead Distribution Line	GREGG AVENUE RE-CONDUCTOR	completed	3284	6/1/2016 0:00	6/30/2016 10:05	266,853.29		266,853.29
1 Electric	608095	60 Elec Overhead Distribution Line	CIRCIT INSPECTION SUB 014/CKT 60192	open	3532	8/14/2017 0:00	8/31/2017 10:31	7,750.67		7,750.67
1 Electric	608097	60 Elec Overhead Distribution Line	CKT CORRECTION SUB 441/ CKT 60402	open	3532	6/5/2017 0:00	6/30/2017 11:24	11,445.43		11,445.43
1 Electric	608100	60 Elec Overhead Distribution Line	BELMONT CKT 810 - CORRECTIONS	open	3214	3/1/2016 0:00	3/31/2017 14:00	246,997.15		246,997.15
1 Electric	608101	60 Elec Overhead Distribution Line	ALLENDALE (278) CKT 40092 CORRECTIO	open	11142	6/1/2017 0:00	6/30/2017 11:24	37,864.43		37,864.43
1 Electric	608106	60 Elec Overhead Distribution Line	MIDDLEBURG 89412 CIRCUIT CORRECTION	completed	5138	7/17/2017 0:00	7/31/2017 10:17	49,241.06		49,241.06
1 Electric	608107	60 Elec Overhead Distribution Line	BUENA VISTA PHASE 1	open	4481	9/19/2016 0:00	7/1/2018 0:00	382,932.59		382,932.59
1 Electric	608109	60 Elec Overhead Distribution Line	SPRINGDALE 17412 RECONDUCTOR	open	5136	4/10/2017 0:00	4/30/2017 10:51	220,156.56		220,156.56
1 Electric	608112	60 Elec Overhead Distribution Line	OLD EASTOVER HWY RECONDUCTOR	open	5136	3/9/2017 0:00	3/31/2017 9:57	188,252.59		188,252.59
1 Electric	608115	60 Elec Overhead Distribution Line	CKT CORRECTIONS 2016 0686-71112 & 7	completed	9472	4/3/2017 0:00	4/30/2017 7:52	72,607.03		72,607.03
1 Electric	608128	60 Elec Overhead Distribution Line	JACKSON ST 21312 - CIRCUIT CORRECTI	open	5138	4/28/2017 0:00	4/30/2017 8:59	2,969.24		2,969.24
1 Electric	608129	60 Elec Overhead Distribution Line	RE$ PONTIAC 21102 EXIT FEEDER	completed	5159	9/28/2017 0:00	9/30/2017 8:48	47,825.03		47,825.03
1 Electric	608130	60 Elec Overhead Distribution Line	78502 CIP CORRECTION	completed	5138	9/12/2017 0:00	9/30/2017 10:01	10,450.03		10,450.03
1 Electric	608138	60 Elec Overhead Distribution Line	JACKSON ST 21212- CIRCUIT CORRECTIO	open	5138	1/24/2017 0:00	10/31/2017 0:00	2,498.66		2,498.66
1 Electric	608139	60 Elec Overhead Distribution Line	PARR 11232 CIRCUIT CORRECTION	completed	4181	4/3/2017 0:00	4/30/2017 14:52	105,155.91		105,155.91
1 Electric	608141	60 Elec Overhead Distribution Line	BATESBURG TRANSMISSION 23KV FEEDER	open	8936	2/20/2017 0:00	2/28/2018 0:00	35,109.65		35,109.65
1 Electric	608145	60 Elec Overhead Distribution Line	BATESBURG TRANSMISSION 23KV FEEDER	open	8936	8/7/2017 0:00	8/31/2017 7:24	1,090.35		1,090.35
1 Electric	608146	60 Elec Overhead Distribution Line	WINNSBORO TIE LINE PHASE 4	open	5159	7/3/2017 0:00	7/31/2017 12:51	105,501.76		105,501.76
1 Electric	608147	60 Elec Overhead Distribution Line	KINGSWOOD CKT 86012 - CORRECTIONS	open	3214	5/8/2017 0:00	5/31/2017 8:30	91,477.03		91,477.03
1 Electric	608151	60 Elec Overhead Distribution Line	RE$ SILVER BLUFF DOT PROJECT (3-17)	completed	4481	3/20/2017 0:00	3/31/2017 7:29	316,766.04		316,766.04
1 Electric	608152	60 Elec Overhead Distribution Line	SPRINGDALE 17412 RE-CONDUCTOR PHASE	completed	5136	4/10/2017 0:00	4/30/2017 10:53	60,913.49		60,913.49
1 Electric	608154	60 Elec Overhead Distribution Line	ST MATTHEWS CORRECTIONS	completed	9466	7/18/2017 0:00	7/31/2017 8:37	65,809.31		65,809.31
1 Electric	608155	60 Elec Overhead Distribution Line	ESTILL SOUTH (659) CKT40072 CORRREC	open	11142	9/25/2017 0:00	9/30/2017 8:43	4,678.77		4,678.77
1 Electric	608156	60 Elec Overhead Distribution Line	EE-PINEHILL SUB OH FEEDER#3 PH2 (17	completed	10506	5/22/2017 0:00	5/31/2017 8:09	158,694.64		158,694.64
1 Electric	608163	60 Elec Overhead Distribution Line	BELMONT 84112 CKT CORRECTION	open	4551	6/5/2017 0:00	6/30/2017 12:52	117,332.41		117,332.41
1 Electric	608169	60 Elec Overhead Distribution Line	GILLS CREEK CONVERSION VII	open	5136	10/2/2017 0:00	10/31/2017 6:14	144,344.24		144,344.24
1 Electric	679450	67 Elec UG Distribution Line	MT. PLEASANT TOWN HALL OH TO UG EST	open	527-417-189	7/1/2015 0:00	11/1/2017 0:00	(16,145.66)		(16,145.66)
1 Electric	679457	67 Elec UG Distribution Line	MONTICELLO ESTATES CABLE REPL	open	4494	5/1/2014 0:00	5/31/2018 0:00	163,698.36		163,698.36
1 Electric	679463	67 Elec UG Distribution Line	BRADLEY TERRACE CABLE REPLACEMENT	open	4494	6/2/2014 0:00	12/30/2017 0:00	76,890.13		76,890.13
1 Electric	679557	67 Elec UG Distribution Line	CROSSPOINT-UG PERM EXTENSION2EXISTI	completed	525-439-171	8/3/2015 0:00	8/31/2017 0:00	(7,055.76)		(7,055.76)
1 Electric	679562	67 Elec UG Distribution Line	FIVE NOTCH RD AREA CABLE REPL	open	8920	3/2/2015 0:00	12/31/2018 0:00	161,368.10		161,368.10
1 Electric	679589	67 Elec UG Distribution Line	RE$ QUAIL VALLEY LOOP 40-CABLE REPL	completed	11279	2/28/2017 0:00	12/31/2017 0:00	113,235.43		113,235.43

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DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	679707	67 Elec UG Distribution Line	SWEETWATER APTS. OH TO UG CONVERSIO	open	11270	7/18/2016 0:00	2/15/2018 0:00	(28,093.02)		(28,093.02)
1 Electric	679727	67 Elec UG Distribution Line	OAKHAVEN CABLE REPLAEMENT SHEET 3	open	527-417-189	8/16/2016 0:00	12/1/2017 0:00	91,826.15		91,826.15
1 Electric	679738	67 Elec UG Distribution Line	WHITE GABLES PHASE 4-A	open	525-439-171	8/22/2016 0:00	1/10/2018 0:00	46,775.12		46,775.12
1 Electric	679755	67 Elec UG Distribution Line	VILLIAGE GREEN ESTATES	open	525-476-162	8/2/2016 0:00	3/31/2017 0:00	63,781.20		63,781.20
1 Electric	679758	67 Elec UG Distribution Line	OYSTER POINT 3 PHASE LOOP COMPLETIO	completed	525-489-189	7/18/2016 0:00	2/1/2018 0:00	35,133.10		35,133.10
1 Electric	679762	67 Elec UG Distribution Line	DANIEL ISLAND PARCEL BB-5 & CC-6	completed	525-489-189	2/13/2017 0:00	2/28/2017 8:34	4,801.54		4,801.54
1 Electric	679763	67 Elec UG Distribution Line	OYSTER POINT PHASE 2C & 2D	completed	525-489-189	9/12/2016 0:00	9/30/2016 6:26	105,407.91		105,407.91
1 Electric	679765	67 Elec UG Distribution Line	PROXIMITY DRIVE 750 FEEDER EXTENSIO	completed	11272	5/1/2017 0:00	12/31/2017 0:00	(107,563.50)		(107,563.50)
1 Electric	679769	67 Elec UG Distribution Line	GRAND OAKS PHASES 5 AND 6-3 PHASE F	open	11272	5/1/2017 0:00	12/31/2017 0:00	(14,186.64)		(14,186.64)
1 Electric	679775	67 Elec UG Distribution Line	HUNT CLUB PHASE 6 - 3-PHASE UG FEED	completed	11272	12/5/2016 0:00	12/31/2016 12:48	170,854.01		170,854.01
1 Electric	679777	67 Elec UG Distribution Line	CAMBRIDGE SQUARE FEEDER RELOCATION	completed	10589	2/13/2017 0:00	2/28/2017 13:44	(55,835.67)		(55,835.67)
1 Electric	679780	67 Elec UG Distribution Line	LINEAGE LOGISTICS FEEDER	open	11273	8/8/2016 0:00	9/30/2016 0:00	166,796.03		166,796.03
1 Electric	679785	67 Elec UG Distribution Line	KLINE CITY CENTER	open	525-480-778	11/1/2016 0:00	6/30/2018 0:00	159,429.41		159,429.41
1 Electric	679786	67 Elec UG Distribution Line	CAROLINA BAY PHASE 21 SIMP	completed	6344	10/1/2016 0:00	10/31/2016 0:00	67,522.78		67,522.78
1 Electric	679788	67 Elec UG Distribution Line	CAROLINA BAY PHASE 21 NB	completed	525-490-190	10/10/2016 0:00	10/31/2016 9:46	96,223.13		96,223.13
1 Electric	679791	67 Elec UG Distribution Line	STRATTON BY THE SOUND PHASE 2	completed	525-489-189	6/6/2017 0:00	9/30/2017 10:11	15,345.00		15,345.00
1 Electric	679795	67 Elec UG Distribution Line	LEGENDS AT AZALEA SQUARE APARTMENTS	completed	525-439-171	9/1/2016 0:00	9/30/2016 0:00	122,655.79		122,655.79
1 Electric	679797	67 Elec UG Distribution Line	MUSC CEP METERING CABINETS UPGRADE	open	11232	4/3/2017 0:00	11/30/2017 0:00	(150,000.00)		(150,000.00)
1 Electric	679800	67 Elec UG Distribution Line	NETWORK PROTECTOR UPGRADES	open	10142	2/1/2017 0:00	2/28/2017 10:07	390,482.01		390,482.01
1 Electric	679801	67 Elec UG Distribution Line	GREENHURST CABLE REPLACEMENT 1/2	open	11082	12/1/2016 0:00	12/31/2016 13:22	166,309.66		166,309.66
1 Electric	679810	67 Elec UG Distribution Line	EE-CFT UG FEEDER PHASE 2 W/HWY LIGH	completed	525-439-171	2/27/2017 0:00	2/28/2017 9:28	24,852.68		24,852.68
1 Electric	679815	67 Elec UG Distribution Line	YMCA VAULT INSTALLATION	completed	10142	2/1/2017 0:00	2/28/2017 13:35	188,292.42		188,292.42
1 Electric	679817	67 Elec UG Distribution Line	DANIEL ISLAND PARCEL E PHASE 3 UG S	open	525-489-189	2/13/2017 0:00	2/28/2017 9:09	149,175.11		149,175.11
1 Electric	679818	67 Elec UG Distribution Line	SCDOT PORT ACCESS - OH TO UG KING S	completed	11230	3/1/2017 0:00	3/31/2017 8:20	158,076.03		158,076.03
1 Electric	679820	67 Elec UG Distribution Line	CROSSPOINT CP-V	completed	525-439-171	2/13/2017 0:00	2/28/2017 10:09	70,217.69		70,217.69
1 Electric	679828	67 Elec UG Distribution Line	BARR LAKES PHASE 2	completed	525-476-162	3/15/2017 0:00	3/31/2017 9:33	120,077.85		120,077.85
1 Electric	679830	67 Elec UG Distribution Line	LONGVIEW PHASE TWO	open	525-476-162	3/30/2017 0:00	3/31/2017 9:56	195,668.38		195,668.38
1 Electric	679833	67 Elec UG Distribution Line	HEATHER HILL PH 6	open	525-505-183	5/19/2017 0:00	5/31/2017 11:09	50,445.17		50,445.17
1 Electric	679837	67 Elec UG Distribution Line	CRESSWIND AT THE PONDS - PHASE 4	completed	525-439-171	5/30/2017 0:00	7/31/2017 12:51	(37,126.16)		(37,126.16)
1 Electric	679839	67 Elec UG Distribution Line	RHODENS ISLAND UG SVC - PARCEL FF-1	open	525-489-189	5/1/2017 0:00	11/1/2017 0:00	55,697.83		55,697.83
1 Electric	679841	67 Elec UG Distribution Line	BURTON ADDITIONAL FEEDER	open	11160	5/15/2017 0:00	5/31/2017 8:56	48,865.97		48,865.97
1 Electric	679842	67 Elec UG Distribution Line	511 MEETING ST APTS 3 PH UG SERVICE	open	525-488-188	6/5/2017 0:00	6/30/2017 8:05	43,576.66		43,576.66
1 Electric	679843	67 Elec UG Distribution Line	PORT ACCESS - MEETING/SPRUILL OH TO	completed	11230	5/29/2017 0:00	5/31/2017 11:27	108,124.45		108,124.45
1 Electric	679849	67 Elec UG Distribution Line	RIVER OAKS OFFICE BUILDING 3-PHASE	open	525-492-191	6/5/2017 0:00	6/30/2017 10:20	85,298.95		85,298.95
1 Electric	679853	67 Elec UG Distribution Line	BROOKLAND VILLAGE PROJECT	open	525-480-778	5/19/2017 0:00	5/31/2017 10:59	64,685.07		64,685.07
1 Electric	679855	67 Elec UG Distribution Line	TIMBER TRACE PHASE 1	completed	525-439-171	5/25/2017 0:00	5/31/2017 0:00	98,721.60		98,721.60
1 Electric	679857	67 Elec UG Distribution Line	RE$ WILDEWOOD OH LINE REMOVAL	completed	11281	6/6/2017 0:00	6/30/2017 12:53	17,343.69		17,343.69
1 Electric	679860	67 Elec UG Distribution Line	SAGE CREEK KNOLL AND BLUFF	completed	3233	7/5/2017 0:00	7/31/2017 14:33	103,911.52		103,911.52
1 Electric	679863	67 Elec UG Distribution Line	SHADOW MOSS PH 10	completed	525-436-170	7/13/2017 0:00	7/31/2017 0:00	1,471.96		1,471.96
1 Electric	679878	67 Elec UG Distribution Line	WRONG RD// AIRPORT RELOCATION	open	525-506-614	8/30/2017 0:00	8/31/2017 9:22	(68,410.00)		(68,410.00)
1 Electric	679880	67 Elec UG Distribution Line	PROJECT JACKSON FEEDER&SWITCHGEAR (	completed	3233	9/11/2017 0:00	9/30/2017 8:26	12,603.75		12,603.75
4 Common Ut	008018	960 Common Admin Overhead	EG 1018 Clearing Overhead	open	899-10-998	1/1/2001 0:00	1/1/2001 0:00	(13,894.39)		(13,894.39)
4 Common Ut	911435	900 Land and Structures-Common	Summerville Office Site Add-Faison	suspended	9624	3/1/2011 0:00	10/31/2018 0:00	5,194.52		5,194.52
4 Common Ut	911588	900 Land and Structures-Common	S'ville Office Site Add-Ellington	suspended	10368	10/31/2012 0:00	10/31/2018 0:00	7,873.09		7,873.09
4 Common Ut	911967	940 Misc Tools & Comm Eq-Common	Robinar A/C Recovery Machine	in service	3980	12/21/2016 0:00	6/21/2017 0:00	4,009.08	(4,009.08)	0.00
4 Common Ut	911968	900 Land and Structures-Common	METROPLEX-FLEX PKG. LOT RENOV.	open	12032	7/20/2016 0:00	7/31/2018 0:00	23,722.80		23,722.80
4 Common Ut	911974	910 Office Furniture &Eq-Common	HVAC Replacements - 2017 - Common	completed	4653	1/1/2017 0:00	2/28/2018 0:00	38,007.55		38,007.55
4 Common Ut	911996	940 Misc Tools & Comm Eq-Common	SRT-Dunbar Rd OPGW Build	open	12215	4/3/2017 0:00	5/1/2018 0:00	190,173.21		190,173.21
4 Common Ut	912005	940 Misc Tools & Comm Eq-Common	2017 AVL/VAN Units	in service	7608	7/15/2017 0:00	12/31/2017 0:00	97,642.17		97,642.17
4 Common Ut	912011	900 Land and Structures-Common	WARRENVILLE COMMERCIAL OFFICE	open	12487	9/5/2017 0:00	4/30/2018 0:00	15,523.66		15,523.66
4 Common Ut	980180	980 Common Intangible Plant	CIS High Frequency Caller Projects	open	10503	10/31/2015 0:00	5/31/2018 0:00	297,888.69		297,888.69
4 Common Ut	980181	980 Common Intangible Plant	CTI Replacement/Multi-Channel Apps	open	10503	10/31/2015 0:00	11/30/2017 0:00	596,451.40		596,451.40
4 Common Ut	980190	980 Common Intangible Plant	IVR Menu Redesign	open	10503	7/1/2016 0:00	12/31/2017 0:00	193,889.12		193,889.12
4 Common Ut	980192	980 Common Intangible Plant	Field Mobility Expansion Software	posted to CPR	10503	7/1/2017 0:00	8/30/2017 0:00	21,494.12		21,494.12
4 Common Ut	980193	980 Common Intangible Plant	CIS Optimization-Phase 2	open	10503	7/3/2017 0:00	6/30/2018 0:00	182,250.06		182,250.06
							Total excluding NND	**208,674,295.93**	**(5,224.87)**	**208,669,071.06**

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	170000	17 Nuclear UNIT 2 Production	VCS 2 & 3 WO	open	7466	1/1/2007 0:00	12/31/2019 0:00	4,520,183,565.46	(4,520,183,565.46)	0.00
1 Electric	450001	45 Elec Ovrhead Transmisn Line NND	PD$ VCS2-LMT 230kV Line #2	posted to CPR	8677	1/1/2009 0:00	6/1/2019 0:00	24,489,502.39		24,489,502.39
1 Electric	450002	45 Elec Ovrhead Transmisn Line NND	Project #0091F: Parr-Midway DC 115	in service	9112	1/1/2010 0:00	6/1/2019 0:00	836,048.59		836,048.59
1 Electric	450003	45 Elec Ovrhead Transmisn Line NND	PD$ Project 0090M1:Reterm Duke New*	in service	9115	2/1/2010 0:00	6/1/2019 0:00	1,039,732.32		1,039,732.32
1 Electric	450004	45 Elec Ovrhead Transmisn Line NND	Project #0090N3: Reterm Duke (BR)*	in service	9117	2/1/2010 0:00	8/31/2019 0:00	491,056.00		491,056.00
1 Electric	450007	45 Elec Ovrhead Transmisn Line NND	Project #0090N2 Reterm Ward 230kV	in service	9148	3/1/2010 0:00	6/1/2019 0:00	951,217.97		951,217.97
1 Electric	450008	45 Elec Ovrhead Transmisn Line NND	Project #0090N4 Reterm DennyTerrace	in service	9149	3/1/2010 0:00	6/1/2019 0:00	2,827,782.31		2,827,782.31
1 Electric	450013	45 Elec Ovrhead Transmisn Line NND	Project #0090N6 Temp Energize VCS#2	open	9490	9/1/2010 0:00	8/31/2019 0:00	205,767.05		205,767.05
1 Electric	450020	45 Elec Ovrhead Transmisn Line NND	VCS1-DT (VCS1-Winn Jct) 230 kV	in service	9586	2/1/2011 0:00	8/31/2019 0:00	2,145,381.57		2,145,381.57
1 Electric	450021	45 Elec Ovrhead Transmisn Line NND	PD$ VCS2-LMT 230 kV Line #1	in service	9588	2/1/2011 0:00	8/31/2019 0:00	3,097,213.89		3,097,213.89
1 Electric	450022	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #1	in service	9589	2/1/2011 0:00	8/31/2020 0:00	6,247,827.88		6,247,827.88
1 Electric	450023	45 Elec Ovrhead Transmisn Line NND	PD$ VCS2-St. George 230 kV Line #2	in service	9590	2/1/2011 0:00	8/31/2020 0:00	18,561,602.26		18,561,602.26
1 Electric	450025	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #1/#2	in service	9592	2/1/2011 0:00	8/31/2020 0:00	12,106,077.73		12,106,077.73
1 Electric	450026	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #1 & #2	open	9593	2/1/2011 0:00	8/31/2020 0:00	2,942,820.86		2,942,820.86
1 Electric	450028	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #2	open	9595	2/1/2011 0:00	8/31/2020 0:00	5,531,463.67		5,531,463.67
1 Electric	450031	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #1 & #2	open	9598	2/1/2011 0:00	8/31/2020 0:00	2,738,065.68		2,738,065.68
1 Electric	450033	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #1 & #2	open	9600	2/1/2011 0:00	8/31/2020 0:00	8,364,965.71		8,364,965.71
1 Electric	450035	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #1/#2	open	9602	2/1/2011 0:00	8/31/2020 0:00	20,059,247.60		20,059,247.60
1 Electric	450037	45 Elec Ovrhead Transmisn Line NND	PD$ VCS2-St George 230 kV Lin #1&#2	in service	9604	2/1/2011 0:00	8/31/2020 0:00	3,248,159.42		3,248,159.42
1 Electric	450039	45 Elec Ovrhead Transmisn Line NND	VCS2-St. George 230 kV Line #1 & #2	in service	9606	2/1/2011 0:00	8/31/2020 0:00	25,842,922.16		25,842,922.16
1 Electric	450043	45 Elec Ovrhead Transmisn Line NND	PD$ Parr-Winn 115 #1 Reloc Parr-Swi	in service	9659	6/1/2011 0:00	6/1/2019 0:00	1,251,117.23		1,251,117.23
1 Electric	450044	45 Elec Ovrhead Transmisn Line NND	PD$ Parr-Denny Terrace 115kV #14 Li	posted to CPR	9660	6/1/2011 0:00	6/1/2019 0:00	766,229.50		766,229.50
1 Electric	450052	45 Elec Ovrhead Transmisn Line NND	VCS1-Killian(VCS1-WinnJct)230 kV(C)	posted to CPR	9580	2/2/2011 0:00	8/31/2019 0:00	1,031,578.28		1,031,578.28
1 Electric	450053	45 Elec Ovrhead Transmisn Line NND	VCS1-Killian(WinnJct-Winn)230kV(C)	posted to CPR	9581	2/2/2011 0:00	6/1/2019 0:00	12,023,152.07		12,023,152.07
1 Electric	450054	45 Elec Ovrhead Transmisn Line NND	VCS1-Killian(Winn-Blythwd)230kV(C)	posted to CPR	9582	2/2/2011 0:00	6/1/2019 0:00	19,624,412.09		19,624,412.09
1 Electric	450055	45 Elec Ovrhead Transmisn Line NND	VCS1-Killian(Blywd-Killian)230kV(C)	posted to CPR	9583	2/2/2011 0:00	6/1/2019 0:00	11,892,742.62		11,892,742.62
1 Electric	450057	45 Elec Ovrhead Transmisn Line NND	VCS1-Killian 230kV Line: R/W (C)	posted to CPR	9615	2/2/2011 0:00	6/1/2019 0:00	4,012,716.05		4,012,716.05
1 Electric	450059	45 Elec Ovrhead Transmisn Line NND	PD$ Proj 94Q:Saluda Hyd-Newber115KV	posted to CPR	8710	11/14/2011 0:00	8/31/2020 0:00	4,262,313.95		4,262,313.95
1 Electric	450061	45 Elec Ovrhead Transmisn Line NND	PD$ McMeekin-Lake Murray Tra 115 kV	posted to CPR	8717	2/20/2012 0:00	8/31/2019 0:00	873,203.23		873,203.23
1 Electric	450062	45 Elec Ovrhead Transmisn Line NND	Saluda Hydro-LMT 115 kV	posted to CPR	8690	2/20/2012 0:00	8/31/2019 0:00	661,877.22		661,877.22
1 Electric	450064	45 Elec Ovrhead Transmisn Line NND	Denny Terrace-Lyles 230 kV	posted to CPR	8683	2/20/2012 0:00	8/31/2019 0:00	5,277,412.41		5,277,412.41
1 Electric	450069	45 Elec Ovrhead Transmisn Line NND	Candys-Sumter 230 kV	in service	8719	1/1/2013 0:00	8/31/2020 0:00	13,615,365.34		13,615,365.34
1 Electric	450071	45 Elec Ovrhead Transmisn Line NND	Saluda River-Lyles 230kV BLRA	posted to CPR	10676	11/1/2013 0:00	8/31/2019 0:00	7,538,045.61		7,538,045.61
1 Electric	450072	45 Elec Ovrhead Transmisn Line NND	St George-Summerville #1 230kV BLRA	open	8708	4/14/2014 0:00	6/1/2020 0:00	28,640,117.21		28,640,117.21
1 Electric	540002	54 Elec Transmission Substatn NND	PD$ St.George230/115kVSub-PurchasLa	completed	8671	1/19/2009 0:00	6/1/2020 0:00	334,044.42		334,044.42
1 Electric	540010	54 Elec Transmission Substatn NND	PD$ Killian-Add 1 230KV Termin-VCS1	completed	8676	3/15/2011 0:00	6/1/2019 0:00	491,498.40		491,498.40
1 Electric	540012	54 Elec Transmission Substatn NND	Saluda River 230/115kV Sub Site	completed	9954	8/31/2011 0:00	6/1/2019 0:00	3,355,688.23		3,355,688.23
1 Electric	540013	54 Elec Transmission Substatn NND	Parr Steam - Reterminate DT #14	completed	9956	8/1/2011 0:00	6/1/2019 0:00	371,767.18		371,767.18
1 Electric	540017	54 Elec Transmission Substatn NND	Lake Murray Trans: Add 230kV Term	completed	8679	3/1/2012 0:00	6/1/2019 0:00	443,635.50		443,635.50
1 Electric	540018	54 Elec Transmission Substatn NND	PD$ Denny Terr Repl Relays on VCS1	completed	10095	6/25/2012 0:00	6/1/2019 0:00	84,324.90		84,324.90
1 Electric	540020	54 Elec Transmission Substatn NND	PD$ Denny Terr Repl Relays on VCS2	completed	10096	6/25/2012 0:00	6/1/2019 0:00	79,183.25		79,183.25
1 Electric	540022	54 Elec Transmission Substatn NND	PD$ Pineland Repl Relays on VCS1 Li	completed	10098	6/25/2012 0:00	6/1/2019 0:00	78,593.66		78,593.66
1 Electric	540023	54 Elec Transmission Substatn NND	PD$ Ward Repl Relays on VCS2 Line	completed	10099	6/25/2012 0:00	6/1/2019 0:00	84,072.23		84,072.23
1 Electric	540026	54 Elec Transmission Substatn NND	Denny Terr: Repl Rlys on Parr #14	completed	10104	7/30/2012 0:00	6/1/2019 0:00	109,357.09		109,357.09
1 Electric	540028	54 Elec Transmission Substatn NND	St George 230kV Sw Sta - Construct	completed	8704	1/30/2013 0:00	8/31/2020 0:00	7,429,345.14		7,429,345.14
1 Electric	540029	54 Elec Transmission Substatn NND	Saluda River 230/115kV: Construct	completed	10675	5/1/2013 0:00	8/31/2019 0:00	12,769,501.37		12,769,501.37
1 Electric	540030	54 Elec Transmission Substatn NND	Saluda Hydro Sub: Upgrade 115kV Bus	open	10446	1/1/2014 0:00	4/1/2018 0:00	696,529.24		696,529.24
1 Electric	540031	54 Elec Transmission Substatn NND	PD$ Lake Mur Sub:Upg Sal Hydro line	completed	10623	8/21/2013 0:00	6/1/2019 0:00	187,617.42		187,617.42
1 Electric	540032	54 Elec Transmission Substatn NND	Various 115kv PRCB's: Upgrade	completed	8691	11/11/2013 0:00	4/1/2020 0:00	838,177.13		838,177.13
1 Electric	540034	54 Elec Transmission Substatn NND	PD$ Canadys:Upgd Bus & St.George Te	completed	10965	2/10/2014 0:00	9/1/2019 0:00	72,305.30		72,305.30
1 Electric	540035	54 Elec Transmission Substatn NND	PD$ Lyles 230KV Substation #2202	completed	10987	3/18/2014 0:00	6/1/2019 0:00	277,777.69		277,777.69
1 Electric	540036	54 Elec Transmission Substatn NND	Denny Terrace 230KV Sub. #2045	completed	10986	4/1/2014 0:00	8/31/2019 0:00	349,595.39		349,595.39
1 Electric	540040	54 Elec Transmission Substatn NND	Various Subs-Upgrd 115kV Bkrs	open	8707	3/18/2016 0:00	12/1/2020 0:00	146,410.48		146,410.48
1 Electric	540041	54 Elec Transmission Substatn NND	Summerville 230kV Sub. #2071	open	11285	6/1/2016 0:00	5/1/2018 0:00	324,935.76		324,935.76
1 Electric	168003	168 ElecTransmission - BLRA-VCS1	Parr Safeguard 115 kV	in service	10052	6/6/2011 0:00	8/31/2019 0:00	2,699,153.72		2,699,153.72
1 Electric	168008	168 ElecTransmission - BLRA-VCS1	Parr 115kV Safeguard - Raise @ VCS	in service	10450	11/15/2012 0:00	6/1/2020 0:00	851,869.67		851,869.67
1 Electric	168100	168 ElecTransmission - BLRA-VCS1	VCS#1-Add Term & Repl 2 Disc Sw.	completed	10074	6/1/2010 0:00	6/1/2019 0:00	3,844,145.94		3,844,145.94

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DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

RESPONSE NO. 1-79

Business Segment	Work Order	Work Order Group	Work Order Description	Work Order Status	Funding Project Number	Est Start Date	Est Complete Date	Amount (per books)	Proforma Closings	Amount (per FERC)
1 Electric	168101	168 ElecTransmission - BLRA-VCS1	VCS#1-Upgd 2 Terms & Repl Disc Sw	completed	9198	6/29/2010 0:00	6/1/2019 0:00	4,273,802.62		4,273,802.62
1 Electric	168102	168 ElecTransmission - BLRA-VCS1	VC Summer Sub #2561-Upgrade PrCB's	in service	10077	10/1/2007 0:00	6/1/2019 0:00	9,239,007.00		9,239,007.00
1 Electric	168103	168 ElecTransmission - BLRA-VCS1	VCS1 Add Pineland Terminal fr VCS1	completed	10076	1/1/2008 0:00	6/1/2019 0:00	2,196,076.20		2,196,076.20
1 Electric	168104	168 ElecTransmission - BLRA-VCS1	NC$ VCS 1 Upgrade Terminal 8832	completed	9415	5/1/2012 0:00	6/1/2020 0:00	1,264,252.92		1,264,252.92
1 Electric	168105	168 ElecTransmission - BLRA-VCS1	NC$ VCS1, Bus1:SCPSA Upg8852 Ad9322	completed	10080	5/23/2012 0:00	6/1/2019 0:00	2,973,305.31		2,973,305.31
1 Electric	168106	168 ElecTransmission - BLRA-VCS1	VCS1, Bus 1: SCPSA repl 8863 & LA's	completed	10081	5/24/2012 0:00	6/1/2019 0:00	461,793.94		461,793.94
1 Electric	168107	168 ElecTransmission - BLRA-VCS1	VCS1 Upgr 230kv 8902 & 8932	in service	9414	7/1/2013 0:00	6/1/2020 0:00	3,444,618.82		3,444,618.82
1 Electric	168800	168 ElecTransmission - BLRA-VCS1	Project#0090H:VCS #2 Tie to VCS #1	in service	10072	1/1/2009 0:00	6/1/2019 0:00	1,093,032.12		1,093,032.12
1 Electric	168801	168 ElecTransmission - BLRA-VCS1	Project #0090J:VCS#2 to VCS#1Bus#3	in service	10075	3/1/2010 0:00	6/1/2019 0:00	762,519.19		762,519.19
1 Electric	168802	168 ElecTransmission - BLRA-VCS1	VCS3 Tie to VCS1 Bus #1: Bus Tie #1	completed	10078	10/1/2011 0:00	6/1/2020 0:00	674,802.30		674,802.30
							Total NND	**4,835,683,442.86**	**(4,520,183,565.46)**	**315,499,877.40**
								5,044,357,738.79	**(4,520,188,790.33)**	**524,168,948.46**

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DEPRECIATION EXPENSE
AS OF SEPTEMBER 30, 2017
FOR TEST YEAR ENDED SEPTEMBER 30, 2017

RESPONSE NO. 1- 84

ELECTRIC FUNCTIONS	**PRESENT RATES**	**ACTUAL PROVISIONS October 2016 to September 2017**
STEAM		
FH CANADYS 311 - STRUCTURES	0.00%	-
FH CANADYS 312 - BOILER PLANT EQUIP	0.00%	-
FH CANADYS 314 - TURBOGEN UNIT	0.00%	-
FH CANADYS 315 - ACCESS ELECT EQUIP	0.00%	-
FH CANADYS 316 - MISC ELECT EQUIP	0.00%	-
FH COPE 311 - STRUCTURES	1.61%	1,322,613
FH COPE 312 - BOILER PLANT EQUIP	2.95%	7,833,581
FH COPE 312 - BOILER PLANT EQUIP (SCRUBBER)	2.95%	2,062,396
FH COPE 314 - TURBOGEN UNIT	2.01%	1,744,013
FH COPE 315 - ACCESS ELECT EQUIP	1.48%	360,481
FH COPE 316 - MISC ELECT EQUIP	2.08%	234,097
FH COPE 316 - MISC ELECT EQUIP (SCRUBBER)	2.08%	12,864
FH CENTRAL LAB 311 - STRUCTURES	4.26%	150,010
FH CENTRAL LAB 315 - ACCESS ELECT EQ	2.50%	1,464
FH CENTRAL LAB 316 - MISC ELECT EQUIP	6.09%	169,776
FH MCMEEKIN 311 - STRUCTURES	5.05%	959,370
FH MCMEEKIN 312 - BOILER PLANT EQUIP	6.73%	7,399,269
FH MCMEEKIN 314 - TURBOGEN UNIT	5.90%	2,250,838
FH MCMEEKIN 315 - ACCESS ELECT EQUIP	4.57%	533,229
FH MCMEEKIN 316 - MISC ELECT EQUIP	4.55%	210,817
FH URQUHART 311 - STRUCTURES	4.04%	679,380
FH URQUHART 312 - BOILER PLANT EQUIP	9.59%	2,180,426
FH URQUHART 314 - TURBOGEN UNIT	5.17%	3,031,333
FH URQUHART 315 - ACCESS ELECT EQUIP	4.29%	599,349
FH URQUHART 316 - MISC ELECT EQUIP	6.68%	327,781
FH WATEREE 311 - STRUCTURES	3.32%	1,839,789
FH WATEREE 311 - STR - (SCR) PND&LDFL	3.32%	2,690,292
FH WATEREE 312 - BOILER PLANT EQUIP	3.97%	14,480,443
FH WATEREE 312 - BOILER PLANT EQ-(SCR)	3.97%	8,508,044
FH WATEREE 314 - TURBOGEN UNIT	3.06%	4,356,054
FH WATEREE 315 - ACCESS ELECT EQUIP	2.72%	796,892
FH WATEREE 316 - MISC ELECT EQUIP	2.67%	173,525
JASPER		
FH JASPER 312 - BOILER PLANT EQUIP	3.41%	11,992
FH JASPER 314 - TURBOGEN UNIT	2.63%	2,629,137
FH JASPER 315 - ACCESS ELECT EQUIP	1.77%	117,276
FH JASPER 316 - MISC ELECT EQUIP	2.44%	11,498
TOTAL STEAM (EXCLUDING KAPSTONE)		**67,678,029**
NUCLEAR		
NU VC SUMMER 321 - STRUCTURES	1.07%	3,281,523
NU VC SUMMER 322 - REACTOR PLANT EQ	1.36%	7,394,151
NU VC SUMMER 323 - TURBOGEN UNIT	2.20%	2,564,157
NU VC SUMMER 324 - ACCESS ELECT EQ	1.18%	1,345,395
NU VC SUMMER 325 - MISC POWER PLT EQ	3.95%	6,486,897
TOTAL NUCLEAR		**21,072,123**

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DEPRECIATION EXPENSE
AS OF SEPTEMBER 30, 2017
FOR TEST YEAR ENDED SEPTEMBER 30, 2017

ELECTRIC FUNCTIONS	**PRESENT RATES**	**ACTUAL PROVISIONS October 2016 to September 2017**
HYDRO		
FH FAIRFIELD 331 - STRUCTURES	0.86%	312,178
FH FAIRFIELD 332 - RESERVOIRS	0.81%	605,124
FH FAIRFIELD 333 - WATERWHEEL	1.36%	917,767
FH FAIRFIELD 334 - ACCESS ELECT EQUIP	2.06%	396,505
FH FAIRFIELD 335 - MISC POWER PLANT	1.70%	110,743
FH FAIRFIELD 336 - ROADS, RR & BRIDGES	1.25%	16,608
FH NEAL SHOALS 331 - STRUCTURES	1.14%	9,058
FH NEAL SHOALS 332 - RESERVOIRS	2.36%	85,196
FH NEAL SHOALS 333 - WATERWHEEL	1.52%	52,908
FH NEAL SHOALS 334 - ACCESS ELECT EQ	1.73%	7,486
FH NEAL SHOALS 335 - MISC POWER PLT	1.39%	5,078
FH NEAL SHOALS 336 - ROADS, RR & BRID	0.64%	12
FH PARR 331 - STRUCTURES	2.13%	40,421
FH PARR 332 - RESERVOIRS	1.38%	67,260
FH PARR 333 - WATERWHEEL	1.95%	54,720
FH PARR 334 - ACCESS ELECT EQUIP	1.88%	36,852
FH PARR 335 - MISC POWER PLANT	1.83%	8,819
FH PARR 336 - ROADS, RR & BRIDGES	0.78%	972
FH SALUDA 331 - STRUCTURES	1.29%	99,605
FH SALUDA 332 - RESERVOIRS	0.87%	189,915
FH SALUDA 332.5 - HYDRO BACKUP DAM	0.34%	1,131,672
FH SALUDA 333 - WATERWHEEL	1.28%	132,649
FH SALUDA 334 - ACCESS ELECT EQUIP	1.58%	41,741
FH SALUDA 335 - MISC POWER PLANT	1.72%	34,917
FH SALUDA 336 - ROADS, RR & BRIDGES	0.89%	2,076
FH STEVENS CREEK 331 - STRUCTURES	0.89%	26,618
FH STEVENS CREEK 332 - RESERVOIRS	0.87%	55,944
FH STEVENS CREEK 333 - WATERWHEEL	0.98%	27,460
FH STEVENS CREEK 334 - ACCESS EL EQ	1.13%	12,192
FH STEVENS CREEK 335 - MISC POWER PLT	1.12%	12,012
FH STEVENS CREEK 336 - ROADS, RR & BR	1.04%	1,344
TOTAL HYDRO		**4,495,852**

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DEPRECIATION EXPENSE
AS OF SEPTEMBER 30, 2017
FOR TEST YEAR ENDED SEPTEMBER 30, 2017

ELECTRIC FUNCTIONS	PRESENT RATES	ACTUAL PROVISIONS October 2016 to September 2017
OTHER PRODUCTION		
FH BOEING SOLAR PROJECT 341	5.44%	6,372
FH BOEING SOLAR PROJECT 344	5.65%	397,944
FH BOEING SOLAR PROJECT 345	5.68%	124,800
FH BOEING SOLAR PROJECT 346	5.31%	936
FH WILLIAMS GT 341 - STRUCTURES	2.08%	12,806
FH WILLIAMS GT 342 - FUEL HOLDERS	0.94%	1,500
FH WILLIAMS GT 343 - PRIME MOVERS	1.89%	119,827
FH WILLIAMS GT 344 - GENERATORS	0.77%	588
FH WILLIAMS GT 345 - ACC ELECT EQ	2.18%	6,660
FH WILLIAMS GT 346 - MISC ELECT EQ	1.56%	1,824
FH FABER PLACE GT 341 - STRUCTURES	0.00%	-
FH FABER PLACE GT 342- FUEL HOLDERS	0.00%	-
FH FABER PLACE GT 343 -PRIME MOVERS	0.00%	-
FH FABER PLACE GT 344 - GENERATORS	0.00%	-
FH FABER PLACE GT 345 - ACC ELT EQ	0.00%	-
FH FABLE PLACE GT 346 - MISC PLT EQ	0.00%	-
FH BURTON GT 341 - STRUCTURES	0.00%	-
FH BURTON GT 342 - FUEL HOLDERS	0.00%	-
FH BURTON GT 343 - PRIME MOVERS	0.00%	-
FH BURTON GT 344 - GENERATORS	0.00%	-
FH BURTON GT 345 - ACC ELECT EQUIP	0.00%	-
FH BURTON GT 346 - MISC ELECT EQUIP	0.00%	-
FH COIT GT 341 - STRUCTURES	1.80%	3,276
FH COIT GT 342 - FUEL HOLDERS	1.74%	9,888
FH COIT GT 343 - PRIME MOVERS	2.36%	28,529
FH COIT GT 344 - GENERATORS	0.64%	22,404
FH COIT GT 345 - ACC ELECT EQ	3.50%	21,926
FH COIT GT 346 - MISC ELECT EQ	1.75%	2,700
FH HAGOOD GT 341 - STRUCTURES	1.26%	44,449
FH HAGOOD GT 342 - FUEL HOLDERS	0.86%	7,249
FH HAGOOD GT 343 - PRIME MOVERS	2.24%	546,814
FH HAGOOD GT 344 - GENERATORS	1.08%	65,595
FH HAGOOD GT 345 - ACC ELECT EQ	1.56%	43,902
FH HAGOOD GT 346 - MISC ELECT EQ	2.84%	10,456
FH HAGOOD ICT U5 341 - STRUCTURES	2.32%	8,124
FH HAGOOD ICT U5 342 - F/HOLDERS	2.63%	8,856
FH HAGOOD ICT U5 343 - PRIME MOVERS	2.07%	103,402
FH HAGOOD ICT U5 344 - GENERATORS	0.00%	-
FH HAGOOD ICT U5 345 - ACC ELEC EQ	2.86%	61,454
FH HAGOOD ICT U5 346 - MISC PWR PL	0.00%	-
FH HAGOOD ICT U6 341 - STRUCTURES	2.32%	15,852
FH HAGOOD ICT U6 342 - F/HOLDERS	2.63%	11,016
FH HAGOOD ICT U6 343 - PRIME MOVERS	2.12%	135,161
FH HAGOOD ICT U6 344 - GENERATORS	2.11%	72
FH HAGOOD ICT U6 345 - ACC ELEC EQ	2.76%	90,699
FH HAGOOD ICT U6 346 - MISC PWR PL	2.58%	1,632

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DEPRECIATION EXPENSE
AS OF SEPTEMBER 30, 2017
FOR TEST YEAR ENDED SEPTEMBER 30, 2017

ELECTRIC FUNCTIONS	**PRESENT RATES**	**ACTUAL PROVISIONS October 2016 to September 2017**
FH HARDEEVILLE GT 341 - STRUCTURES	13.11%	7,548
FH HARDEEVILLE GT 342 - FUEL HOLDERS	8.81%	47,076
FH HARDEEVILLE GT 343 - PRIME MOVERS	8.29%	66,216
FH HARDEEVILLE GT 344 - GEN	15.62%	290,976
FH HARDEEVILLE GT 345 - ACC ELECT EQ	20.02%	56,652
FH HARDEEVILLE GT 346 - MISC ELECT EQ	27.75%	20,592
FH PARR GT 341 - STRUCTURES	3.29%	29,410
FH PARR GT 342 - FUEL HOLDERS	2.61%	14,748
FH PARR GT 343 - PRIME MOVERS	7.16%	320,313
FH PARR GT 344 - GENERATORS	1.10%	37,152
FH PARR GT 345 - ACC ELECT EQ	3.65%	39,828
FH PARR GT 346 - MISC ELECT EQ	3.71%	7,380
FH SOLAR FARM 341	5.44%	87
FH SOLAR FARM 346	5.31%	9
FH URQ GT #1 & #2 341 - STRUCTURES	3.06%	38,916
FH URQ GT #1 & #2 342 - FUEL HOLDERS	2.74%	5,184
FH URQ GT #1 & #2 343 - PRIME MOVERS	3.79%	25,040
FH URQ GT #1 & #2 344 - GENERATORS	2.20%	74,847
FH URQ GT #1 & #2 345 - ACC ELECT EQ	4.26%	8,460
FH URQ GT #1 & #2 346 - MISC ELECT EQ	3.39%	3,365
FH URQ GT #3 341 - STRUCTURES	6.48%	22,920
FH URQ GT #3 342 - FUEL HOLDERS	3.82%	300
FH URQ GT #3 343 - PRIME MOVERS	7.54%	17,647
FH URQ GT #3 344 - GENERATORS	2.83%	66,363
FH URQ GT #3 345 - ACC ELECT EQ	6.09%	3,432
FH URQ GT #4 341 - STRUCTURES	0.83%	2,628
FH URQ GT #4 342 - FUEL HOLDERS	0.60%	1,988
FH URQ GT #4 343 - PRIME MOVERS	3.77%	120,022
FH URQ GT #4 344 - GENERATORS	1.36%	271,066
FH URQ GT #4 345 - ACC ELECT EQ	2.23%	10,548
FH URQ GT #4 346 - MISC ELECT EQ	2.34%	1,214
FH URQ GT #5 & #6 341 - STRUCTURES	1.80%	94,024
FH URQ GT #5 & #6 342 - FUEL HOLDERS	1.76%	63,516
FH URQ GT #5 & #6 3425 - FUEL HOLDERS	0.00%	-
FH URQ GT #5 & #6 343 - PRIME MOVERS	3.51%	7,865,868
FH URQ GT #5 & #6 344 - PRIME MOVERS	1.79%	239,556
FH URQ GT #5 & #6 345 - ACC ELECT EQ	2.23%	381,522
FH URQ GT #5 & #6 3460 - ACC ELECT EQ	2.47%	3,744
FH JASPER GT 341 - STRUCTURES	2.16%	608,913
FH JASPER GT 342 - FUEL HOLDERS	2.66%	252
FH JASPER GT 343 - PRIME MOVERS	3.54%	10,786,131
FH JASPER GT 344 - GENERATORS	1.74%	569,610
FH JASPER GT 345 - ACC ELECT EQ	2.47%	772,350
FH JASPER GT 346 - MISC ELECT EQ	2.90%	21,992
TOTAL OTHER PRODUCTION		**24,936,118**

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DEPRECIATION EXPENSE
AS OF SEPTEMBER 30, 2017
FOR TEST YEAR ENDED SEPTEMBER 30, 2017

ELECTRIC FUNCTIONS	**PRESENT RATES**	**ACTUAL PROVISIONS October 2016 to September 2017**
TRANSMISSION		
FH 353 STATION EQUIPMENT	1.81%	99,800
FH BURTON GT 353 STEPUP XFMR	0.00%	-
FH BUSHY PARK GT 353 STEPUP XFMR	1.97%	2,964
FH CANADYS 353 STEPUP XFMR	0.00%	-
FH COIT GT 353 STEPUP XFMR	1.04%	1,224
FH COPE 353 STEPUP XFMR	2.18%	131,232
FH FABER PLACE GT 353 STEPUP XFMR	0.00%	-
FH FAIRFIELD HYD GT 353 STEPUP XFMR	1.85%	142,428
FH HAGOOD GT 353 STEPUP XFMR	1.31%	34,044
FH HARDEEVILLE GT 353 STEPUP XFMR	1.60%	1,896
FH JASPER 353 STEPUP XFMR	2.21%	422,124
FH MCMEEKIN 353 STEPUP XFMR	2.36%	19,332
FH PARR HYDRO 353 STEPUP XFMR	2.53%	10,056
FH SALUDA HYDRO 353 STEPUP XFMR	1.51%	8,988
FH STEVENS CR HYDRO 353 STEPUP XFMR	1.92%	7,752
FH STEVENS CR 353 STEPUP XFMR	0.00%	-
FH URQUHART 353 STEPUP XFMR	1.88%	25,680
FH URQUHART GT 353 STEPUP XFMR	2.70%	28,260
FH WATEREE 353 STEPUP XFMR	4.21%	234,540
FH WILLIAMS 353 STEPUP XFMR	2.21%	39,972
FH WILLIAMS 353 STEPUP XFMR-GSU	2.21%	184,548
IN FAIRFIELD 353 - STATION EQUIPMENT	0.40%	5,005
IN NEAL SHOALS HYDRO 354 - 356	0.22%	171
IN PARR HYDRO 352 - 353 - STATION EQ	2.29%	11,868
IN SALUDA HYDRO 352 - 353	2.30%	204,668
IN STEVENS CREEK HYDRO 352 - 353	4.58%	213,132
IN 352 - STRUCTURES & IMPROVEMENTS	1.78%	61,389
IN 353 - STATION EQUIPMENT	1.81%	6,427,735
IN 353.8 - STATION EQUIPMENT-LEASEHOLD	5.90%	88,348
IN 354 - TOWERS & FIXTURES	1.37%	73,368
IN 355 - POLES & FIXTURES	3.33%	13,009,984
IN 355.8 - POLES & FIXTURES-LEASEHOLD	5.74%	108,652
IN 356.1 - OVERHEAD CONDUCTORS/DEVICES	2.50%	75,142
IN 356.2 - OVERHEAD CONDUCTORS/DEVICES-FIBER OPTIC	2.47%	163,464
IN 356.8 - OVERHEAD CONDUCTORS/DEVICES-LEASEHOLD	11.57%	5,406,670
IN 357 - UNDERGROUND CONDUIT	1.62%	326,593
IN 358 - UNDERGROUND CONDUCTORS/DEV	1.96%	1,143,221
IN 359 - ROADS & TRAILS	1.41%	1,044
NUCLEAR TRANSMISSION		
NU VC SUMMER 352 - STRUCTURES	1.52%	5,016
NU VC SUMMER 353 - STATION EQUIPMENT	3.28%	592,685
NU VC SUMMER 353 - STEPUP XFMR	3.62%	497,604
TOTAL TRANSMISSION		**29,810,599**

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DEPRECIATION EXPENSE
AS OF SEPTEMBER 30, 2017
FOR TEST YEAR ENDED SEPTEMBER 30, 2017

ELECTRIC FUNCTIONS	**PRESENT RATES**	**ACTUAL PROVISIONS October 2016 to September 2017**
DISTRIBUTION: SUBSTATIONS		
IN 362 - STATION EQUIPMENT	1.93%	7,502,848
IN 362.8 - STATION EQUIPMENT-LEASEHOLD	5.52%	203,665
		7,706,513
DISTRIBUTION		
IN 361 - STRUCTURES & IMPROVEMENTS	1.70%	82,188
IN 361.8 - STRUCTURES & IMPROVEMENTS-LEASEHOLD	11.30%	7,524
RE 364 - POLES, TOWERS & FIXTURES	3.12%	14,322,632
RE 365 - OVERHEAD CONDUCTORS/DEVICES	1.68%	8,344,730
RE 366 - NETWORK	1.46%	111,888
RE 366 - UNDERGROUND CONDUIT	1.46%	2,099,862
RE 367 - NETWORK	1.92%	195,876
RE 367 - UNDERGROUND CONDUCTORS/DEV	1.92%	8,454,693
RE 368 - LINE TRANSFORMERS	2.04%	9,561,745
RE 369 - SERVICES - OVERHEAD	2.42%	2,573,852
RE 3691 - SERVICES - UNDERGROUND	1.50%	2,682,322
RE 370 - METERS	2.62%	620,210
RE 3703 -AMR- METERS	9.59%	6,778,793
RE 3704 -AMI- METERS	8.64%	1,415,527
RE 3705 -AMI- METERS-DER	8.64%	-
RE 373 - STREET LIGHTING & SIGNAL SYS	2.89%	9,162,636
TOTAL DISTRIBUTION W/O SUBSTATIONS		**66,414,478**
GENERAL		
FH 3901 GENERAL - STRUCTURES & IMPROVE	1.91%	1,820
FH 3902 GENERAL - STRUCTURES & IMPROVE	2.27%	336
FH 390.8 GENERAL - STRUCTURES - LEASEHOLD	0.53%	-
FH 390.9 GENERAL - STRUCTURES - WAREHOUSE LEASEHOLD	2.79%	-
FH 3911 GENERAL - OFFICE FURN & EQUIP	5.25%	2,966
FH 3912 GENERAL - EDP EQUIPMENT	20.00%	657
FH 3913 GENERAL - DATA HANDLING EQUIP	6.43%	2,856
FH 3914 GENERAL - EDP EQUIPMENT	0.00%	-
FH 393 GENERAL - STORES EQUIPMENT	3.52%	-
FH 3941 GENERAL - TOOLS SHOP & GARAGE	5.33%	-
FH 3942 GENERAL - TOOLS SHOP & GARAGE	3.10%	-
FH 3943 GENERAL - TOOLS SHOP & GARAGE	6.78%	-
FH 3944 GENERAL - TOOLS SHOP & GARAGE	6.90%	-
FH 3951 GENERAL - LABORATORY EQUIP	1.86%	-
FH 3952 GENERAL - LABORATORY EQUIP	5.34%	-
FH 3953 GENERAL - LABORATORY EQUIP	5.01%	21,801
FH 397 GENERAL - COMMUNICATION EQUIP	5.09%	49,564
FH 398 GENERAL - MISCELLANEOUS EQUIP	3.75%	36,644
NU 390 STRUCTURES AND IMPROVEMENTS	0.00%	-
NU 3911 GENERAL - OFFICE FURN & EQUIP (FD)	0.00%	-
NU 3912 GENERAL - EDP EQUIPMENT	0.00%	-
NU 3913 GENERAL - DATA HANDLING EQUIP	0.00%	-
NU 393 STORES EQUIPMENT	0.00%	-
NU 394 TOOLS, SHOP & GARAGE EQ	0.00%	-
NU 395 LABORATORY EQUIPMENT	0.00%	-
NU 397 GENERAL - COMMUNICATION EQUIP	0.00%	-
NU 398 MISCELLANEOUS EQUIPMENT	0.00%	-
IN 3901 GENERAL - STRUCTURES & IMPROVE	1.91%	492,521
IN 39011 GENERAL - STRUCTURES & IMPROVE-TOC	1.91%	8,262
IN 3902 GENERAL - STRUCTURES & IMPROVE	2.27%	23,352
IN 390.8 GENERAL - STRUCTURES - LEASEHOLD	0.53%	-
IN 390.9 GENERAL - STRUCTURES - WAREHOUSE LEASEHOLD	2.79%	-

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
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ELECTRIC FUNCTIONS	**PRESENT RATES**	**ACTUAL PROVISIONS October 2016 to September 2017**
IN 3911 GENERAL - OFFICE FURN & EQUIP	5.25%	216,860
IN 3912 GENERAL - EDP EQUIPMENT	20.00%	858,825
IN 3913 GENERAL - DATA HANDLING EQUIP	6.43%	4,704
IN 3914 GENERAL - EDP EQUIPMENT	0.00%	-
IN 393 GENERAL - STORES EQUIPMENT	3.52%	1,308
IN 3941 GENERAL - TOOLS SHOP & GARAGE	5.33%	12,157
IN 3942 GENERAL - TOOLS SHOP & GARAGE	3.10%	26,307
IN 3943 GENERAL - TOOLS SHOP & GARAGE	6.78%	9,081
IN 3944 GENERAL - TOOLS SHOP & GARAGE	6.90%	255
IN 3951 GENERAL - LABORATORY EQUIP	1.86%	11,670
IN 3952 GENERAL - LABORATORY EQUIP	5.34%	12,677
IN 3953 GENERAL - LABORATORY EQUIP	5.01%	153,325
IN 397 GENERAL - COMMUNICATION EQUIP	5.09%	93,285
IN 398 GENERAL - MISCELLANEOUS EQUIP	3.75%	73,476
RE 3901 GENERAL - STRUCTURES & IMPROVE	1.91%	1,092,030
RE 39011 Struct & Imp-N. Cha E Ops	1.91%	288,480
RE 3902 GENERAL - STRUCTURES & IMPROVE	2.27%	210,474
RE 390.8 GENERAL - STRUCTURES - LEASEHOLD	0.53%	768
RE 390.9 GENERAL - STRUCTURES - WAREHOUSE LEASEHOLD	2.79%	3,096
RE 3911 GENERAL - OFFICE FURN & EQUIP	5.25%	206,941
RE 3912 GENERAL - EDP EQUIPMENT	20.00%	315,933
RE 3913 GENERAL - DATA HANDLING EQUIP	6.43%	12,050
RE 3914 GENERAL - EDP EQUIPMENT	0.00%	-
RE 3919 GENERAL - LEASEHOLD FURNISHINGS	0.00%	-
RE 393 GENERAL - STORES EQUIPMENT	3.52%	4,503
RE 3941 GENERAL - TOOLS SHOP & GARAGE	5.33%	15,003
RE 3942 GENERAL - TOOLS SHOP & GARAGE	3.10%	58,887
RE 3943 GENERAL - TOOLS SHOP & GARAGE	6.78%	7,002
RE 3944 GENERAL - TOOLS SHOP & GARAGE	6.90%	19,008
RE 3951 GENERAL - LABORATORY EQUIP	1.86%	17,537
RE 3952 GENERAL - LABORATORY EQUIP	5.34%	14,373
RE 3953 GENERAL - LABORATORY EQUIP	5.01%	32,615
RE 397 GENERAL - COMMUNICATION EQUIP	5.09%	214,983
RE 398 GENERAL - MISCELLANEOUS EQUIP	3.75%	127,262
TOTAL GENERAL PLANT		**4,755,654**
TOTAL DEPRECIABLE ELECTRIC PLANT		**226,869,366**

ELECTRIC FUNCTIONS	**PRESENT RATES**	**ACTUAL PROVISIONS October 2016 to September 2017**
COMMON GENERAL		
EG 6901 COMMON GEN - STRUCTURES	2.20%	2,563,813
EG 69011 STRUCT & IMP- OSC 12TH ST	2.20%	545,292
EG 6902 COMMON GEN - STRUCTURES	2.08%	487,882
EG 6908 COMMON GEN - STRUCTURES-OFFICE LEASE	2.02%	30,729
EG 69081 COMMON GEN - STRUCTS-OFF LEASE-NCHAS METRO PLEX	2.02%	229,047
EG 69082 COMMON GEN - STRUCTS-OFF LEASE-NCHAS FLEX	2.02%	38,304
EG 6909 COMMON GEN - STRUCTURES-WAREHOUSE LEASE	1.91%	5,604
EG 6911 COMMON GEN - OFFICE FURN & EQUIP	6.01%	511,257
EG 6912 COMMON GEN - EDP EQUIPMENT	20.00%	361,756
EG 6913 COMMON GEN - DATA HANDLING EQUIP	3.78%	43,185
EG 69121 COMMON GEN - EDP EQUIP	0.00%	-
EG 6914 COMMON GEN - EDP (SCPSC ORDER) EQUIP	0.00%	-
EG 693 COMMON GEN - STORES EQUIPMENT	3.72%	364
EG 6941 COMMON GEN - TOOLS SHOP & GARAGE	4.81%	276
EG 6943 COMMON GEN - TOOLS SHOP & GARAGE	5.38%	15,486
EG 6944 COMMON GEN - TOOLS SHOP & GARAGE	5.22%	95,590
EG 6952 COMMON GEN - LABORATORY EQUIP	1.69%	1,104
EG 6953 COMMON GEN - LABORATORY EQUIP	4.65%	3,927
EG 697 COMMON GEN - COMMUNICATION EQUIP	16.39%	1,249,671
EG 697.8 COMMON GEN - COMMUNICATION EQUIP LH	21.89%	125,423
EG 698 COMMON GEN - MISCELLANEOUS EQUIP	6.87%	446,134
COMMON PLT ALLOCATED TO ELECT. COMMON GENERAL		6,754,844
TOTAL		**233,624,210**

SCE&G
A SCANA COMPANY

2014 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC AND COMMON PLANT
AS OF DECEMBER 31, 2014

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

SOUTH CAROLINA ELECTRIC & GAS COMPANY

Columbia, South Carolina

2014 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC AND COMMON PLANT
AS OF DECEMBER 31, 2014

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Camp Hill, Pennsylvania

Gannett Fleming

Excellence Delivered ***As Promised***

June 17, 2015

South Carolina Electric & Gas Company
100 SCANA Parkway
Cayce, SC 29033-3712

Attention Mr. James E. Swan
Controller

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric and common plant of South Carolina Electric & Gas Company as of December 31, 2014. The attached report presents a description of the methods used in the estimation of depreciation and the summary of annual and accrued depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John J. Spanos

JOHN J. SPANOS
Sr. Vice President

JJS:krm

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SOUTH CAROLINA ELECTRIC & GAS COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to South Carolina Electric & Gas Company's ("SCE&G" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the electric plant as of December 31, 2014. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life, and forecasted net salvage characteristics for each depreciable group of assets.

SCE&G's accounting policy has not changed since the last depreciation study was prepared. However, there have been changes in past and future retirement plans of assets, particularly at generating facilities. These changes have caused the proposed remaining lives in the depreciation study to become longer than those proposed in the previous depreciation study as of December 31, 2008.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric plant in service as of December 31, 2014 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $217.8 million when applied to depreciable plant balances as of December 31, 2014. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF DECEMBER 31, 2014	PROPOSED RATE	PROPOSED EXPENSE
Steam Production Plant	$1,818,215,576.49	**3.69**	$67,014,074
Nuclear Production Plant	1,057,805,596.76	**1.60**	16,949,252
Hydraulic Production Plant	609,710,372.62	**0.71**	4,326,683
Other Production Plant	787,369,882.41	**3.17**	24,951,618
Transmission Plant	1,025,358,232.46	**2.53**	25,892,924
Distribution Plant	2,879,420,633.44	**2.35**	67,574,351
General Plant	181,183,026.42	**2.56**	4,630,604
Common Plant	175,453,421.79	**3.71**	6,506,680
Total	**$8,534,516,742.39**	**2.55**	**$217,846,186**

PART I. INTRODUCTION

SOUTH CAROLINA ELECTRIC & GAS COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for South Carolina Electric & Gas Company ("Company"), as applied to specific electric plant in service as of December 31, 2014. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to current electric plant in service.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2014, the net salvage analyses of historical plant retirement data recorded through 2014; a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For all accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. Amortization accounting or vintage pooling is proposed for most general plant accounts.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts. For steam, nuclear, hydraulic and other production plants, the life span technique was used. In this technique, the date of final retirement was estimated for each unit, and the estimated survivor curves applied to each vintage were truncated at ages coinciding with the date of final retirement.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The estimates of net salvage by account incorporated a review of experienced costs of removal and salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and salvage, was stated in dollars and as a percent of retirement.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves,

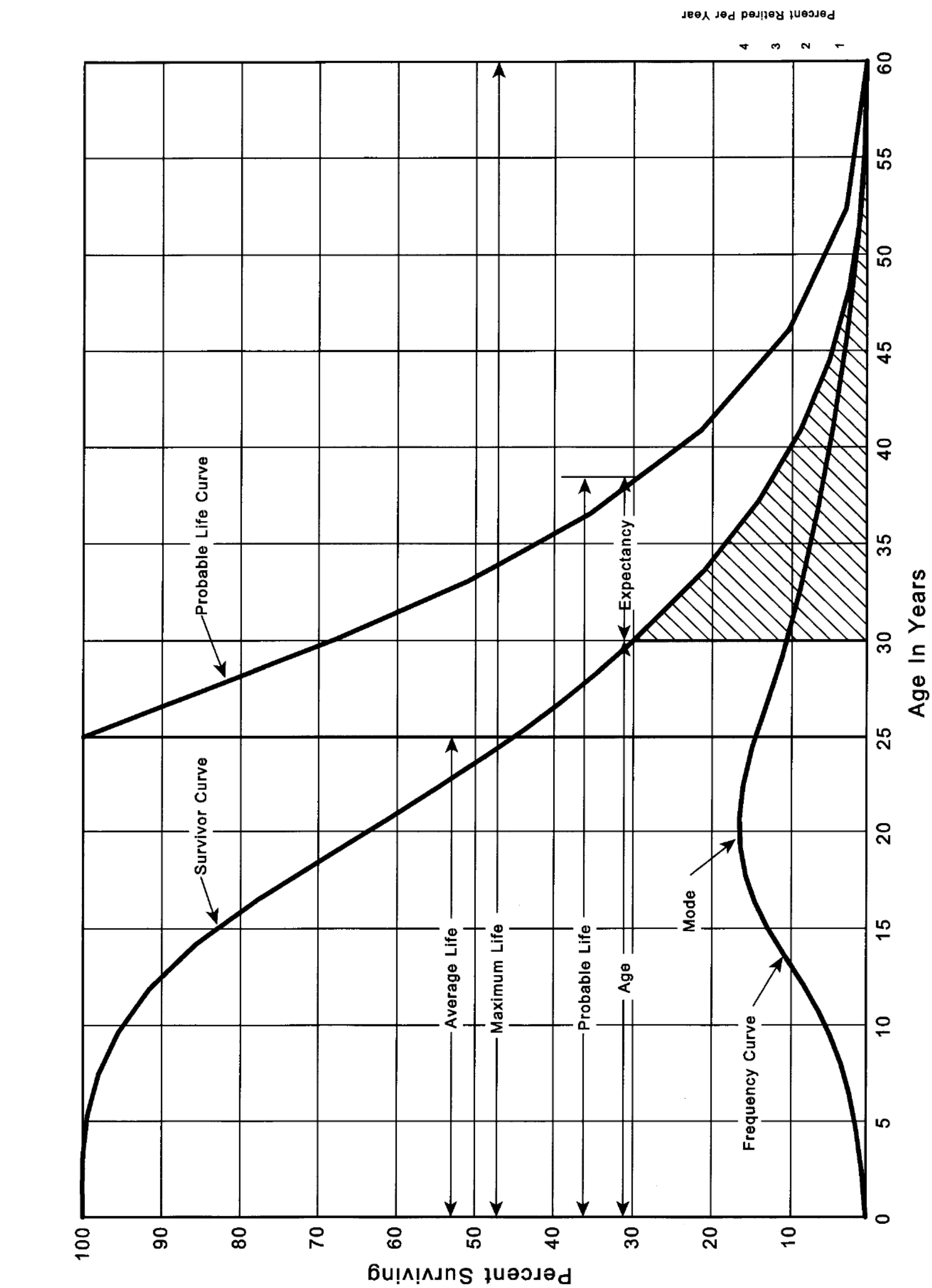


Figure 1. A Typical Survivor Curve and Derived Curves

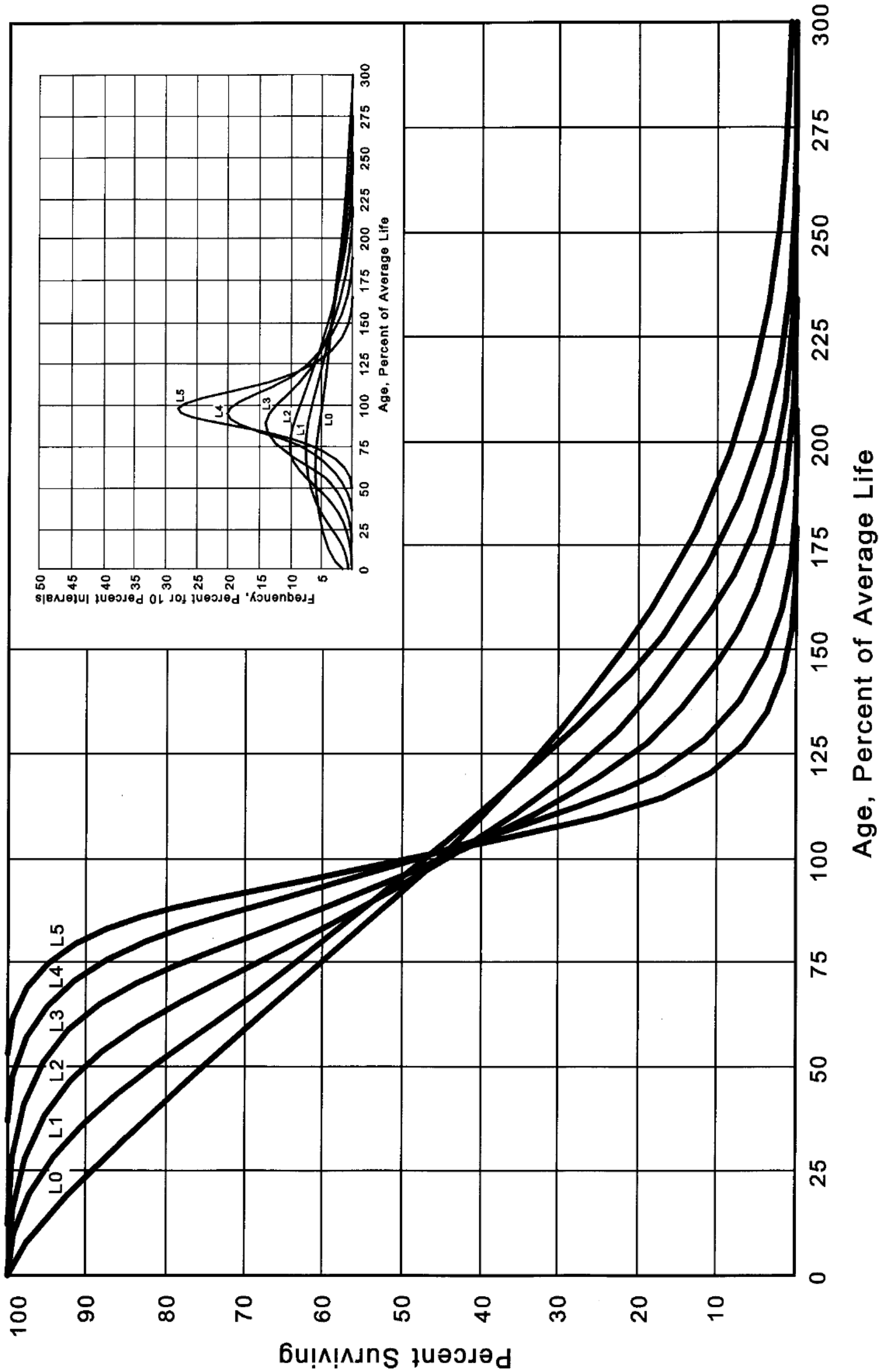


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

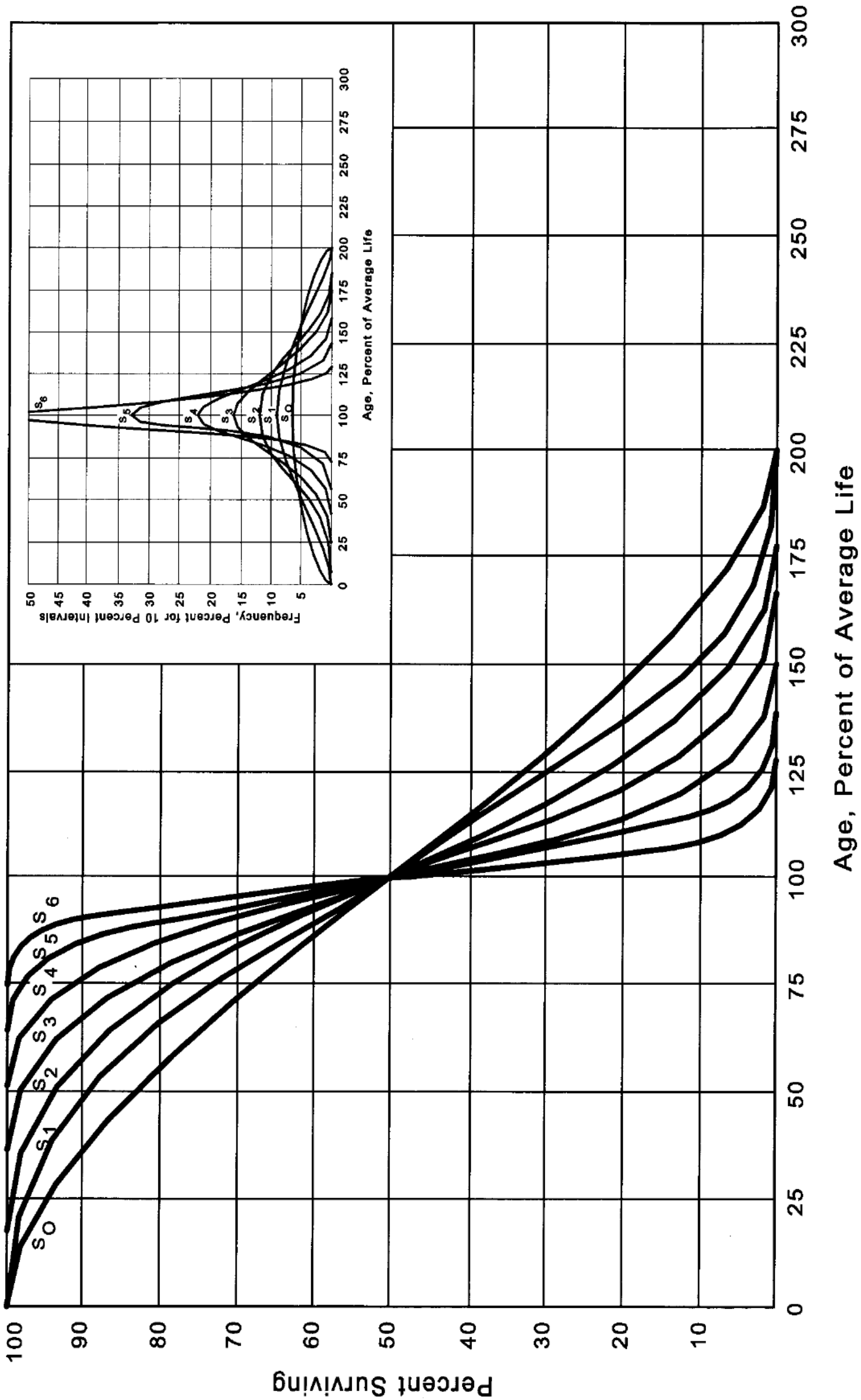


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

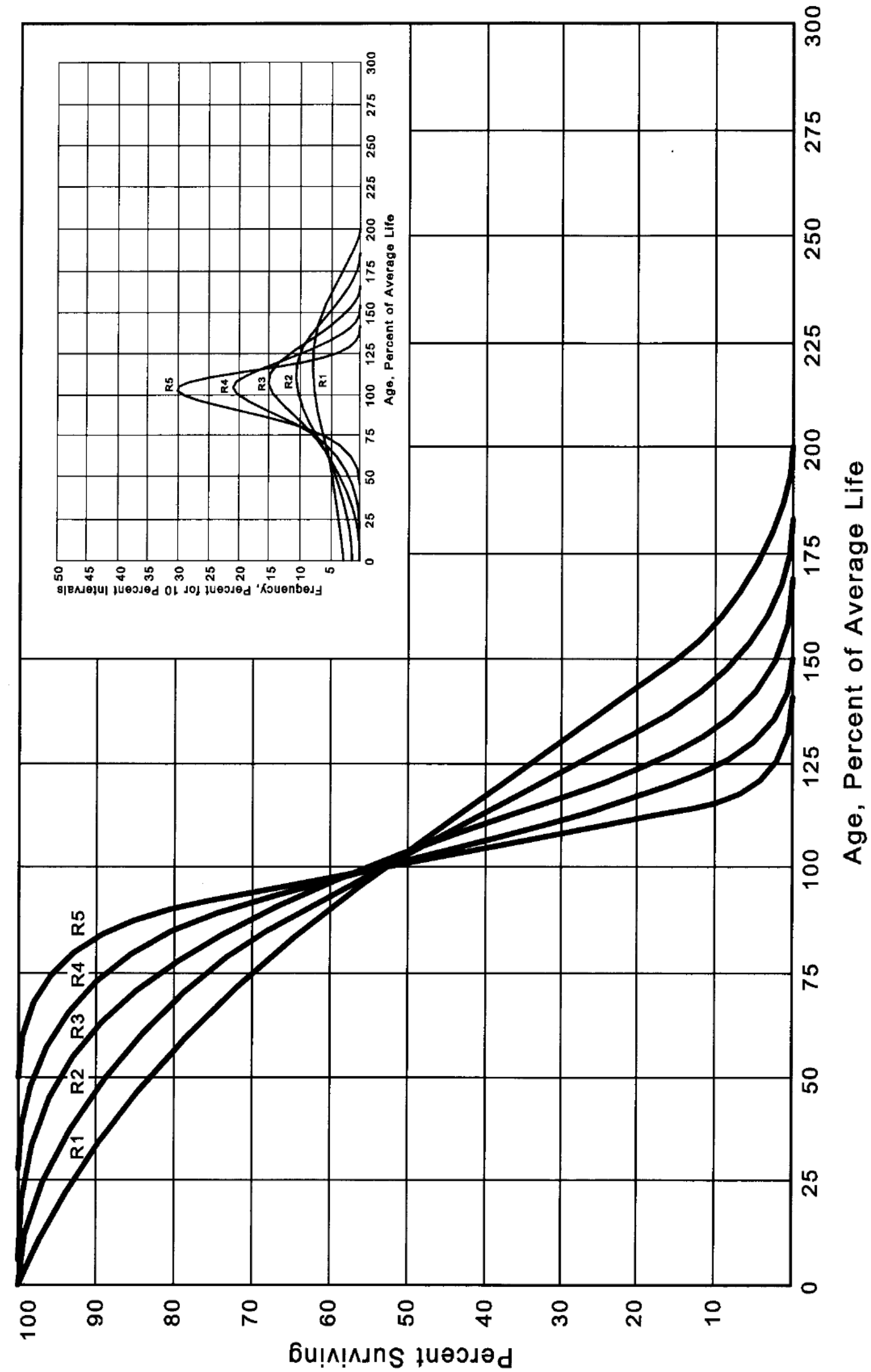


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

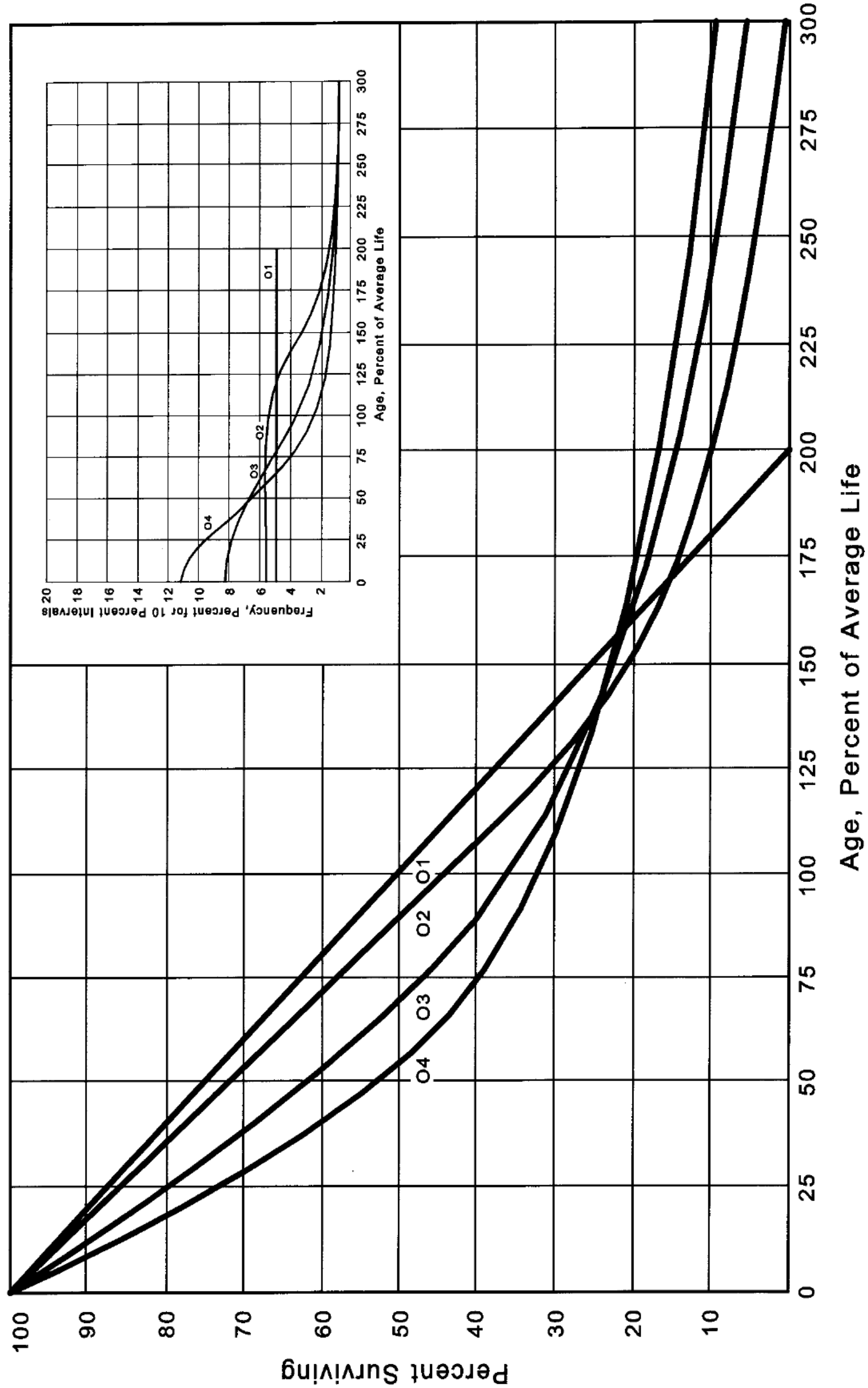


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125. These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College Engineering Experiment Station, Bulletin 125. 1935..
[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.
[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2005-2014 during which there were placements during the years 2000-2014. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2000 were retired in 2005. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2005 retirements of 2000 installations and ending with the 2014 retirements of the 2009 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014 | Placement Band 2000-2014

Year Placed	Retirements, Thousands of Dollars During Year 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Total During Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2001	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2002	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2003	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2004	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2005	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2006		5	11	12	13	14	15	16	18	20	113	7½-8½
2007			6	12	13	15	16	17	19	19	124	6½-7½
2008				6	13	15	16	17	19	19	131	5½-6½
2009					7	14	16	17	19	20	143	4½-5½
2010						8	18	20	22	23	146	3½-4½
2011							9	20	22	25	150	2½-3½
2012								11	23	25	151	1½-2½
2013									11	24	153	½-1½
2014										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014 | Placement Band 2000-2014

Year Placed (1)	2005 (2)	2006 (3)	2007 (4)	2008 (5)	2009 (6)	2010 (7)	2011 (8)	2012 (9)	2013 (10)	2014 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers and Sales, Thousands of Dollars — During Year											
2000	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2001	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2002	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2003	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2004	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2005	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2006		-	-	-	-	-	-	-	-	-	6	7½-8½
2007			-	-	-	-	-	-	-	-	-	6½-7½
2008				-	-	-	-	(12)[b]	-	-	-	5½-6½
2009					-	-	-	-	22[a]	-	-	4½-5½
2010						-	-	(19)[b]	-	-	10	3½-4½
2011							-	-	-	-	-	2½-3½
2012								-	-	(102)[c]	(121)	1½-2½
2013									-	-	-	½-1½
2014											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2005 through 2014 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or additions are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2010 are calculated in the following manner:

Exposures at age 0	= amount of addition	= \$750,000
Exposures at age ½	= \$750,000 - \$ 8,000	= \$742,000
Exposures at age 1½	= \$742,000 - \$18,000	= \$724,000
Exposures at age 2½	= \$724,000 - \$20,000 - \$19,000	= \$685,000
Exposures at age 3½	= \$685,000 - \$22,000	= \$663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014 | Placement Band 2000-2014

Year	Exposures, Thousands of Dollars										Total at	
	Annual Survivors at the Beginning of the Year										Beginning of	Age
Placed	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2001	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2002	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2003	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2004	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2005	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2006		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2007			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2008				580[a]	574	561	546	530	501	482	3,057	5½-6½
2009					660[a]	653	639	623	628	609	3,789	4½-5½
2010						750[a]	742	724	685	663	4,332	3½-4½
2011							850[a]	841	821	799	4,955	2½-3½
2012								960[a]	949	926	5,719	1½-2½
2013									1,080[a]	1,069	6,579	½-1½
2014										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

For the entire experience band 2005-2014, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2005-2014 | Placement Band 2000-2014

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

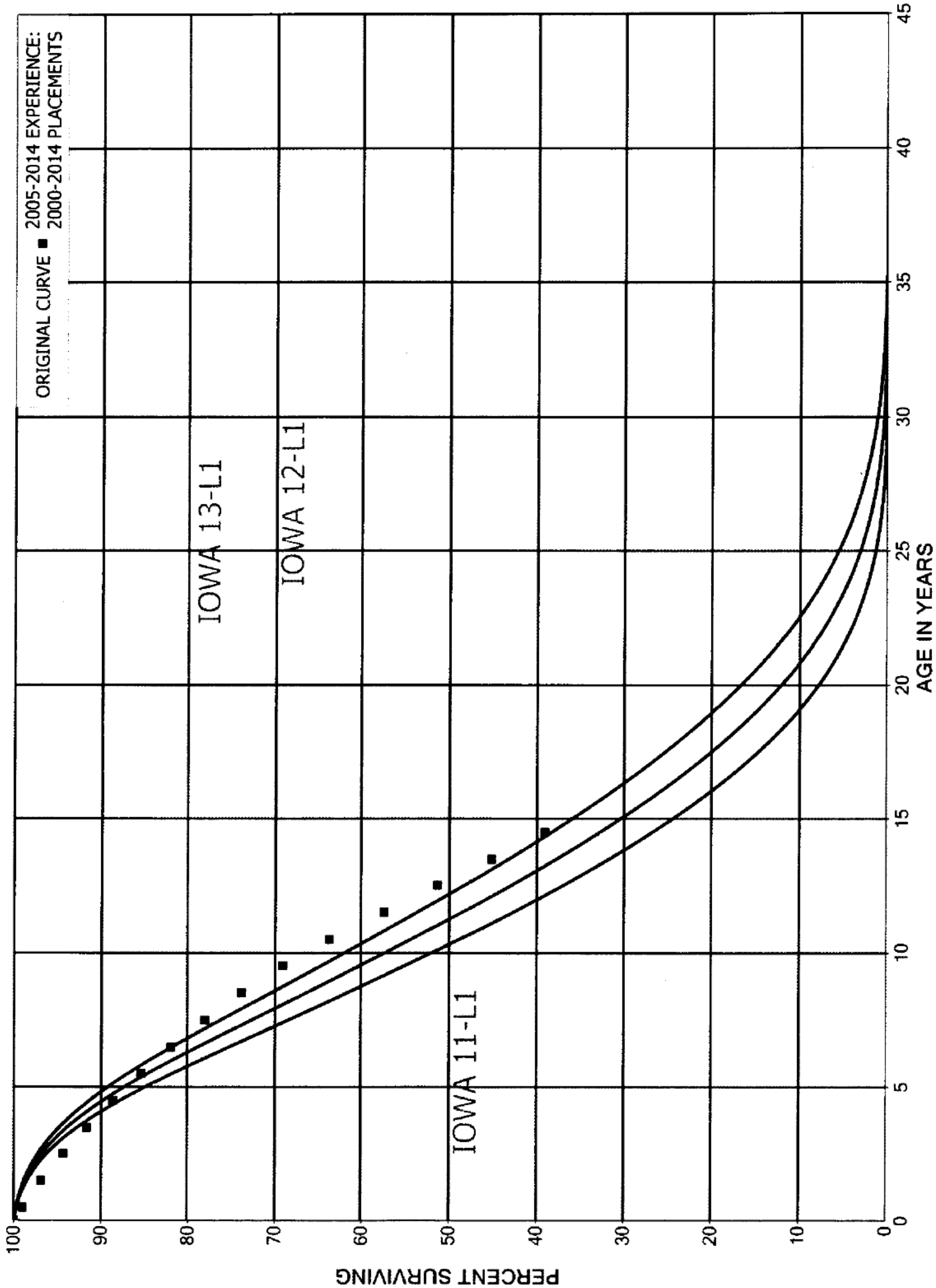


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

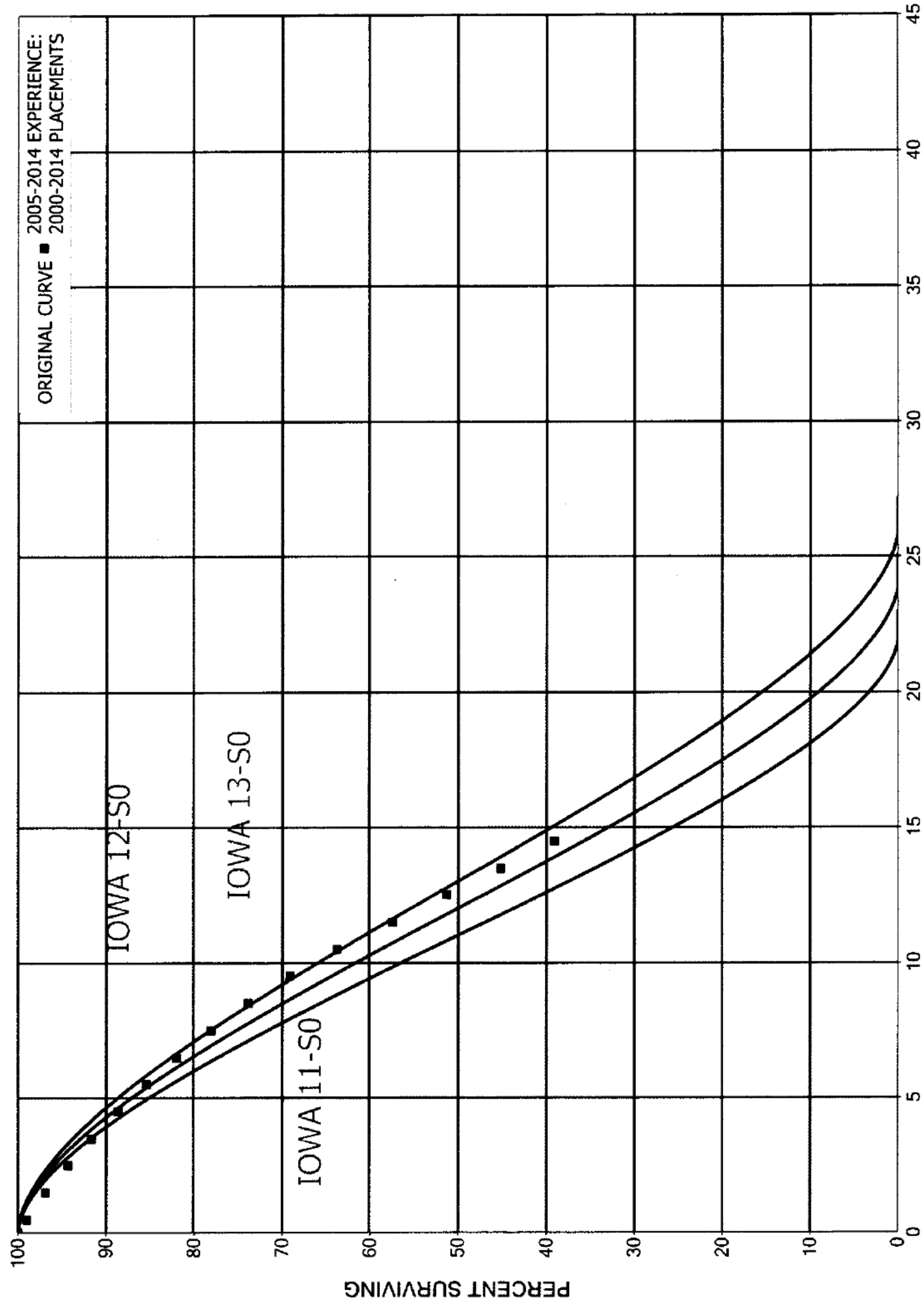


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

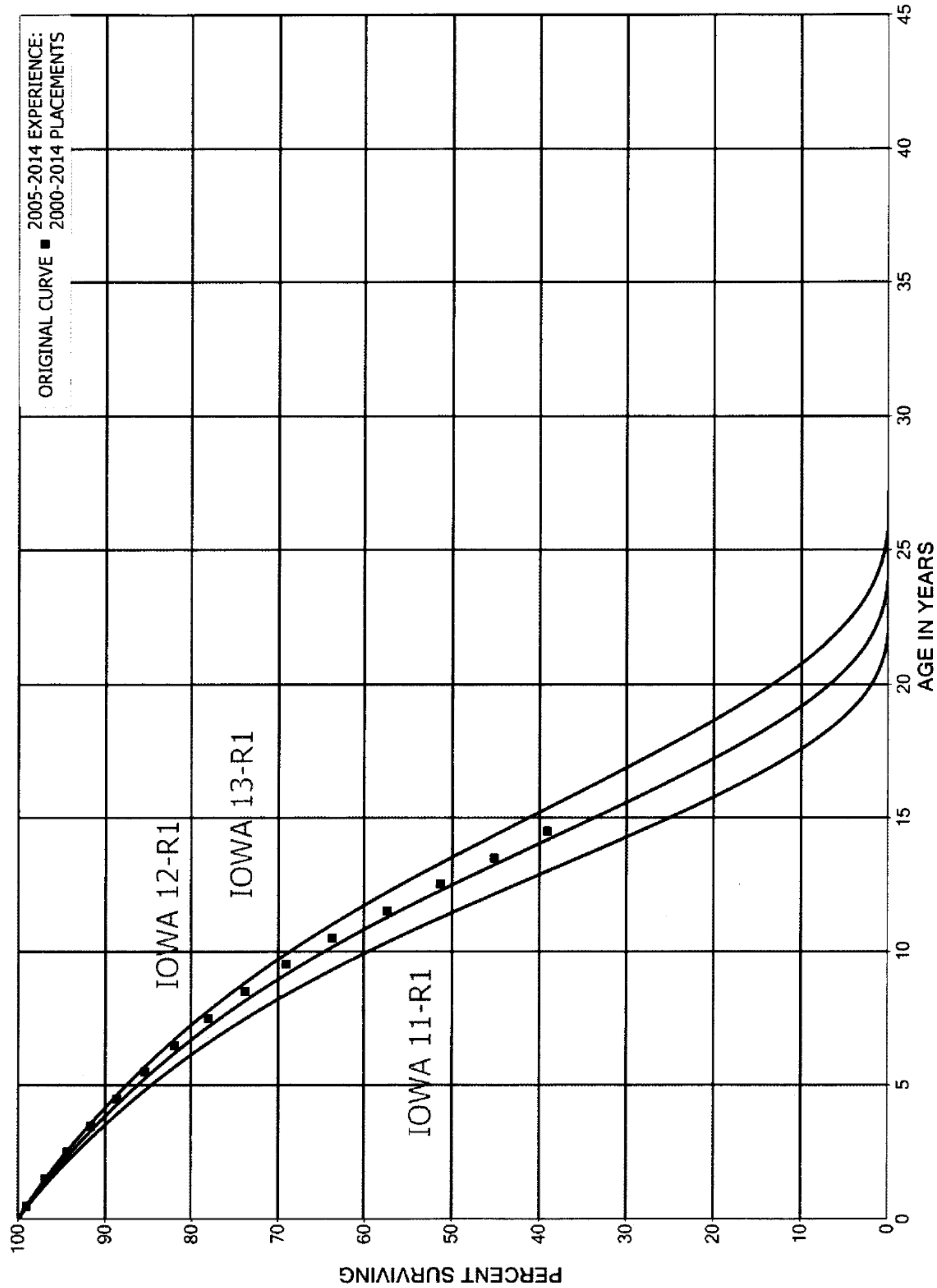
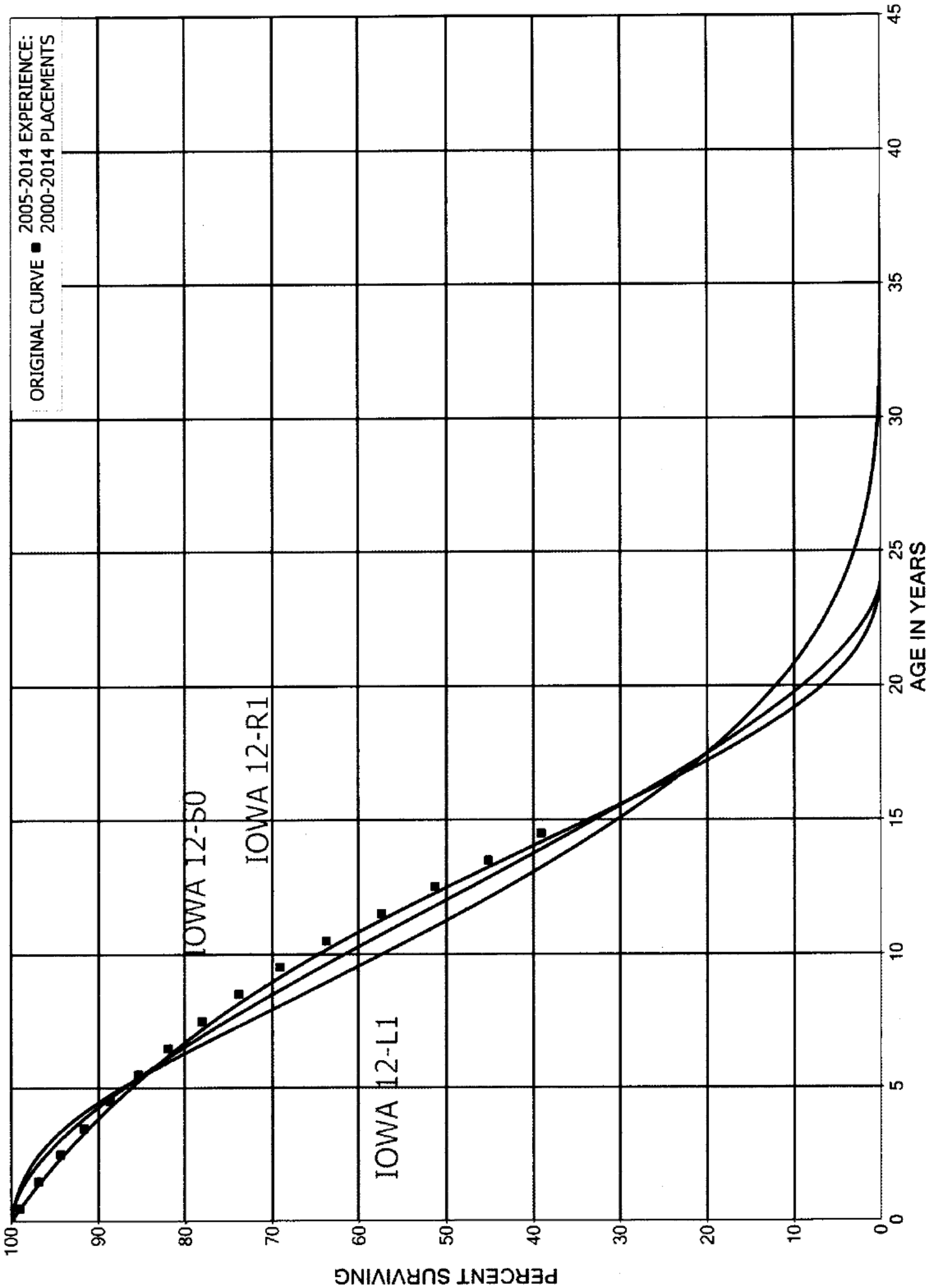


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and to observe representative portions of the plant, field trips were conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements was obtained during this trip. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The plant facilities visited on the most recent field trips in 2004, 2009 and 2015 are as follows:

<u>May 12-14, 2015</u>

- Edenwood Substation
- Congaree Creek Substation
- Coit Substation
- Columbia Office Complex
- McMeekin Generating Station
- Saluda Hydro Plant
- Central Lab
- Fairfield Pump Storage Facility
- Parr Hydro Station
- Coit Gas Turbine Station
- Wateree Generating Station

<u>July 14-16, 2009</u>

- Jasper Generating Station
- Cope Generating Station
- Wateree Generating Station
- Uptown Substation
- Edenwood Substation
- Congaree Creek Substation

March 30-31, 2004

Cope Generating Station
Williams Generating Station
Hagood CT Turbine Station
Coit Gas Turbine Station
Wateree Generating Station
McMeekin Generating Station
Central Lab
Saluda Hydro Plant

SERVICE LIFE ANALYSIS

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data, current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric utility companies.

For 28 plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. Generally, the information external to the statistics led to minimal or no significant departure from the indicated survivor curves for the accounts listed below.

STEAM PRODUCTION PLANT

311.00	Structures and Improvements
312.00	Boiler Plant Equipment
314.00	Turbogenerator Units
315.00	Accessory Electric Equipment
316.00	Miscellaneous Plant Equipment

NUCLEAR PRODUCTION PLANT

321.00	Structures and Improvements
322.00	Reactor Plant Equipment
325.00	Miscellaneous Power Plant Equipment

HYDRAULIC PRODUCTION PLANT

331.00	Structures and Improvements
335.00	Miscellaneous Power Plant Equipment

OTHER PRODUCTION PLANT

341.00	Structures and Improvements
342.00	Fuel Holders, Producers and Accessories
344.00	Generators
345.00	Accessory Electric Equipment

TRANSMISSION PLANT

352.00	Structures and Improvements
353.00	Station Equipment
353.10	Station Equipment - Step Up Transformer
355.00	Poles and Fixtures
356.10	Overhead Conductors and Devices - Overhead
356.20	Overhead Conductors and Devices - Fiber Optic

DISTRIBUTION PLANT

361.00	Structures and Improvements
362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
367.00	Underground Conductors and Devices
368.00	Line Transformers
370.00	Meters
373.00	Street Lighting and Signal Systems

Account 368.00, Line Transformers, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged plant accounting data for line transformers have been compiled for the years 1937 through 2014. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the periods 1937 through 2014 and 1989 through 2014. The Iowa 45-R2 is a reasonable fit of the original survivor curve. The 45-year service life is within the typical service life range of

30 to 50 years for line transformers. The 45-year life reflects the Company's plans to continue current practices of replacement for newer technology or high load needs.

Life Span Estimates

For Production Plant, which consists of large generating units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for steam, nuclear, hydraulic, and other production plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements through the period 2014.

The life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing and discussions with management personnel concerning the probable long-term outlook for the units.

The life span estimate for the steam units is 70 to 75 years. The majority of the steam facilities' life spans are more than 65 years which is the upper end of the typical range of life spans for such units. The longer life spans are based on the condition and utilization of the facilities. The 80-year lifespan for the nuclear facilities include the relicensing of the facility through 2062. The 150-year lifespan for the hydraulic production facilities is at the upper end of the typical range. The life span of each facility is determined by condition and Company plans. Life spans of 60 and 75 years were estimated for the combustion turbines. These life span estimates are longer than typical for combustion turbines which are used primarily as peaking units. The longer life spans are still considered appropriate as management has considered the condition and utilization of these units.

A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
McMeekin and Central Lab	1958	2028	70
Cope	1996	2071	75
Urquhart 3	1954	2028	74
Wateree	1970	2045	75
Jasper	2004	2079	75
Nuclear Production Plant			
V.C. Summer	1982	2062	80
Hydraulic Production Plant			
Fairfield	1978	2128	150
Neal Shoals	1905	2055	150
Parr	1914	2064	150
Saluda	1932	2082	150
Stevens Creek	1929	2079	150
Other Production Plant			
Coit	1969	2029	60
Hagood Unit 4	1991	2051	60
Hardeeville	1968	2018	50
Parr	1970	2030	60
Urquhart 1 and 2	1969	2044	75
Urquhart 3	1969	2029	60
Urquhart 4	1999	2059	60
Urquhart 5 and 6	2002	2077	75
Williams - Bushy Park	1997	2057	60
Jasper	2004	2079	75
Hagood Unit 5	2010	2070	60
Hagood Unit 6	2010	2070	60
Boeing Building Solar Project	2011	2031	20

The survivor curve estimates for the remaining accounts were based on judgment incorporating the statistical analyses and previous studies for this and other electric utilities.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled through 2014. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

Statistical analyses of historical data for the period 1987 through 2014 for electric plant were analyzed. The analyses contributed significantly toward the net salvage estimates for 34 plant accounts and subaccount of the depreciable plant, as follows:

Steam Production Plant

312.00	Boiler Plant Equipment
314.00	Turbogenerator Units
315.00	Accessory Electric Equipment
316.00	Miscellaneous Power Plant Equipment

Nuclear Production Plant

322.00	Reactor Plant Equipment
324.00	Accessory Electric Equipment
325.00	Miscellaneous Power Plant Equipment

Hydraulic Production Plant

333.00	Water Wheels, Turbines and Generators
335.00	Miscellaneous Power Plant Equipment

Other Production Plant

341.00	Structures and Improvements
343.00	Prime Movers
345.00	Accessory Electric Equipment
346.00	Miscellaneous Power Plant Equipment

Transmission Plant

353.00	Station Equipment
353.10	Station Equipment - Step-Up Transformers

Distribution Plant

361.00	Structures and Improvements
362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
366.00	Underground Conduit
367.00	Underground Conductors and Devices
368.00	Line Transformers
369.00	Services - Overhead
369.10	Services - Underground
370.00	Meters
373.00	Street Lighting and Signal Systems

General Plant

390.10	Structures and Improvements
390.20	Structures and Improvements - Warehouse
390.80	Structures and Improvements - Office Lease
380.80	Structures and Improvements - Warehouse Lease

Common Plant

690.10	Structures and Improvements - Office
690.20	Structures and Improvements - Warehouse
690.80	Structures and Improvements - Office Lease
690.90	Structures and Improvements - Warehouse Lease

Account 362.00, Station Equipment, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 1987 through 2014 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is

expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 1987-1989 through 2012-2014 periods were computed to smooth the annual amounts.

Cost of removal has fluctuated throughout the twenty-eight year period. The primary cause of the fluctuations in cost of removal relates to the type of station equipment removed each year. The large projects or inside the building assets have lower cost to remove per asset. Cost of removal for the most recent five years averaged 13 percent.

Gross salvage has also varied throughout the period, but has diminished to negligible levels since 1997. The most recent five-year average of 6 percent gross salvage reflects recent lower salvage value of station equipment.

The net salvage percent based on the overall period 1987 through 2014 is 11 percent negative net salvage and based on the most recent five-year period is 7 percent. The range of estimates made by other electric companies for Station Equipment is negative 5 to negative 25 percent. The net salvage estimate for station equipment is negative 10 percent, is within the range of other estimates and reflects the recent levels of negative net salvage.

The net salvage percents for the remaining accounts of plant were based on judgment incorporating estimates of previous studies of this and other electric utilities.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1,000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1,000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2014, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2014, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General and Common Plant accounts that represent numerous units of property, but a very small portion of total depreciable electric plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period, Years
391.10	Office Furniture and Equipment - Furniture	20
391.20	Office Furniture and Equipment - EDP	5
391.30	Office Furniture and Equipment - Data Handling	20
393	Stores Equipment	25
394	Tools, Shop, Garage Equipment	20
395	Laboratory Equipment	20
397	Communication Equipment	8
398	Miscellaneous Equipment	20
691.10	Office Furniture and Equipment - Furniture	20
691.20	Office Furniture and Equipment - EDP	5
691.30	Office Furniture and Equipment - Data Handling	20
693	Stores Equipment	25
694	Tools, Shop, Garage Equipment	20
695	Laboratory Equipment	20
697	Communication Equipment	8
698	Miscellaneous Equipment	20

For the purpose of calculating annual amortization amounts as of December 31, 2014, the book reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric plant in service as of December 31, 2014. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2014, is reasonable for a period of three to five years.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric and common plant as of December 31, 2014, is presented on pages VI-3 through VI-9 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2014

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	STEAM PRODUCTION PLANT								
	CENTRAL LAB								
311.00	STRUCTURES AND IMPROVEMENTS	85-R2	* (25)	3,392,489.97	2,327,747	1,912,865	144,352	4.26	13.3
315.00	ACCESSORY ELECTRIC EQUIPMENT	60-R2.5	* (15)	58,757.43	48,762	18,809	1,466	2.50	12.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	42-R0.5	* (5)	2,269,768.18	666,484	1,716,773	138,132	6.09	12.4
	TOTAL CENTRAL LAB			5,721,015.58	3,042,993	3,648,447	283,950	4.96	12.8
	COPE								
311.00	STRUCTURES AND IMPROVEMENTS	85-R2	* (25)	81,908,505.69	35,639,341	66,746,291	1,319,534	1.61	50.6
312.00	BOILER PLANT EQUIPMENT	40-S0	* (30)	330,467,286.34	146,694,478	282,912,994	9,736,294	2.95	29.1
314.00	TURBOGENERATOR UNITS	50-S0.5	* (25)	86,893,020.97	48,649,495	59,966,781	1,746,949	2.01	34.3
315.00	ACCESSORY ELECTRIC EQUIPMENT	60-R2.5	* (15)	23,826,635.24	12,708,860	14,691,771	351,730	1.48	41.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	42-R0.5	* (5)	10,380,219.87	3,657,776	7,241,455	215,492	2.08	33.6
	TOTAL COPE			533,475,668.11	247,349,950	431,559,292	13,369,999	2.51	32.3
	MCMEEKIN								
311.00	STRUCTURES AND IMPROVEMENTS	85-R2	* (25)	20,833,996.44	12,142,195	13,900,301	1,051,169	5.05	13.2
312.00	BOILER PLANT EQUIPMENT	40-S0	* (30)	132,385,472.08	63,949,664	108,151,450	8,904,674	6.73	12.1
314.00	TURBOGENERATOR UNITS	50-S0.5	* (25)	38,285,564.98	19,299,422	28,557,534	2,258,568	5.90	12.6
315.00	ACCESSORY ELECTRIC EQUIPMENT	60-R2.5	* (15)	11,149,507.77	6,023,863	6,798,071	509,989	4.57	13.3
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	42-R0.5	* (5)	4,886,505.43	2,409,794	2,721,037	222,388	4.55	12.2
	TOTAL MCMEEKIN			207,541,046.70	103,824,938	160,128,393	12,946,788	6.24	12.4
	URQUHART 3								
311.00	STRUCTURES AND IMPROVEMENTS	85-R2	* (25)	16,765,025.73	12,101,790	8,854,492	676,981	4.04	13.1
312.00	BOILER PLANT EQUIPMENT	40-S0	* (30)	21,297,684.31	4,802,110	22,884,880	2,043,165	9.59	11.2
314.00	TURBOGENERATOR UNITS	50-S0.5	* (25)	44,000,273.95	26,443,093	28,557,249	2,275,365	5.17	12.6
315.00	ACCESSORY ELECTRIC EQUIPMENT	60-R2.5	* (15)	9,479,951.82	5,675,670	5,226,275	406,279	4.29	12.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	42-R0.5	* (5)	4,677,436.37	1,022,067	3,889,241	312,484	6.68	12.4
	TOTAL URQUHART 3			96,220,372.18	50,044,730	69,412,137	5,714,274	5.94	12.1
	WATEREE								
311.00	STRUCTURES AND IMPROVEMENTS	85-R2	* (25)	124,882,195.68	34,605,527	121,497,218	4,140,681	3.32	29.3
312.00	BOILER PLANT EQUIPMENT	40-S0	* (30)	567,456,867.68	196,134,920	541,559,008	22,503,323	3.97	24.1
314.00	TURBOGENERATOR UNITS	50-S0.5	* (25)	142,966,596.60	65,400,440	113,307,806	4,375,561	3.06	25.9
315.00	ACCESSORY ELECTRIC EQUIPMENT	60-R2.5	* (15)	27,602,068.39	10,796,619	20,945,760	750,435	2.72	27.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	42-R0.5	* (5)	5,801,669.94	2,321,384	3,770,369	155,139	2.67	24.3
	TOTAL WATEREE			868,709,398.29	309,258,890	801,080,161	31,925,139	3.68	25.1
	JASPER								
312.00	BOILER PLANT EQUIPMENT	40-S0	* (30)	471,370.95	65,801	546,981	16,094	3.41	34.0
314.00	TURBOGENERATOR UNITS	50-S0.5	* (25)	101,661,051.43	19,867,222	107,209,092	2,677,743	2.63	40.0
315.00	ACCESSORY ELECTRIC EQUIPMENT	60-R2.5	* (15)	4,120,842.11	1,198,970	3,539,998	72,898	1.77	48.6
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	42-R0.5	* (5)	294,811.14	31,464	278,088	7,189	2.44	38.7
	TOTAL JASPER			106,548,075.63	21,163,457	111,574,159	2,773,924	2.60	40.2
	TOTAL STEAM PRODUCTION PLANT			**1,818,215,576.49**	**734,684,958**	**1,577,402,589**	**67,014,074**	**3.69**	**23.5**
	NUCLEAR PRODUCTION PLANT								
321.00	STRUCTURES AND IMPROVEMENTS	85-R2	* (3)	279,880,275.02	161,892,748	126,383,935	2,996,787	1.07	42.2
322.00	REACTOR PLANT EQUIPMENT	60-R2.5	* (4)	472,683,438.30	261,030,866	230,559,910	6,414,593	1.36	35.9
323.00	TURBOGENERATOR UNITS	50-S0.5	* (5)	97,859,052.79	34,779,495	67,972,510	2,152,834	2.20	31.6
324.00	ACCESSORY ELECTRIC EQUIPMENT	55-R3	* (2)	101,500,574.21	68,122,326	35,408,260	1,200,417	1.18	29.5
325.00	MISCELLANEOUS POWER PLANT EQUIPMENT	31-R2	* (4)	105,882,256.44	30,396,281	79,721,266	4,184,621	3.95	19.1
	TOTAL NUCLEAR PRODUCTION PLANT			**1,057,805,596.76**	**556,221,716**	**540,045,881**	**16,949,252**	**1.60**	**31.9**

SOUTH CAROLINA ELECTRIC & GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2014

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	HYDRAULIC PRODUCTION PLANT								
	FAIRFIELD								
331.00	STRUCTURES AND IMPROVEMENTS	105-R2 *	(10)	36,207,392.21	16,961,647	22,866,484	312,562	0.86	73.2
332.00	RESERVOIRS, DAMS AND WATERWAYS	125-R2.5 *	(15)	74,465,834.65	33,899,540	51,736,170	602,380	0.81	85.9
333.00	WATER WHEELS, TURBINES AND GENERATORS	85-R1.5 *	(15)	67,430,660.72	18,991,510	58,553,750	917,229	1.36	63.8
334.00	ACCESSORY ELECTRIC EQUIPMENT	60-R0.5 *	(15)	14,607,604.33	1,067,787	15,730,958	301,292	2.06	52.2
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	65-R1.5 *	(10)	6,190,215.68	1,804,791	5,004,446	104,928	1.70	47.7
336.00	ROADS, RAILROADS AND BRIDGES	70-R4 *	0	1,328,336.30	756,586	571,750	16,545	1.25	34.6
	TOTAL FAIRFIELD			200,230,043.89	73,481,861	154,463,558	2,254,936	1.13	68.5
	NEAL SHOALS								
331.00	STRUCTURES AND IMPROVEMENTS	105-R2 *	(10)	739,576.95	487,835	325,700	8,440	1.14	38.6
332.00	RESERVOIRS, DAMS AND WATERWAYS	125-R2.5 *	(15)	3,617,212.05	869,828	3,289,966	85,216	2.36	38.6
333.00	WATER WHEELS, TURBINES AND GENERATORS	85-R1.5 *	(15)	2,832,863.65	1,654,848	1,602,945	43,192	1.52	37.1
334.00	ACCESSORY ELECTRIC EQUIPMENT	60-R0.5 *	(15)	379,187.68	214,933	221,133	6,556	1.73	33.7
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	65-R1.5 *	(10)	259,951.29	157,890	128,056	3,615	1.39	35.4
336.00	ROADS, RAILROADS AND BRIDGES	70-R4 *	0	2,645.06	2,035	610	17	0.64	35.9
	TOTAL NEAL SHOALS			7,831,436.68	3,387,369	5,568,410	147,036	1.88	37.9
	PARR								
331.00	STRUCTURES AND IMPROVEMENTS	105-R2 *	(10)	1,881,466.85	224,944	1,844,670	40,062	2.13	46.0
332.00	RESERVOIRS, DAMS AND WATERWAYS	125-R2.5 *	(15)	4,272,776.17	2,106,878	2,806,815	58,872	1.38	47.7
333.00	WATER WHEELS, TURBINES AND GENERATORS	85-R1.5 *	(15)	2,843,514.82	751,062	2,518,980	55,489	1.95	45.4
334.00	ACCESSORY ELECTRIC EQUIPMENT	60-R0.5 *	(15)	1,859,314.56	772,134	1,366,078	34,973	1.88	39.1
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	65-R1.5 *	(10)	432,273.73	137,578	337,923	7,913	1.83	42.7
336.00	ROADS, RAILROADS AND BRIDGES	70-R4 *	0	124,197.66	78,758	45,440	970	0.78	46.8
	TOTAL PARR			11,413,543.79	4,071,354	8,919,906	198,279	1.74	45.0
	SALUDA								
331.00	STRUCTURES AND IMPROVEMENTS	105-R2 *	(10)	7,665,417.97	2,561,392	5,870,568	99,049	1.29	59.3
332.00	RESERVOIRS, DAMS AND WATERWAYS	125-R2.5 *	(15)	21,775,503.55	14,250,885	10,790,944	189,210	0.87	57.0
332.50	RESERVOIRS, DAMS AND WATERWAYS - SALUDA BACKUP DAM	125-R2.5 *	0	332,845,902.01	260,773,549	72,072,353	1,119,130	0.34	64.4
333.00	WATER WHEELS, TURBINES & GENERATORS	85-R1.5 *	(15)	9,876,812.45	5,037,164	6,321,170	125,990	1.28	50.2
334.00	ACCESSORY ELECTRIC EQUIPMENT	60-R0.5 *	(15)	1,556,355.57	727,177	1,062,632	24,620	1.58	43.2
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	65-R1.5 *	(10)	1,754,120.74	406,118	1,523,415	30,179	1.72	50.5
336.00	ROADS, RAILROADS AND BRIDGES	70-R4 *	0	233,526.53	142,034	91,493	2,077	0.89	44.1
	TOTAL SALUDA			375,707,638.82	283,898,319	97,732,575	1,590,255	0.42	61.5
	STEVENS CREEK								
331.00	STRUCTURES AND IMPROVEMENTS	105-R2 *	(10)	2,880,962.34	1,673,643	1,495,416	25,566	0.89	58.5
332.00	RESERVOIRS, DAMS AND WATERWAYS	125-R2.5 *	(15)	6,432,284.11	3,960,185	3,436,942	55,653	0.87	61.8
333.00	WATER WHEELS, TURBINES AND GENERATORS	85-R1.5 *	(15)	2,461,809.02	1,497,425	1,333,655	24,097	0.98	55.3
334.00	ACCESSORY ELECTRIC EQUIPMENT	60-R0.5 *	(15)	1,621,021.13	1,050,775	813,399	18,290	1.13	44.5
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	65-R1.5 *	(10)	1,002,820.96	554,276	548,827	11,236	1.12	48.8
336.00	ROADS, RAILROADS AND BRIDGES	70-R4 *	0	128,811.88	53,715	75,097	1,335	1.04	56.3
	TOTAL STEVENS CREEK			14,527,709.44	8,790,019	7,703,336	136,177	0.94	56.6
	TOTAL HYDRAULIC PRODUCTION PLANT			**609,710,372.62**	**373,628,922**	**274,387,786**	**4,326,683**	**0.71**	**63.4**

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2014

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	OTHER PRODUCTION PLANT								
	COIT								
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5 *	(5)	181,870.46	144,976	45,988	3,275	1.80	14.0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1 *	(15)	551,814.73	503,128	131,459	9,611	1.74	13.7
343.00	PRIME MOVERS	28-R2.5 *	(10)	1,126,109.32	896,623	342,097	26,605	2.36	12.9
344.00	GENERATORS	60-S1.5 *	(10)	3,500,249.62	3,571,703	278,572	22,229	0.64	12.5
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	(10)	629,642.25	379,131	313,475	22,064	3.50	14.2
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1 *	0	161,533.47	123,717	37,816	2,823	1.75	13.4
	TOTAL COIT			6,151,219.85	5,619,278	1,149,407	86,607	1.41	13.3
	HAGOOD UNIT 4								
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5 *	(5)	3,534,937.42	2,581,813	1,129,871	44,681	1.26	25.3
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1 *	(15)	807,728.67	765,838	163,050	6,976	0.86	23.4
343.00	PRIME MOVERS	28-R2.5 *	(10)	24,297,364.96	20,774,303	5,952,798	544,775	2.24	10.9
344.00	GENERATORS	60-S1.5 *	(10)	6,035,469.54	4,733,969	1,905,047	64,892	1.08	29.4
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	(10)	2,441,219.68	1,849,968	835,374	38,105	1.56	21.9
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1 *	0	344,472.48	72,308	272,164	9,784	2.84	27.8
	TOTAL HAGOOD			37,461,192.75	30,778,199	10,258,304	709,213	1.89	14.5
	HARDEEVILLE								
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5 *	(5)	57,556.13	34,257	26,177	7,544	13.11	3.5
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1 *	(15)	534,349.66	451,151	163,351	47,062	8.81	3.5
343.00	PRIME MOVERS	28-R2.5 *	(10)	798,792.01	653,614	225,057	66,210	8.29	3.4
344.00	GENERATORS	60-S1.5 *	(10)	1,862,867.44	1,046,430	1,002,724	290,963	15.62	3.4
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	(10)	282,978.33	120,854	190,422	56,648	20.02	3.4
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1 *	0	74,224.68	3,251	70,974	20,600	27.75	3.4
	TOTAL HARDEEVILLE			3,610,768.25	2,309,557	1,678,705	489,027	13.54	3.4
	PARR								
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5 *	(5)	877,417.43	495,167	426,121	28,894	3.29	14.7
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1 *	(15)	581,073.80	478,734	189,501	15,184	2.61	12.5
343.00	PRIME MOVERS	28-R2.5 *	(10)	3,671,856.95	460,593	3,578,450	263,034	7.16	13.6
344.00	GENERATORS	60-S1.5 *	(10)	3,095,840.82	2,937,237	468,188	33,969	1.10	13.8
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	(10)	1,096,224.92	609,996	595,851	39,989	3.65	14.9
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1 *	0	196,134.32	94,652	101,482	7,275	3.71	13.9
	TOTAL PARR			9,518,548.24	5,076,379	5,359,593	388,345	4.08	13.8
	URQUHART 1 AND 2								
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5 *	(5)	1,089,988.44	243,140	901,348	33,370	3.06	27.0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1 *	(15)	197,131.97	97,227	129,475	5,392	2.74	24.0
343.00	PRIME MOVERS	28-R2.5 *	(10)	632,912.96	176,496	519,708	24,006	3.79	21.6
344.00	GENERATORS	60-S1.5 *	(10)	3,412,182.40	2,055,892	1,697,509	75,144	2.20	22.6
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	(10)	123,571.03	21,995	113,933	5,260	4.26	21.7
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1 *	0	88,339.80	15,871	72,469	2,998	3.39	24.2
	TOTAL URQUHART 1 AND 2			5,544,126.60	2,610,621	3,434,442	146,170	2.64	23.5
	URQUHART 3								
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5 *	(5)	353,753.36	45,668	325,773	22,925	6.48	14.2
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1 *	(15)	7,717.92	4,802	4,074	295	3.82	13.8
343.00	PRIME MOVERS	28-R2.5 *	(10)	215,177.89	11,568	225,128	16,231	7.54	13.9
344.00	GENERATORS	60-S1.5 *	(10)	1,633,202.75	1,191,690	604,833	46,202	2.83	13.1
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	(10)	56,301.48	13,082	48,850	3,429	6.09	14.2
	TOTAL URQUHART 3			2,266,153.40	1,266,810	1,208,658	89,082	3.93	13.6

SOUTH CAROLINA ELECTRIC & GAS COMPANY
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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	URQUHART 4									
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5	*	(5)	316,053.48	250,475	81,381	2,629	0.83	31.0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1	*	(15)	959,234.17	928,282	174,837	5,801	0.60	30.1
343.00	PRIME MOVERS	28-R2.5	*	(10)	2,445,351.48	299,656	2,390,231	92,299	3.77	25.9
344.00	GENERATORS	60-S1.5	*	(10)	19,799,005.32	11,966,088	9,812,818	269,436	1.36	36.4
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(10)	1,367,730.57	563,650	940,854	30,550	2.23	30.8
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1	*	0	44,352.73	11,765	32,588	1,037	2.34	31.4
	TOTAL URQUHART 4				24,931,727.75	14,019,916	13,432,709	401,752	1.61	33.4
	URQUHART 5 AND 6									
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5	*	(5)	4,617,639.91	2,022,205	2,826,317	83,176	1.80	34.0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1	*	(15)	3,609,181.00	2,035,424	2,115,134	63,434	1.76	33.3
343.00	PRIME MOVERS	28-R2.5	*	(10)	230,541,447.77	110,749,261	142,846,332	8,088,307	3.51	17.7
344.00	GENERATORS	60-S1.5	*	(10)	13,383,303.82	3,964,488	10,757,146	240,156	1.79	44.8
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(10)	15,752,063.28	7,463,108	9,864,162	350,817	2.23	28.1
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1	*	0	136,549.34	20,745	115,804	3,373	2.47	34.3
	TOTAL URQUHART 5 AND 6				268,040,185.12	126,255,231	168,524,895	8,829,263	3.29	19.1
	WILLIAMS - BUSHY PARK									
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5	*	(5)	596,412.59	196,573	429,660	12,415	2.08	34.6
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1	*	(15)	159,083.07	134,456	48,490	1,489	0.94	32.6
343.00	PRIME MOVERS	28-R2.5	*	(10)	6,345,280.32	4,980,294	1,999,514	119,868	1.89	16.7
344.00	GENERATORS	60-S1.5	*	(10)	76,680.22	61,758	22,590	593	0.77	38.1
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(10)	295,361.37	124,367	200,531	6,439	2.18	31.1
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1	*	0	116,619.70	62,748	53,872	1,825	1.56	29.5
	TOTAL WILLIAMS - BUSHY PARK				7,589,437.27	5,560,196	2,754,657	142,629	1.88	19.3
	JASPER									
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5	*	(5)	28,138,016.99	7,845,789	21,699,129	606,519	2.16	35.8
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1	*	(15)	5,976.38	926	5,947	159	2.66	37.4
343.00	PRIME MOVERS	28-R2.5	*	(10)	306,773,117.22	132,147,012	205,303,417	10,861,803	3.54	18.9
344.00	GENERATORS	60-S1.5	*	(10)	32,741,316.98	9,363,994	26,651,455	571,062	1.74	46.7
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(10)	26,238,837.39	9,599,698	19,263,023	648,344	2.47	29.7
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1	*	0	486,538.61	19,030	467,509	14,122	2.90	33.1
	TOTAL JASPER				394,383,803.57	158,976,449	273,390,480	12,702,009	3.22	21.5
	HAGOOD UNIT 5									
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5	*	(5)	350,421.52	42,459	325,484	8,144	2.32	40.0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1	*	(15)	336,637.51	45,042	342,091	8,853	2.63	38.6
343.00	PRIME MOVERS	28-R2.5	*	(10)	4,993,200.27	3,009,276	2,483,244	103,572	2.07	24.0
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(10)	2,476,617.34	222,326	2,501,953	70,831	2.86	35.3
	TOTAL HAGOOD UNIT 5				8,156,876.64	3,319,103	5,652,772	191,400	2.35	29.5
	HAGOOD UNIT 6									
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5	*	(5)	687,165.48	83,106	638,418	15,975	2.32	40.0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45-S1	*	(15)	418,638.95	56,001	425,434	11,010	2.63	38.6
343.00	PRIME MOVERS	28-R2.5	*	(10)	5,517,288.85	3,288,338	2,780,680	116,873	2.12	23.8
344.00	GENERATORS	60-S1.5	*	(10)	3,644.91	259	3,750	77	2.11	48.7
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(10)	3,704,883.57	459,315	3,616,057	102,412	2.76	35.3
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1	*	0	21,579.33	2,602	18,977	556	2.58	34.1
	TOTAL HAGOOD UNIT 6				10,353,201.09	3,889,621	7,483,316	246,903	2.38	30.3

SOUTH CAROLINA ELECTRIC & GAS COMPANY
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	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	BOEING BUILDING SOLAR PROJECT								
341.00	STRUCTURES AND IMPROVEMENTS	45-R2.5 *	(5)	117,179.22	18,911	104,127	6,369	5.44	16.3
344.00	GENERATORS	60-S1.5 *	(10)	7,030,745.12	1,134,665	6,599,155	397,061	5.65	16.6
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	(10)	2,197,108.36	354,254	2,062,565	124,853	5.68	16.5
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	38-R1 *	0	17,609.18	3,170	14,439	935	5.31	15.4
	TOTAL BOEING BUILDING SOLAR PROJECT			9,362,641.88	1,511,000	8,780,286	529,218	5.65	16.6
	TOTAL OTHER PRODUCTION PLANT			**787,369,882.41**	**361,192,360**	**503,108,224**	**24,951,618**	**3.17**	**20.2**
	TRANSMISSION PLANT								
352.00	STRUCTURES AND IMPROVEMENTS								
	V.C. SUMMER - NUCLEAR	65-R2 *	(10)	605,051.07	443,447	222,109	9,205	1.52	24.1
	OTHER LOCATIONS	65-R2 *	(10)	4,084,321.86	768,549	3,724,205	72,710	1.78	51.2
	TOTAL STRUCTURES AND IMPROVEMENTS			4,689,372.93	1,211,996	3,946,314	81,915	1.75	48.2
353.00	STATION EQUIPMENT								
	V.C. SUMMER - NUCLEAR	60-S0.5 *	(15)	17,777,461.43	5,428,916	15,015,165	582,697	3.28	25.8
	PARR - HYDRO	60-S0.5 *	(15)	375,936.02	237,986	194,340	8,614	2.29	22.6
	FAIRFIELD PUMPED STORAGE	60-S0.5 *	(15)	1,149,510.89	1,112,111	209,827	4,650	0.40	45.1
	SALUDA - HYDRO	60-S0.5 *	(15)	8,096,558.63	3,811,476	5,499,566	186,599	2.30	29.5
	STEVENS CREEK - HYDRO	60-S0.5 *	(15)	4,640,244.71	1,379,821	3,956,460	212,478	4.58	18.6
	NEAL SHOALS - HYDRO	60-S0.5 *	(15)	26,922.21	30,103	858	60	0.22	14.3
	OTHER LOCATIONS	60-S0.5	(15)	328,407,061.01	92,804,351	284,863,769	5,940,964	1.81	47.9
	TOTAL STATION EQUIPMENT			360,473,694.90	104,804,764	309,739,985	6,936,062	1.92	44.7
353.10	STATION EQUIPMENT - STEP UP TRANSFORMERS								
	V.C SUMMER - NUCLEAR	55-S2.5 *	(15)	13,746,024.82	2,695,221	13,112,708	498,228	3.62	26.3
	PARR - HYDRO	55-S2.5 *	(15)	397,439.96	284,358	172,698	10,057	2.53	17.2
	FAIRFIELD PUMPED STORAGE	55-S2.5 *	(15)	7,698,519.87	2,262,556	6,590,742	142,566	1.85	46.2
	SALUDA - HYDRO	55-S2.5 *	(15)	595,189.21	478,842	205,626	8,964	1.51	22.9
	WATEREE - STEAM	55-S2.5 *	(15)	5,570,895.24	686,870	5,719,660	234,456	4.21	24.4
	MCMEEKIN - STEAM	55-S2.5 *	(15)	818,997.20	680,000	261,847	19,314	2.36	13.6
	URQUHART - STEAM	55-S2.5 *	(15)	1,365,809.34	1,326,382	244,299	25,630	1.88	9.5
	WILLIAMS - STEAM	55-S2.5 *	(15)	10,159,516.28	6,043,603	5,639,841	224,507	2.21	25.1
	COPE - STEAM	55-S2.5 *	(15)	6,020,025.00	2,459,745	4,463,284	131,080	2.18	34.1
	WILLIAMS GT	55-S2.5 *	(15)	150,417.37	146,366	26,614	2,957	1.97	9.0
	HARDEEVILLE GT	55-S2.5 *	(15)	118,166.04	106,019	29,872	1,888	1.60	15.8
	COIT GT	55-S2.5 *	(15)	118,154.04	134,068	1,809	1,231	1.04	1.5
	URQUHART GT	55-S2.5 *	(15)	124,338.10	139,628	3,361	3,361	2.70	1.0
	HAGOOD GT	55-S2.5 *	(15)	1,821,482.80	1,422,687	672,018	23,932	1.31	28.1
	STEVENS CREEK - HYDRO	55-S2.5 *	(15)	403,651.76	238,584	225,616	7,744	1.92	29.1
	JASPER	55-S2.5 *	(15)	19,100,579.87	4,868,803	17,096,864	422,041	2.21	40.5
	TOTAL STATION EQUIPMENT - STEP UP TRANSFORMERS			68,209,206.90	23,973,732	54,466,859	1,757,956	2.58	31.0
353.80	STATION EQUIPMENT - LEASEHOLD	20-SQ	0	1,463,910.93	664,064	799,847	86,422	5.90	9.3
354.00	TOWERS AND FIXTURES	75-R3	(40)	5,414,270.73	4,624,837	2,955,142	73,927	1.37	40.0
355.00	POLES AND FIXTURES	53-L2	(70)	318,840,518.48	101,112,541	440,916,340	10,609,318	3.33	41.6
355.80	POLES AND FIXTURES - LEASEHOLD	20-SQ	0	2,080,514.77	86,622	1,993,893	119,384	5.74	16.7
356.10	OVERHEAD CONDUCTORS AND DEVICES - OVERHEAD	60-R2.5	(45)	183,879,485.09	65,648,986	200,976,267	4,603,145	2.50	43.7
356.20	OVERHEAD CONDUCTORS AND DEVICES - FIBER OPTIC	60-R2.5	(45)	2,893,641.21	924,940	3,270,840	71,480	2.47	45.8
356.80	OVERHEAD CONDUCTORS AND DEVICES - LEASEHOLD	20-SQ	0	1,089,444.31	579,595	509,849	126,024	11.57	4.0

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2014

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
357.00	UNDERGROUND CONDUIT	60-R3	0	20,724,923.15	3,145,528	17,579,395	336,329	1.62	52.3
358.00	UNDERGROUND CONDUCTORS AND DEVICES	50-R3	0	55,524,863.57	6,851,463	48,673,401	1,089,915	1.96	44.7
359.00	ROADS AND TRAILS	65-R4	0	74,385.49	16,153	58,232	1,047	1.41	55.6
	TOTAL TRANSMISSION PLANT			**1,025,358,232.46**	**313,645,221**	**1,085,886,364**	**25,892,924**	**2.53**	**41.9**
	DISTRIBUTION PLANT								
361.00	STRUCTURES AND IMPROVEMENTS	65-R2	(10)	4,844,174.21	1,002,881	4,325,711	82,348	1.70	52.5
361.80	STRUCTURES AND IMPROVEMENTS - LEASEHOLD	20-SQ	0	66,541.62	32,703	33,839	7,520	11.30	4.5
362.00	STATION EQUIPMENT	60-S0.5	(10)	362,131,240.08	66,405,796	331,938,568	7,002,973	1.93	47.4
362.80	STATION EQUIPMENT - LEASEHOLD	20-SQ	0	3,443,523.40	892,804	2,550,719	190,221	5.52	13.4
364.00	POLES, TOWERS AND FIXTURES	43-R1.5	(30)	419,374,576.09	117,822,665	427,364,284	13,066,667	3.12	32.7
365.00	OVERHEAD CONDUCTORS AND DEVICES	57-R1.5	(10)	458,625,116.31	145,126,825	359,360,803	7,718,743	1.68	46.6
366.00	UNDERGROUND CONDUIT	60-R2.5	(5)	139,579,890.14	46,542,089	100,016,796	2,042,565	1.46	49.0
367.00	UNDERGROUND CONDUCTORS AND DEVICES	49-S0.5	(5)	408,277,969.67	118,322,923	310,368,945	7,856,917	1.92	39.5
368.00	LINE TRANSFORMERS	45-R2	(5)	442,674,067.00	163,306,908	301,500,862	9,045,312	2.04	33.3
369.00	SERVICES - OVERHEAD	65-R3	(70)	101,327,748.03	58,792,502	113,464,670	2,448,691	2.42	46.3
369.10	SERVICES - UNDERGROUND	65-S2.5	(10)	165,172,299.55	53,565,377	128,124,153	2,485,729	1.50	51.5
370.00	METERS	22-L1	0	19,658,085.09	10,710,048	8,948,037	514,896	2.62	17.4
370.30	METERS - AMR	15-L3	0	63,631,642.81	6,154,258	57,477,385	6,101,785	9.59	9.4
370.40	METERS - AMI	15-S2.5	0	10,790,992.68	323,581	10,467,412	932,703	8.64	11.2
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	37-S0.5	(15)	279,822,766.76	93,014,543	228,781,639	8,077,281	2.89	28.3
	TOTAL DISTRIBUTION PLANT			**2,879,420,633.44**	**882,015,903**	**2,384,723,823**	**67,574,351**	**2.35**	**35.3**
	GENERAL PLANT								
390.10	STRUCTURES AND IMPROVEMENTS	50-S0	(10)	136,249,244.16	34,442,390	115,431,779	2,595,732	1.91	44.5
390.20	STRUCTURES AND IMPROVEMENTS - WAREHOUSE	50-R2.5	(10)	9,933,186.62	1,270,281	9,656,224	225,125	2.27	42.9
390.80	STRUCTURES AND IMPROVEMENTS - OFFICE LEASE	50-S0	(10)	145,185.39	132,764	26,940	763	0.53	35.3
390.90	STRUCTURES AND IMPROVEMENTS - WAREHOUSE LEASE	50-R2.5	(10)	111,031.25	35,100	87,034	3,093	2.79	28.1
391.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	7,986,681.64	2,335,791	5,650,891	419,032	5.25	13.5
391.20	OFFICE FURNITURE AND EQUIPMENT - EDP	5-SQ	0	1,320,954.77	841,622	479,333	264,177	20.00	1.8
391.30	OFFICE FURNITURE AND EQUIPMENT - DATA HANDLING	20-SQ	0	316,927.03	134,024	182,903	20,390	6.43	9.0
393.00	STORES EQUIPMENT	25-SQ	0	270,241.41	209,730	60,511	9,500	3.52	6.4
394.10	TOOLS, SHOP AND GARAGE EQUIPMENT - HAND TOOLS	20-SQ	0	471,457.15	217,535	253,922	25,126	5.33	10.1
394.20	TOOLS, SHOP AND GARAGE EQUIPMENT - LINE	20-SQ	0	2,452,491.27	1,356,584	1,095,907	76,067	3.10	14.4
394.30	TOOLS, SHOP AND GARAGE EQUIPMENT - SHOP	20-SQ	0	267,978.28	129,562	138,416	18,165	6.78	7.6
394.40	TOOLS, SHOP AND GARAGE EQUIPMENT - GARAGE	20-SQ	0	283,505.59	61,901	221,605	19,556	6.90	11.3
395.10	LABORATORY EQUIPMENT - METER TEST	20-SQ	0	1,649,769.81	1,205,070	444,700	30,644	1.86	14.5
395.20	LABORATORY EQUIPMENT - OTHER TEST	20-SQ	0	420,207.03	148,975	271,232	22,447	5.34	12.1
395.30	LABORATORY EQUIPMENT - FIELD TEST	20-SQ	0	4,006,391.96	1,843,209	2,163,183	200,742	5.01	10.8
397.00	COMMUNICATION EQUIPMENT	8-SQ	0	9,454,297.57	7,381,969	2,072,329	481,030	5.09	4.3
398.00	MISCELLANEOUS EQUIPMENT	20-SQ	0	5,843,475.49	2,949,566	2,893,909	219,015	3.75	13.2
	TOTAL GENERAL PLANT			**181,183,026.42**	**54,696,073**	**141,130,818**	**4,630,604**	**2.56**	**30.5**
	COMMON PLANT								
690.10	STRUCTURES AND IMPROVEMENTS - OFFICE	50-S0	(10)	105,911,527.94	18,535,509	97,967,172	2,332,188	2.20	42.0
690.20	STRUCTURES AND IMPROVEMENTS - WAREHOUSE	50-R2.5	(10)	23,473,558.33	4,326,167	21,494,747	487,788	2.08	44.1
690.80	STRUCTURES AND IMPROVEMENTS - OFFICE LEASE	50-S0	(10)	14,458,644.99	2,534,863	13,369,646	292,210	2.02	45.8
690.90	STRUCTURES AND IMPROVEMENTS - WAREHOUSE LEASE	50-R2.5	(10)	293,437.21	82,029	240,752	5,595	1.91	43.0
691.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	8,729,213.33	3,367,890	5,361,323	524,449	6.01	10.2
691.20	OFFICE FURNITURE AND EQUIPMENT - EDP	5-SQ	0	4,296,920.97	2,903,969	1,392,952	859,389	20.00	1.6
691.30	OFFICE FURNITURE AND EQUIPMENT - DATA HANDLING	20-SQ	0	1,264,549.73	1,023,678	240,871	47,766	3.78	5.0
693.00	STORES EQUIPMENT	25-SQ	0	181,054.10	172,091	8,963	6,743	3.72	1.3
694.10	TOOLS, SHOP AND GARAGE EQUIPMENT - POWER TOOLS	20-SQ	0	6,027.25	4,835	1,192	290	4.81	4.1
694.30	TOOLS, SHOP AND GARAGE EQUIPMENT - SHOP TOOLS	20-SQ	0	283,787.12	202,517	81,270	15,256	5.38	5.3

SOUTH CAROLINA ELECTRIC & GAS COMPANY
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	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
694.40	TOOLS, SHOP AND GARAGE EQUIPMENT - GARAGE	20-SQ	0	1,696,869.46	761,450	935,419	88,513	5.22	10.6
695.20	LABORATORY EQUIPMENT - OTHER TEST	20-SQ	0	100,045.98	90,735	9,311	1,693	1.69	5.5
695.30	LABORATORY EQUIPMENT - FIELD TEST	20-SQ	0	86,637.39	63,674	22,963	4,026	4.65	5.7
697.00	COMMUNICATION EQUIPMENT	8-SQ	0	7,858,044.90	4,430,224	3,427,821	1,287,682	16.39	2.7
697.80	COMMUNICATION EQUIPMENT - LEASEHOLD	8-SQ	0	565,776.48	129,998	435,778	123,854	21.89	3.5
698.00	MISCELLANEOUS EQUIPMENT	20-SQ	0	6,247,326.61	2,776,760	3,470,567	429,238	6.87	8.1
	TOTAL COMMON PLANT			**175,453,421.79**	**41,406,389**	**148,460,747**	**6,506,680**	**3.71**	**22.8**
	TOTAL DEPRECIABLE PLANT			**8,534,516,742.39**	**3,317,491,542**	**6,655,146,231**	**217,846,186**	**2.55**	**30.5**
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED								
301.00	ORGANIZATION			14,988.33	14,988				
302.00	FRANCHISES AND CONSENTS			4,643,673.29	2,927,935				
302.20	FRANCHISES AND CONSENTS - NUCLEAR			8,564,832.09	2,401,694				
303.00	MISCELLANEOUS INTANGIBLE PLANT			37,759,448.67	29,823,935				
303.20	MISCELLANEOUS INTANGIBLE PLANT - NUCLEAR			26,801,103.18	21,604,407				
303.50	CIPv5 MISCELLANEOUS INTANGIBLE PLANT			148,536.44	19,603				
310.00	LAND OWNED IN FEE			13,561,300.52					
320.10	LAND OWNED IN FEE			880,611.29					
330.10	LAND OWNED IN FEE			29,442,651.89					
340.10	LAND OWNED IN FEE			2,917,985.94					
350.10	LAND OWNED IN FEE			12,530,370.35					
350.20	LAND RIGHTS AND EASEMENTS			66,088,334.74					
350.80	LAND RIGHTS AND EASEMENTS - LEASE			90,300.04	2,709				
353.10	BURTON - STATION EQUIPMENT - STEP UP TRANSFORMERS			0.00	13,349				
360.10	LAND OWNED IN FEE			21,312,246.19					
360.20	LAND RIGHTS AND EASEMENTS			31,504,344.69					
389.10	LAND OWNED IN FEE			6,730,374.33					
392.00	TRANSPORTATION EQUIPMENT			18,498,249.66	12,779,637				
396.00	POWER OPERATED EQUIPMENT			41,147,673.40	27,768,101				
603.00	MISCELLANEOUS INTANGIBLE PLANT			124,733,868.03	114,953,649				
689.10	LAND OWNED IN FEE			21,257,547.18					
689.20	LAND RIGHTS			1,028.94					
692.00	TRANSPORTATION EQUIPMENT			7,093,738.41	4,924,644				
696.00	POWER OPERATED EQUIPMENT			2,404,713.58	1,483,387				
	TOTAL NONDEPRECIABLE PLANT			**478,127,921.18**	**218,718,038**				
	TOTAL ELECTRIC PLANT			**9,012,644,663.57**	**3,536,209,580**	**6,655,146,231**	**217,846,186**		

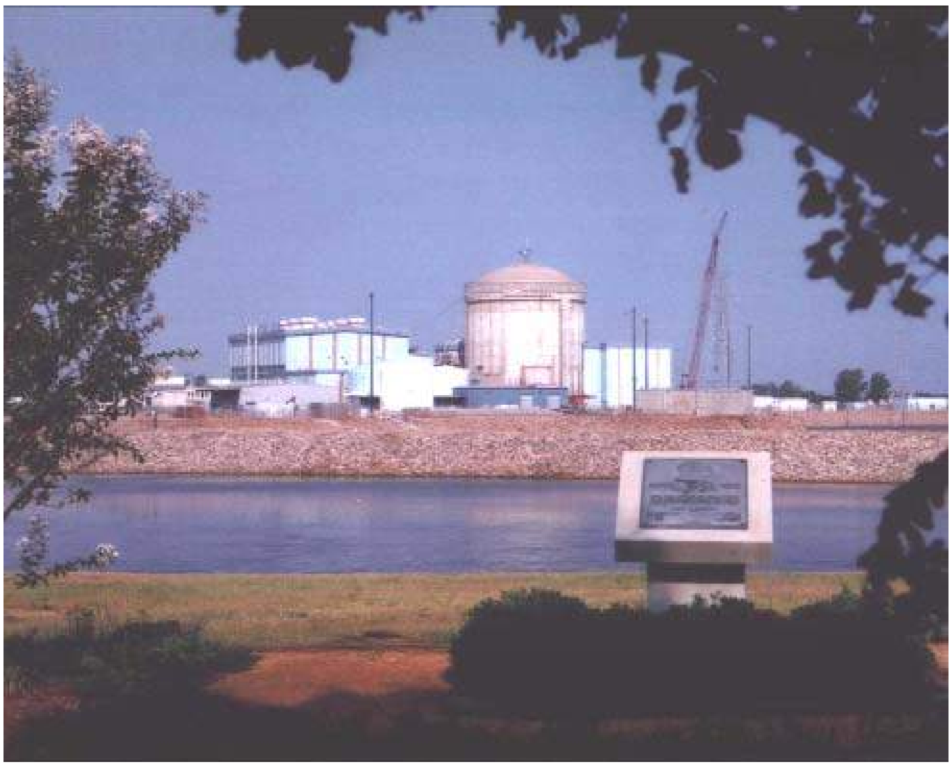
* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.

Document S06-1727-001, Rev. 0

DECOMMISSIONING COST ANALYSIS

for the

VIRGIL C. SUMMER NUCLEAR STATION



prepared for

South Carolina Electric & Gas Company

prepared by

TLG Services, Inc.
Bridgewater, Connecticut

June 2016

APPROVALS

Project Manager	William A. Cloutier, Jr.	06 Jun 2016 Date
Project Engineer	Thomas J. Garrett	6/6/16 Date
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REVISION LOG

No.	Date	Item Revised	Reason for Revision
0	06-06-2016		Original Issue

EXECUTIVE SUMMARY

This report presents estimates of the cost to decommission the Virgil C. Summer Nuclear Station (VCSNS) for the selected decommissioning scenarios following the scheduled cessation of plant operations. The estimates are designed to provide South Carolina Electric & Gas Company, (SCE&G) and South Carolina Public Service Authority (Santee Cooper), the plant's owners, with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear unit.

The analysis relies upon site-specific, technical information from an evaluation prepared in 2012,[1] updated to reflect current assumptions pertaining to the disposition of the nuclear plant and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but estimates prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission VCSNS; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, were reviewed for this analysis. The following structures were added to the 2012 inventory: FLEX storage building, emergency response building, and combined maintenance shop.

The costs to decommission VCSNS for the scenarios evaluated are tabulated at the end of this section. Costs are reported in 2016 dollars and include monies anticipated to be spent for radiological remediation and operating license termination, spent fuel management, and site restoration activities.

A complete discussion of the assumptions relied upon in this analysis is provided in Section 3, along with schedules of annual expenditures for each scenario. A sequence of significant project activities is provided in Section 4 with a timeline for each scenario. Detailed cost reports used to generate the summary tables contained within this document are provided in Appendices C through F.

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1 "Decommissioning Cost Analysis for the Virgil C. Summer Nuclear Station," Document S06-1662-001, Rev. 0, TLG Services, Inc., February 2013

Consistent with the 2012 analysis, the current cost estimates assume that the shutdown of the nuclear unit is a scheduled and pre-planned event (e.g., there is no delay in transitioning the plant and workforce from operations or in obtaining regulatory relief from operating requirements, etc.). The estimates include the continued operation of the fuel handling building as an interim wet fuel storage facility for approximately seven years after operations cease. During this time period, it is assumed that the spent fuel residing in the pool that cannot be directly transferred to the Department of Energy (DOE) will be moved to an independent spent fuel storage installation (ISFSI) for interim storage.

The ISFSI will remain operational until the DOE is able to complete the transfer of the fuel to a federal facility (e.g., a monitored retrievable storage facility).[2] DOE has breached its obligations to remove fuel from reactor sites, and has also failed to provide the plant owner with information about how it will ultimately perform. DOE officials have stated that DOE does not have an obligation to accept already-canistered fuel without an amendment to DOE's contracts with plant licensees to remove the fuel (the "Standard Contract"), but DOE has not explained what any such amendment would involve. Consequently, the plant owner has no information or expectations on how DOE will remove fuel from the site in the future. In the absence of information about how DOE will perform, and for purposes of this analysis only, it is assumed that DOE will accept already-canistered fuel. (It is recognized that the canisters may not be licensed or licensable for transportation when DOE performs.) If this assumption is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers.

Alternatives and Regulations

The Nuclear Regulatory Commission (NRC) provided general decommissioning requirements in a rule adopted on June 27, 1988. [3] In this rule, the NRC set forth technical and financial criteria for decommissioning licensed nuclear facilities. The regulations addressed planning needs, timing, funding methods, and environmental review requirements for decommissioning. The rule also defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB.

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2 Projected expenditures for spent fuel management identified in the cost analyses do not consider the outcome of the litigation with the DOE with regard to the delays incurred by the owners in the timely removal of spent fuel from the site.

3 U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72 "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, Federal Register Volume 53, Number 123 (p 24018 et seq.), June 27, 1988

DECON is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."[4]

SAFSTOR is defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use."[5] Decommissioning is required to be completed within 60 years, although longer time periods will be considered when necessary to protect public health and safety.

ENTOMB is defined as "the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactive material decays to a level permitting unrestricted release of the property."[6] As with the SAFSTOR alternative, decommissioning is currently required to be completed within 60 years, although longer time periods will also be considered when necessary to protect public health and safety.

The 60-year restriction has limited the practicality for the ENTOMB alternative at commercial reactors that generate significant amounts of long-lived radioactive material. In 1997, the Commission directed its staff to re-evaluate this alternative and identify the technical requirements and regulatory actions that would be necessary for entombment to become a viable option. The resulting evaluation provided several recommendations, however, rulemaking has been deferred pending the completion of additional research studies (e.g., on engineered barriers).

In 1996, the NRC published revisions to its general requirements for decommissioning nuclear power plants to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process.[7] The

4 Ibid. Page FR24022, Column 3

5 Ibid.

6 Ibid. Page FR24023, Column 2

7 U.S. Code of Federal Regulations, Title 10, Parts 2, 50, and 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, Federal Register Volume 61, (p 39278 et seq.), July 29, 1996

amendments allow for greater public participation and better define the transition process from operations to decommissioning. Regulatory Guide 1.184, issued in July 2000, further described the methods and procedures that are acceptable to the NRC staff for implementing the requirements of the 1996 revised rule that relate to the initial activities and the major phases of the decommissioning process. The costs and schedules presented in this analysis follow the general guidance and sequence in the amended regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202, issued February 2005. [8]

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[9] The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details are included in this analysis, including the ISFSI decommissioning estimate (Appendix F).

Decommissioning Scenarios

Three decommissioning scenarios were evaluated for the VCSNS nuclear unit. The scenarios selected are representative of alternatives available to the owners and are defined as follows:

1. The first scenario assumes that plant would be promptly decommissioned (DECON alternative) upon the expiration of the current operating license, i.e., in 2042. The spent fuel is relocated to the ISFSI for interim storage and to facilitate the decontamination and dismantling of the power block structures. The ISFSI will remain operational, after the plant is decommissioned, until the transfer of the spent fuel to the DOE is complete (approximately 53 years after the cessation of operations for the purpose of this estimate).

2. The second scenario assumes that the plant is placed into safe-storage (SAFSTOR alternative) upon the expiration of the current operating license, i.e., in 2042. The spent fuel is relocated to the ISFSI for interim storage and so that the plant

8 "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," Regulatory Guide 1.202, Nuclear Regulatory Commission, February 2005

9 U.S. Code of Federal Regulations, Title 10, Parts 20, 30, 40, 50, 70, and 72, "Decommissioning Planning," Nuclear Regulatory Commission, Federal Register Volume 76, (p 35512 et seq.), June 17, 2011

systems can be drained and de-energized. Decommissioning is deferred until the spent fuel is removed from the site (approximately 53 years after the cessation of operations, consistent with the DECON alternative). The license is terminated within the required 60-year period. This alternative is designated SAFSTOR-1.

3. The third scenario assumes that the plant operates an additional 20 years. It also assumes that the plant is placed into safe-storage (SAFSTOR alternative) at the conclusion of the extended operating period, i.e., in 2062. Spent fuel remaining in the storage pool that has not been transferred to the DOE (based upon the start date assumed in Scenarios 1 and 2), is relocated to the ISFSI. The ISFSI will remain operational until the transfer of the spent fuel to the DOE is complete (approximately 47 years after the cessation of operations). The plant will remain in storage for another 7 years after the fuel is removed from the site at which time decommissioning will commence. The license is terminated within the required 60-year period. This alternative is designated SAFSTOR-2.

Methodology

The methodology used to develop the estimates follows the basic approach originally presented in the cost estimating guidelines[10] developed by the Atomic Industrial Forum (now Nuclear Energy Institute). This reference describes a unit cost factor method for estimating decommissioning activity costs. The unit cost factors used in this analysis incorporate site-specific costs and the latest available information about worker productivity in decommissioning.

An activity duration critical path is used to determine the total decommissioning program schedule. This is required for calculating the carrying costs, which include program management, administration, field engineering, equipment rental, quality assurance, and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

The estimates also reflect lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997. In addition, the planning and engineering for the Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, San Onofre and Vermont Yankee nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

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10 T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986

Contingency

Consistent with cost estimating practice, contingencies are applied to the decontamination and dismantling costs developed as "specific provision for unforeseeable elements of cost within the defined project scope, particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur."[11] The cost elements in the estimates are based on ideal conditions; therefore, the types of unforeseeable events that are almost certain to occur in decommissioning, based on industry experience, are addressed through a percentage contingency applied on a line-item basis. This contingency factor is a nearly universal element in all large-scale construction and demolition projects. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

Contingency funds are expected to be fully expended throughout the program. As such, inclusion of contingency is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks.

Low-Level Radioactive Waste Disposal

The contaminated and activated material generated in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level (radioactive) waste, although not all of the material is suitable for "shallow-land" disposal. With the passage of the "Low-Level Radioactive Waste Policy Act" in 1980,[12] and its Amendments of 1985,[13] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders.

South Carolina is a member of the three-state Atlantic Interstate Low-Level Radioactive Waste Management Compact, formed after South Carolina formally joined the Northeast Regional Compact. The Barnwell Low-Level Radioactive Waste Management Facility, located in South Carolina, is expected to be available to support the decommissioning of VCSNS. As such, the rate schedule for the Barnwell facility is used to generate disposal costs for the higher activity waste forms waste (Class A containerized waste, large components and Class B and C material[14]). It is also

11 Project and Cost Engineers' Handbook, Second Edition, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, p. 239

12 "Low-Level Radioactive Waste Policy Act of 1980," Public Law 96-573, 1980

13 "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, 1986

14 U.S. Code of Federal Regulations, Title 10, Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste"

assumed that the owners can access other disposal sites, should it prove cost-effective. Low activity waste forms (concrete debris, dry-active waste) and metallic waste suspected of being contaminated are routed to a Tennessee-based radioactive waste processor for decontamination, volume reduction and/or disposal.

The dismantling of the components residing closest to the reactor core generates radioactive waste considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and either stored on site or shipped directly to a DOE facility as it is generated (depending upon the timing of the decommissioning and whether the spent fuel has been removed from the site prior to the start of decommissioning).

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This waste can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to isolate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

<u>High-Level Radioactive Waste Management</u>

Congress passed the "Nuclear Waste Policy Act" (NWPA) in 1982, assigning the federal government's long-standing responsibility for disposal of the spent nuclear fuel created by the commercial nuclear generating plants to the DOE. The DOE was to begin accepting spent fuel by January 31, 1998; however, to date no progress in the removal of spent fuel from commercial generating sites has been made.

Today, the country is at an impasse on high-level waste disposal, even with the License Application for a geologic repository submitted by the DOE to the NRC in

2008. The current administration has cut the budget for the repository program while promising to "conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle … and make recommendations for a new plan."[15] Towards this goal, the administration appointed a Blue Ribbon Commission on America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter includes a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[16]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of recommendations on nuclear waste disposal. Two of the recommendations that may impact decommissioning planning are:

- "[T]he United States [should] establish a program that leads to the timely development of one or more consolidated storage facilities"[17]
- "[T]he United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste."[18]

In January 2013, the DOE issued the "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," in response to the recommendations made by the Blue Ribbon Commission and as "a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel..."[19]

"With the appropriate authorizations from Congress, the Administration currently plans to implement a program over the next 10 years that:

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15 Charter of the Blue Ribbon Commission on America's Nuclear Future, "Objectives and Scope of Activities," http://www.brc.gov/index.php?q=page/charter

16 Ibid.

17 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," http://www.brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf, p. 32, January 2012

18 Ibid., p.27

19 "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."[20]

The NRC's review of DOE's license application to construct a geologic repository at Yucca Mountain was suspended in 2011 when the Administration significantly reduced the budget for completing that work. However, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus (in August 2013)[21] ordering NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application to the extent allowed by previously appropriated funding for the review. That review is now complete with the publication of the five-volume safety evaluation report. A supplement to DOE's environmental impact statement and adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

Completion of the decommissioning process is dependent upon the DOE's ability to remove spent fuel from the site in a timely manner. DOE's repository program assumes that spent fuel allocations will be accepted for disposal from the nation's commercial nuclear plants, with limited exceptions, in the order (the "queue") in which it was discharged from the reactor.[22]

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[20] Ibid., p.2

[21] U.S. Court of Appeals for the District Of Columbia Circuit, In Re: Aiken County, et al, Aug. 2013,http://www.cadc.uscourts.gov/internet/opinions.nsf/BAE0CF34F762EBD985257BC6004DEB18/$file/11-1271-1451347.pdf

[22] In 2008, the DOE issued a report to Congress in which it concluded that it did not have authority, under present law, to accept spent nuclear fuel for interim storage from decommissioned commercial nuclear power reactor sites. However, the Blue Ribbon Commission, in its final report, noted that: "[A]ccepting spent fuel according to the OFF [Oldest Fuel First] priority ranking instead of giving priority to shutdown reactor sites could greatly reduce the cost savings that could be achieved through consolidated storage if priority could be given to accepting spent fuel from shutdown reactor sites before accepting fuel from still-operating plants. …. The magnitude of the cost savings that could be achieved by giving priority to shutdown sites appears to be large enough (i.e., in the billions of dollars) to warrant DOE exercising its right under the Standard Contract to move this fuel first." For planning purposes only, the estimates do not assume that VCSNS, as a permanently shutdown unit, will receive priority; the fuel removal schedule assumed in this estimate is based upon DOE acceptance of fuel according to the "Oldest Fuel

For purposes of this analysis, the spent fuel management plan for 2042 shutdown scenarios assumes "just-in-time" acceptance, i.e., the DOE will be able to complete the transfer of spent fuel so as not to impede a deferred decommissioning scenario (SAFSTOR-1) and the termination of the operating license within the required 60 year period (from the cessation of operations). To achieve this objective, based upon the oldest fuel receiving the highest priority and an annual maximum rate of transfer of 3,000 metric tons of uranium, DOE would commence pickup of spent fuel from commercial generators no later than 2054, with fuel completely removed from the site by 2095 (the year prior to reactivation of the site and the start of deferred decommissioning). Different DOE acceptance schedules may result in different completion dates.

The spent fuel management plan for the SAFSTOR-2 scenario assumes the same DOE start date (2054) as the DECON and SAFSTOR-1 scenarios. Assuming that VCSNS operates until 2062, DOE will begin removing spent fuel from the site eight years prior to the cessation of plant operations and throughout the seven years of post-shutdown spent fuel pool operations. The estimate assumes that ISFSI campaigns during plant operations are suspended once DOE begins to remove fuel from the site and that the additional dry storage systems required post-shutdown to empty the pool are significantly reduced by the DOE performance.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all irradiated fuel at the reactor site until title of the fuel is transferred to the DOE.[23] Interim storage of the fuel, until the DOE has completed the transfer, will be at an on-site ISFSI.

An ISFSI, operated under a Part 50 General License (in accordance with 10 CFR 72, Subpart K[24]), is being constructed to support continued plant operations. The facility is assumed to be available to support future decommissioning operations. As such, following the final cessation of plant operations, the fuel from the wet storage pool, including the final core, is either transferred to the DOE or packaged for interim storage at the ISFSI (depending upon the shutdown date assumed). Once the fuel handling building's wet storage pool is emptied, the building can be either decontaminated and dismantled or prepared for long-term storage.

First" priority ranking. The plant owners will seek the most expeditious means of removing fuel from the site when DOE commences performance.

23 U.S. Code of Federal Regulations, Title 10, Part 50 – Domestic Licensing of Production and Utilization Facilities, Subpart 54 (bb), "Conditions of Licenses"

24 U.S. Code of Federal Regulations, Title 10, Part 72, Subpart K, "General License for Storage of Spent Fuel at Power Reactor Sites"

SCE&G's position is that the DOE has a contractual obligation to accept the spent fuel earlier than the projections set out above consistent with its contract commitments. No assumption made in this study should be interpreted to be inconsistent with this claim. However, at this time, including the cost of storing spent fuel in this study is the most reasonable approach because it insures the availability of sufficient decommissioning funds at the end of the station's life if, contrary to its contractual obligation, the DOE has not performed earlier. The cost for the interim storage of spent fuel has been calculated and is separately presented as "Spent Fuel Management" expenditures in this report.

Site Restoration

The efficient removal of the contaminated materials at the site may result in damage to many of the site structures. Blasting, coring, drilling, and the other decontamination activities can substantially damage power block structures, potentially weakening the footings and structural supports. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures with a work force already mobilized is more efficient and less costly than if the process is deferred. Experience at shutdown generating stations has shown that plant facilities quickly degrade without maintenance, adding additional expense and creating potential hazards to the public and the demolition work force.

This estimate assumes that some site features will remain following the decommissioning project. These include the existing electrical switchyard, which is assumed to remain functional in support of the regional electrical distribution system. The existing shoreline will also be left intact.

Consequently, this study assumes that site structures addressed by this analysis are removed to a nominal depth of three feet below the local grade level wherever possible. The site is then graded and stabilized. The cost for the site restoration of non-essential and/or non-contaminated structures has been calculated and is separately presented as "Site Restoration" expenditures in this report.

Summary

The estimates to decommission VCSNS assume the removal of all contaminated and activated plant components and structural materials such that the owners may then have unrestricted use of the site with no further requirements for an operating license. Low-level radioactive waste, other than GTCC waste, is sent to a commercial processor for treatment/conditioning or to a controlled disposal facility.

Decommissioning is accomplished within the 60-year period required by current NRC regulations. In the interim, the spent fuel remains in storage at the site until such time that the transfer to a DOE facility is complete.

The alternatives evaluated in this analysis are described in Section 2. The assumptions are presented in Section 3, along with schedules of annual expenditures. The major cost contributors are identified in Section 6, with detailed activity costs, waste volumes, and associated manpower requirements delineated in Appendices C through F. The major cost components are also identified in the cost summary provided at the end of this section.

The cost elements in the estimates for the DECON and SAFSTOR alternatives are assigned to one of three subcategories: NRC License Termination (radiological remediation), Spent Fuel Management, and Site Restoration. The subcategory "NRC License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). The cost reported for this subcategory is generally sufficient to terminate the plant's operating license, recognizing that there may be some additional cost impact from spent fuel management. The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). Section 3.4.1 provides the basis for the ISFSI decommissioning cost delineated in Appendix F.

The "Spent Fuel Management" subcategory contains costs associated with the containerization and transfer of spent fuel from the wet storage pool to the ISFSI for interim storage, and/or directly to the DOE (SAFSTOR-2), as well as the eventual transfer of the spent fuel in storage at the ISFSI to the DOE. Costs are included for the operation of the storage pool and the management of the ISFSI until such time that the transfer is complete. It does not include any spent fuel management expenses incurred prior to the cessation of plant operations, nor does it include any costs related to the final disposal of the spent fuel.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are removed to a depth of three feet and backfilled to conform to local grade.

It should be noted that the costs assigned to these subcategories are allocations. Delegation of cost elements is for the purposes of comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., Asset Retirement Obligation determinations). In reality, there can be considerable interaction between the activities in the three subcategories. For example, selected non-contaminated structures may be removed early in the project to improve access to highly contaminated facilities or plant components. In these instances, the non-contaminated removal costs could be reassigned from Site Restoration to an NRC License Termination support activity. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost, if executed as described.

As noted within this document, the estimates were developed and costs are presented in 2016 dollars. As such, the estimates do not reflect the escalation of costs (due to inflationary and market forces) over the remaining operating life of the plant or during the decommissioning period.

DECON COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2016 dollars)

Cost Element	Cost
Decontamination	11,582
Removal	121,160
Packaging	25,330
Transportation	6,625
Waste Disposal	71,130
Off-site Waste Processing	8,306
Program Management [1]	319,191
Site Security	196,113
Spent Fuel Pool Isolation	13,062
Spent Fuel (Direct Expenditures) [2]	192,320
Insurance and Regulatory Fees	46,838
Energy	15,468
Characterization and Licensing Surveys	25,590
Property Taxes	14,921
Miscellaneous Equipment / Site Services	7,499
Corporate Overhead	23,031
Non-Labor Overhead	10,600
Total [3]	1,108,765

Cost Element	Cost
License Termination	629,138
Spent Fuel Management	413,016
Site Restoration	66,611
Total [3]	1,108,765

[1] Includes engineering costs

[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer/spent fuel pool O&M and EP fees

[3] Columns may not add due to rounding

SAFSTOR-1 COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2016 dollars)

Cost Element	Cost
Decontamination	13,671
Removal	123,209
Packaging	18,934
Transportation	6,075
Waste Disposal	60,233
Off-site Waste Processing	8,765
Program Management [1]	379,778
Site Security	237,464
Spent Fuel Pool Isolation	13,062
Spent Fuel (Direct Expenditures) [2]	174,982
Insurance and Regulatory Fees	65,519
Energy	26,092
Characterization and Licensing Surveys	25,950
Property Taxes	14,921
Miscellaneous Equipment / Site Services	31,189
Corporate Overhead	31,163
Non-Labor Overhead	14,223
Total [3]	1,245,229

Cost Element	Cost
License Termination	794,764
Spent Fuel Management	384,354
Site Restoration	66,111
Total [3]	1,245,229

[1] Includes engineering costs

[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer/spent fuel pool O&M and EP fees

[3] Columns may not add due to rounding

SAFSTOR-2 COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2016 dollars)

Cost Element	Cost
Decontamination	13,671
Removal	123,031
Packaging	18,930
Transportation	6,074
Waste Disposal	60,558
Off-site Waste Processing	8,765
Program Management [1]	369,934
Site Security	221,835
Spent Fuel Pool Isolation	13,062
Spent Fuel (Direct Expenditures) [2]	143,595
Insurance and Regulatory Fees	65,219
Energy	25,876
Characterization and Licensing Surveys	25,950
Property Taxes	8,085
Miscellaneous Equipment / Site Services	31,189
Corporate Overhead	30,098
Non-Labor Overhead	13,773
Total [3]	1,179,646

Cost Element	Cost
License Termination	787,916
Spent Fuel Management	325,619
Site Restoration	66,111
Total [3]	1,179,646

[1] Includes engineering costs

[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer/spent fuel pool O&M and EP fees

[3] Columns may not add due to rounding

1. INTRODUCTION

This report presents estimates of the cost to decommission the Virgil C. Summer Nuclear Station (VCSNS) for the selected decommissioning scenarios following the scheduled cessation of plant operations. The current estimates are designed to provide South Carolina Electric & Gas Company, (SCE&G) and South Carolina Public Service Authority (Santee Cooper), the plant's owners, with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear unit.

The analysis relies upon site-specific, technical information from an earlier evaluation prepared in 2012,[1]* updated to reflect current assumptions pertaining to the disposition of the nuclear plant and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but rather estimates prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission VCSNS; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, were reviewed for this analysis. The following structures were added to the 2012 inventory: FLEX storage building, emergency response building, and combined maintenance shop.

1.1 OBJECTIVES OF STUDY

The objectives of this study are to prepare comprehensive estimates of the costs to decommission VCSNS, to provide a sequence or schedule for the associated activities, and to develop waste stream projections from the decontamination and dismantling activities.

VCSNS is owned by SCE&G (two-thirds) and Santee Cooper (one-third). SCE&G is a wholly-owned subsidiary of SCANA Corporation and has exclusive responsibility and control over the operation and maintenance of the nuclear unit. In August of 2002, SCE&G submitted an application to the NRC for

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* References provided in Section 7 of the document

renewal of VCSNS's operating license (originally set to expire on August 6, 2022). The NRC approved the application on April 23, 2004, extending the term of the license an additional 20 years to August 6, 2042.

The NRC is anticipating that licensees will consider extending the operation of their nuclear power plants beyond the 60-year license renewal period and has drafted a standard review plan for such applications (NUREG-2192). It is assumed, for purposes of this study, that SCE&G will submit a "subsequent renewal application" during VCSNS's currently licensed operating life. Approval would extend permissible reactor operations to 80 years. Under this scenario, the cessation of plant operations would be August 6, 2062.

1.2 SITE DESCRIPTION

The nuclear unit is located in Fairfield County, South Carolina, approximately 26 miles northwest of Columbia. The plant site is adjacent to the manmade Monticello Reservoir which provides water requirements to the nuclear plant and a nearby pumped storage facility.

The nuclear steam supply system (NSSS), provided by the Westinghouse Electric Corporation, consists of a pressurized water reactor and a three-loop reactor coolant system (each loop with a steam generator and a reactor coolant pump). The licensed rating of the unit is 2,900 MWt. The equivalent station net electrical output is 966 MWe.

The NSSS is housed within a seismic Category I pre-stressed concrete containment structure. The containment is a steel-lined, vertical right cylindrical structure with a shallow dome roof and flat base. A welded carbon steel liner plate, anchored to the inside face of the containment, serves as a leaktight membrane.

Heat produced in the reactor is converted to electrical energy by the steam and power conversion system. A turbine-generator system converts the thermal energy of steam produced in the steam generators into mechanical shaft power and then into electrical energy. The plant's turbine-generator is a General Electric 1,800 rpm, tandem compound, four-flow, reheat unit. It consists of one high-pressure, double-flow element and two low-pressure, double-flow elements. The turbine is operated in a closed feedwater cycle which condenses the steam; the heated feedwater is returned to the steam generators. Heat rejected in the main condensers is removed by the circulating water system. The system provides the heat sink required for removal of waste heat in the power plant's thermal cycle through the plant's main condenser. Water is withdrawn from the Monticello Reservoir by three circulating water pumps located in the circulating discharge structure. The discharge from the pumps is routed into the main supply line to the plant. The main condensers are supplied with cooling water through branches from the main circulating supply line.

1.3 REGULATORY GUIDANCE

The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule "General Requirements for Decommissioning Nuclear Facilities," issued in June 1988.[2] This rule set forth financial criteria for decommissioning licensed nuclear power facilities. The regulation addressed decommissioning planning needs, timing, funding methods, and environmental review requirements. The intent of the rule was to ensure that decommissioning would be accomplished in a safe and timely manner and that adequate funds would be available for this purpose. Subsequent to the rule, the NRC issued Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors,"[3] which provided additional guidance to the licensees of nuclear facilities on the financial methods acceptable to the NRC staff for complying with the requirements of the rule. The regulatory guide addressed the funding requirements and provided guidance on the content and form of the financial assurance mechanisms indicated in the rule.

The rule defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB. The DECON alternative assumes that any contaminated or activated portion of the plant's systems, structures and facilities are removed or decontaminated to levels that permit the site to be released for unrestricted use shortly after the cessation of plant operations, while the SAFSTOR and ENTOMB alternatives defer the process.

The rule also placed limits on the time allowed to complete the decommissioning process. For all alternatives, the process is restricted in overall duration to 60 years, unless it can be shown that a longer duration is necessary to protect public health and safety. At the conclusion of a 60-year dormancy period (or longer if the NRC approves such a case), the site would still require significant remediation to meet the unrestricted release limits for license termination.

The ENTOMB alternative has not been viewed as a viable option for power reactors due to the significant time required to isolate the long-lived radionuclides for decay to permissible levels. However, with rulemaking permitting the controlled release of a site,[4] the NRC did re-evaluate the alternative. The resulting feasibility study, based upon an assessment by

Pacific Northwest National Laboratory, concluded that the method did have conditional merit for some, if not most reactors. The staff also found that additional rulemaking would be needed before this option could be treated as a generic alternative.

The NRC had considered rulemaking to alter the 60-year time for completing decommissioning and to clarify the use of engineered barriers for reactor entombments.[5] However, the NRC's staff has subsequently recommended that rulemaking be deferred, based upon several factors (e.g., no licensee has committed to pursuing the entombment option, the unresolved issues associated with the disposition of greater-than-Class C material (GTCC), and the NRC's current priorities), at least until after the additional research studies are complete. The Commission concurred with the staff's recommendation.

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants.[6] When the decommissioning regulations were adopted in 1988, it was assumed that the majority of licensees would decommission at the end of the facility's operating licensed life. Since that time, several licensees permanently and prematurely ceased operations. Exemptions from certain operating requirements were required once the reactor was defueled to facilitate the decommissioning. Each case was handled individually, without clearly defined generic requirements. The NRC amended the decommissioning regulations in 1996 to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The amendments allow for greater public participation and better define the transition process from operations to decommissioning.

Under the revised regulations, licensees will submit written certification to the NRC within 30 days after the decision to cease operations. Certification will also be required once the fuel is permanently removed from the reactor vessel. Submittal of these notices, along with related changes to Technical Specifications, entitle the licensee to a fee reduction and eliminate the obligation to follow certain requirements needed only during operation of the reactor. Within two years of submitting notice of permanent cessation of operations, the licensee is required to submit a Post-Shutdown Decommissioning Activities Report (PSDAR) to the NRC. The PSDAR describes the planned decommissioning activities, the associated sequence and schedule, and an estimate of expected costs. Prior to completing decommissioning, the licensee is required to submit an application to the NRC to terminate the license, which includes a license termination plan (LTP).

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[7] The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details, including an ISFSI decommissioning estimate, are included in this analysis.

1.3.1 High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act"[8] (NWPA) in 1982, assigning the federal government's long-standing responsibility for disposal of the spent nuclear fuel created by the commercial nuclear generating plants to the DOE. It was to begin accepting spent fuel by January 31, 1998; however, to date no progress in the removal of spent fuel from commercial generating sites has been made.

Today, the country is at an impasse on high-level waste disposal, even with the License Application for a geologic repository submitted by the DOE to the NRC in 2008. The current administration has cut the budget for the repository program while promising to "conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle … and make recommendations for a new plan." Towards this goal, the administration appointed a Blue Ribbon Commission on America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter includes a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[9]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of recommendations on nuclear waste disposal. Two of the recommendations that may impact decommissioning planning are:

- "[T]he United States [should] establish a program that leads to the timely development of one or more consolidated storage facilities"

- "[T]he United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste"[10]

In January 2013, the DOE issued the "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," in response to the recommendations made by the Blue Ribbon Commission and as "a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel..."[11]

"With the appropriate authorizations from Congress, the Administration currently plans to implement a program over the next 10 years that:

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."

The NRC's review of DOE's license application to construct a geologic repository at Yucca Mountain was suspended in 2011 when the Administration significantly reduced the budget for completing that work. However, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus (in August 2013)[12] ordering NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application to the extent allowed by previously appropriated funding for the review. That review is now complete with the publication of the five-volume safety evaluation report. A supplement to DOE's environmental impact statement and adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

Completion of the decommissioning process is dependent upon the DOE's ability to remove spent fuel from the site in a timely manner. DOE's repository program assumes that spent fuel allocations will be accepted for disposal from the nation's commercial nuclear plants, with limited exceptions, in the order (the "queue") in which it was discharged from the reactor.[13]

For purposes of this analysis, the spent fuel management plan for 2042 shutdown scenarios assumes "just-in-time" acceptance, i.e., the DOE will be able to complete the transfer of spent fuel so as not to impede a deferred decommissioning scenario (SAFSTOR-1) and the termination of the operating license within the required 60 year period (from the cessation of operations). To achieve this objective, based upon the oldest fuel receiving the highest priority and an annual maximum rate of transfer of 3,000 metric tons of uranium, DOE would commence pickup of spent fuel from commercial generators no later than 2054, with fuel completely removed from the site by 2095 (the year prior to reactivation of the site and the start of deferred decommissioning). Different DOE acceptance schedules may result in different completion dates.

The spent fuel management plan for the SAFSTOR-2 scenario assumes the same DOE start date (2054) as the DECON and SAFSTOR-1 scenarios. Assuming that VCSNS operates until 2062, DOE will begin removing spent fuel from the site eight years prior to the cessation of plant operations and throughout the seven years of post-shutdown spent fuel pool operations. The estimate assumes that ISFSI campaigns during plant operations are suspended once DOE begins to remove fuel from the site and that the additional dry storage systems required post-shutdown to empty the pool are significantly reduced by the DOE performance.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all irradiated fuel at the reactor site until title of the fuel is transferred to the DOE.[14] Interim storage of the fuel, until the DOE has completed the transfer, will be at an on-site ISFSI.

An ISFSI, operated under a Part 50 General License (in accordance with 10 CFR 72, Subpart K[15]), is being constructed to support continued plant operations. The facility is assumed to be available to support future decommissioning operations. As such, following the final cessation of plant operations, the fuel from the wet storage pool, including the final core, is either transferred to the DOE or packaged for interim storage at the ISFSI (depending upon the shutdown date assumed). Once the fuel handling building's wet storage pool is emptied, the building can be either decontaminated and dismantled or prepared for long-term storage.

SCE&G's position is that the DOE has a contractual obligation to accept the spent fuel earlier than the projections set out above consistent with its contract commitments. No assumption made in this study should be interpreted to be inconsistent with this claim. However, at this time, including the cost of storing spent fuel in this study is the most reasonable approach because it insures the availability of sufficient decommissioning funds at the end of the station's life if, contrary to its contractual obligation, the DOE has not performed earlier.

1.3.2 Low-Level Radioactive Waste Disposal

The contaminated and activated material generated in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level (radioactive) waste, although not all of the material is suitable for "shallow-land" disposal. With the passage of the "Low-Level Radioactive Waste Policy Act" in 1980,[16] and its Amendments of 1985,[17] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders.

South Carolina is a member of the three-state Atlantic Interstate Low-Level Radioactive Waste Management Compact, formed after South Carolina formally joined the Northeast Regional Compact. The Barnwell Low-Level Radioactive Waste Management Facility, located in South Carolina, is expected to be available to support the decommissioning of VCSNS. As such, the rate schedule for the Barnwell facility is used to generate disposal costs for the higher activity waste forms waste (Class A containerized waste, large components and Class B and C material[18]). It is also assumed that the owners can access other disposal sites, should it prove cost-effective. Low activity waste forms (concrete debris, dry-active waste) and metallic waste suspected of being contaminated are routed to a Tennessee-based radioactive waste processor for decontamination, volume reduction and/or disposal.

The dismantling of the components residing closest to the reactor core generates radioactive waste considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and either stored on site or shipped directly to a DOE facility as it is generated (depending upon the timing of the decommissioning and whether the spent fuel has been removed from the site prior to the start of decommissioning).

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This waste can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to isolate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

1.3.3 Radiological Criteria for License Termination

In 1997, the NRC published Subpart E, "Radiological Criteria for License Termination,"[19] amending 10 CFR Part 20. This subpart provides radiological criteria for releasing a facility for unrestricted use. The regulation states that the site can be released for unrestricted use if radioactivity levels are such that the average member of a critical group would not receive a Total Effective Dose Equivalent (TEDE) in excess of 25 millirem per year, and provided that residual radioactivity has been reduced to levels that are As Low As Reasonably Achievable (ALARA). The decommissioning estimates assume that the VCSNS site will be remediated to a residual level consistent with the NRC-prescribed level.

It should be noted that the NRC and the Environmental Protection Agency (EPA) differ on the amount of residual radioactivity considered acceptable in site remediation. The EPA has two limits that apply to radioactive materials. An EPA limit of 15 millirem per year is derived from criteria established by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[20] An additional and separate limit of 4 millirem per year, as defined in 40 CFR §141.16, is applied to drinking water.[21]

On October 9, 2002, the NRC signed an agreement with the EPA on the radiological decommissioning and decontamination of NRC-licensed sites. The Memorandum of Understanding (MOU)[22] provides that EPA will defer exercise of authority under CERCLA for the majority of facilities decommissioned under NRC authority. The MOU also includes provisions for NRC and EPA consultation for certain sites when, at the time of license termination, (1) groundwater contamination exceeds EPA-permitted levels; (2) NRC contemplates restricted release of the site; and/or (3) residual radioactive soil concentrations exceed levels defined in the MOU.

The MOU does not impose any new requirements on NRC licensees and should reduce the involvement of the EPA with NRC licensees who are decommissioning. Most sites are expected to meet the NRC criteria for unrestricted use, and the NRC believes that only a few sites will have groundwater or soil contamination in excess of the levels specified in the MOU that trigger consultation with the EPA. However, if there are other hazardous materials on the site, the EPA may be involved in the cleanup. As such, the possibility of dual regulation remains for certain licensees. The present study does not include any costs for this occurrence.

2. DECOMMISSIONING ALTERNATIVES

Detailed cost estimates were developed to decommission VCSNS based upon the NRC-approved decommissioning alternatives DECON and SAFSTOR. Although the alternatives differ with respect to technique, process, cost, and schedule, they attain the same result: the ultimate release of the site for unrestricted use.

Three decommissioning scenarios were evaluated for the VCSNS nuclear unit. The scenarios selected are representative of alternatives available to the owners and are defined as follows:

1. The first scenario assumes that plant would be promptly decommissioned (DECON alternative) upon the expiration of the current operating license, i.e., in 2042. The spent fuel is relocated to the ISFSI for interim storage and to facilitate the decontamination and dismantling of the power block structures. The ISFSI will remain operational, after the plant is decommissioned, until the transfer of the spent fuel to the DOE is complete (approximately 53 years after the cessation of operations for the purpose of this estimate).

2. The second scenario assumes that the plant is placed into safe-storage (SAFSTOR alternative) upon the expiration of the current operating license, i.e., in 2042. The spent fuel is relocated to the ISFSI for interim storage and so that the plant systems can be drained and de-energized. Decommissioning is deferred until the spent fuel is removed from the site (approximately 53 years after the cessation of operations, consistent with the DECON alternative). The license is terminated within the required 60-year period. This alternative is designated SAFSTOR-1.

3. The third scenario assumes that the plant operates an additional 20 years. It also assumes that the plant is placed into safe-storage (SAFSTOR alternative) at the conclusion of the extended operating period, i.e., in 2062. Spent fuel remaining in the storage pool that has not been transferred to the DOE (based upon the start date assumed in Scenarios 1 and 2), is relocated to the ISFSI. The ISFSI will remain operational until the transfer of the spent fuel to the DOE is complete (approximately 47 years after the cessation of operations). The plant will remain in storage for another 7 years after the fuel is removed from the site at which time decommissioning will commence. The license is terminated within the required 60-year period. This alternative is designated SAFSTOR-2.

The following sections describe the basic activities associated with each alternative. Although detailed procedures for each activity identified are not provided, and the actual sequence of work may vary, the activity descriptions provide a basis not only for estimating but also for the expected scope of work, i.e., engineering and planning at the time of decommissioning.

The conceptual approach that the NRC has described in its regulations divides decommissioning into three phases. The initial phase commences with the effective date of permanent cessation of operations and involves the transition of both plant and licensee from reactor operations (i.e., power production) to facility de-activation and closure. During the first phase, notification is to be provided to the NRC certifying the permanent cessation of operations and the removal of fuel from the reactor vessel. The licensee is then prohibited from reactor operation.

The second phase encompasses activities during the storage period or during major decommissioning activities, or a combination of the two. The third phase pertains to the activities involved in license termination. The decommissioning estimates developed for VCSNS are also divided into phases or periods; however, demarcation of the phases is based upon major milestones within the project or significant changes in the projected expenditures.

2.1 DECON

The DECON alternative, as defined by the NRC, is "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." This study does not address the cost to dispose of the spent fuel residing at the site; such costs are funded through a surcharge on electrical generation. However, the study does estimate the costs incurred with the interim on-site storage of the fuel pending shipment by the DOE to an off-site disposal facility. Those costs are separately presented as "Spent Fuel Management Expenditures" in this report.

2.1.1 Period 1 - Preparations

In anticipation of the cessation of plant operations, detailed preparations are undertaken to provide a smooth transition from plant operations to site decommissioning. Through implementation of a staffing transition plan, the organization required to manage the intended decommissioning activities is assembled from available plant staff and outside resources. Preparations include the planning for permanent defueling of the reactor, revision of technical specifications applicable to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

Engineering and Planning

The PSDAR, required prior to or within two years of permanent cessation of operations, provides a description of the licensee's planned decommissioning activities, a timetable, a site-specific decommissioning cost estimate, and the associated financial requirements of the intended decommissioning program. Upon receipt of the PSDAR, the NRC will make the document available to the public for comment in a local hearing to be held in the vicinity of the reactor site. Ninety days following submittal and NRC receipt of the PSDAR, the licensee may begin to perform major decommissioning activities under a modified 10 CFR §50.59 procedure, i.e., without specific NRC approval. Major activities are defined as any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components (for shipment) containing GTCC, as defined by 10 CFR §61. Major components are further defined as comprising the reactor vessel and internals, large bore reactor coolant system piping, and other large components that are radioactive. The NRC includes the following additional criteria for use of the §50.59 process in decommissioning. The proposed activity must not:

- foreclose release of the site for possible unrestricted use,
- significantly increase decommissioning costs,
- cause any significant environmental impact, or
- violate the terms of the licensee's existing license

Existing operational technical specifications are reviewed and modified to reflect plant conditions and the safety concerns associated with permanent cessation of operations. The environmental impact associated with the planned decommissioning activities is also considered. Typically, a licensee will not be allowed to proceed if the consequences of a particular decommissioning activity are greater than that bounded by previously evaluated environmental assessments or impact statements. In this instance, the licensee would have to submit a license amendment for the specific activity and update the environmental report.

The decommissioning program outlined in the PSDAR will be designed to accomplish the required tasks within the ALARA guidelines (as defined in 10 CFR §20) for protection of personnel from exposure to radiation hazards. It will also address the continued protection of the health and safety of the public and the environment during the dismantling activity. Consequently, with the development of the

PSDAR, activity specifications, cost-benefit and safety analyses, work packages, and procedures, would be assembled to support the proposed decontamination and dismantling activities.

Site Preparations

Following final plant shutdown, and in preparation for actual decommissioning activities, the following activities are initiated:

- Characterization of the site and surrounding environs. This includes radiation surveys of work areas, major components (including the reactor vessel and its internals), internal piping, and biologic shield cores.
- An ISFSI is being constructed to support continued plant operation and will need to be expanded following the cessation of operations to offload the spent fuel pool in support of the decommissioning program.
- Isolation of the spent fuel storage pool and fuel handling systems, such that decommissioning operations can commence on the balance of the plant. The pool will remain operational for approximately seven years following the cessation of operations. During this time period, it is assumed that the spent fuel residing in the pool that cannot be directly transferred to the DOE will be moved to an ISFSI for interim storage.
- Specification of transport and disposal requirements for activated materials and/or hazardous materials, including shielding and waste stabilization.
- Development of procedures for occupational exposure control, control and release of liquid and gaseous effluent, processing of radwaste (including dry-active waste, resins, filter media, metallic and non-metallic components generated in decommissioning), site security and emergency programs, and industrial safety.

2.1.2 Period 2 - Decommissioning Operations

This period includes the physical decommissioning activities associated with the removal and disposal of contaminated and activated components and structures, including the successful release of the site from the 10 CFR §50 operating license, exclusive of the ISFSI. Significant decommissioning activities in this phase include:

- Construction of temporary facilities and/or modification of existing facilities to support dismantling activities. For example, this will include a centralized processing area to facilitate equipment removal and component preparations for off-site disposal.
- Reconfiguration and modification of site structures and facilities as needed to support decommissioning operations. This will include the upgrading of roads (on- and off-site) to facilitate hauling and transport. Modifications will be required to the containment structure to facilitate access of large/heavy equipment. Modifications will also be required to the refueling area of the building to support the segmentation of the reactor vessel internals and component extraction.
- Transfer of the spent fuel from the storage pool to the ISFSI pad.
- Design and fabrication of temporary and permanent shielding to support removal and transportation activities, construction of contamination control envelopes, and the procurement of specialty tooling.
- Procurement (lease or purchase) of shipping casks, cask liners, and industrial packages.
- Decontamination of components and piping systems as required to control (minimize) worker exposure.
- Removal of piping and components no longer essential to support decommissioning operations.
- Removal of control rod drive housings and the head service structure from reactor vessel head. Segmentation of the vessel closure head.
- Removal and segmentation of the upper internals assemblies. Segmentation will maximize the loading of the shielded transport casks, i.e., by weight and activity. The operations are conducted under water using remotely operated tooling and contamination controls.
- Disassembly and segmentation of the remaining reactor internals, including the core former and lower core support assembly. Some material is expected to exceed Class C disposal requirements. As such, the segments will be packaged in modified fuel storage canisters for geologic disposal.
- Segmentation of the reactor vessel. A shielded platform is installed for segmentation as cutting operations are performed in-air using remotely operated equipment within a contamination control envelope. The water level is maintained just below the cut to

minimize the working area dose rates. Segments are transferred in-air to containers that are stored under water, for example, in an isolated area of the refueling canal.

- Removal of the activated portions of the concrete biological shield and accessible contaminated concrete surfaces. If dictated by the steam generator and pressurizer removal scenarios, those portions of the associated cubicles necessary for access and component extraction are removed.
- Removal of the steam generators and pressurizer for material recovery and controlled disposal. These components can serve as their own burial containers provided that all penetrations are properly sealed and the internal contaminants are stabilized, e.g., with grout. Steel shielding will be added, as necessary, to those external areas of the package to meet transportation limits and regulations.
- Spent fuel storage operations continue throughout the active decommissioning period.

At least two years prior to the anticipated date of license termination, an LTP is required. Submitted as a supplement to the Final Safety Analysis Report (FSAR) or its equivalent, the plan must include: a site characterization, description of the remaining dismantling activities, plans for site remediation, procedures for the final radiation survey, designation of the end use of the site, an updated cost estimate to complete the decommissioning, and any associated environmental concerns. The NRC will notice the receipt of the plan, make the plan available for public comment, and schedule a local hearing. LTP approval will be subject to any conditions and limitations as deemed appropriate by the Commission. The licensee may then commence with the final remediation of site facilities and services, including:

- Removal of remaining plant systems and associated components as they become nonessential to the decommissioning program or worker health and safety (e.g., waste collection and treatment systems, electrical power and ventilation systems).
- Removal of the steel liners from refueling canal and spent fuel storage pool, disposing of the activated and contaminated sections as radioactive waste. Removal of any activated/ contaminated concrete.
- Surveys of the decontaminated areas of the containment structure.

- Remediation and removal of the contaminated equipment and material from the auxiliary and fuel buildings and any other contaminated facility. Radiation and contamination controls will be utilized until residual levels indicate that the structures and equipment can be released for unrestricted access and conventional demolition. This activity may necessitate the dismantling and disposition of most of the systems and components (both clean and contaminated) located within these buildings. This activity facilitates surface decontamination and subsequent verification surveys required prior to obtaining release for demolition.
- Removal of the remaining components, equipment, and plant services in support of the area release survey(s).
- Routing of material removed in the decontamination and dismantling to a central processing area. Material certified to be free of contamination is released for unrestricted disposition, e.g., as scrap, recycle, or general disposal. Contaminated material is characterized and segregated for additional off-site processing (disassembly, chemical cleaning, volume reduction, and waste treatment), and/or packaged for controlled disposal at a low-level radioactive waste disposal facility.

Incorporated into the LTP is the Final Survey Plan. This plan identifies the radiological surveys to be performed once the decontamination activities are completed and is developed using the guidance provided in the "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)."[23] This document incorporates the statistical approaches to survey design and data interpretation used by the EPA. It also identifies commercially available instrumentation and procedures for conducting radiological surveys. Use of this guidance ensures that the surveys are conducted in a manner that provides a high degree of confidence that applicable NRC criteria are satisfied. Once the survey is complete, the results are provided to the NRC in a format that can be verified. The NRC then reviews and evaluates the information, performs an independent confirmation of radiological site conditions, and makes a determination on the requested change to the operating license (that would release the property, exclusive of the ISFSI, for unrestricted use).

The NRC will amend the operating license to reduce the licensed area to the ISFSI area if it determines that site remediation has been performed in accordance with the LTP, and that the terminal radiation survey and associated documentation demonstrate that the property (exclusive of the ISFSI) is suitable for release.

2.1.3 Period 3 - Site Restoration

Following completion of decommissioning operations, site restoration activities can begin. Efficient removal of the contaminated materials and verification that residual radionuclide concentrations are below the NRC limits will result in substantial damage to many of the structures. Although performed in a controlled, safe manner, blasting, coring, drilling, scarification (surface removal), and the other decontamination activities will substantially degrade power block structures including the reactor, fuel handling, radioactive waste, solidification facility and condensate polishing buildings. Under certain circumstances, verifying that subsurface radionuclide concentrations meet NRC site release requirements will require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This removal activity will be necessary for those facilities and plant areas where historical records, when available, indicate the potential for radionuclides having been present in the soil, where system failures have been recorded, or where it is required to confirm that subsurface process and drain lines were not breached over the operating life of the station.

It is not currently anticipated that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures with a work force already mobilized on site is more efficient than if the process is deferred.

Dismantling of site structures following decommissioning is clearly the most appropriate and cost-effective option. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The effort to dismantle site structures with a work force already mobilized on site is more efficient than if the process were deferred. Site facilities quickly degrade without maintenance, adding additional expense and creating potential hazards to the public as well as to future workers. Abandonment creates a breeding ground for vermin infestation as well as other biological hazards.

This cost study presumes that site structures and other facilities are dismantled as a continuation of the decommissioning activity. Foundations and exterior walls are removed to a nominal depth of three feet below grade. The three-foot depth allows for the placement of gravel for drainage, as well as topsoil, so that vegetation can be established for erosion control. Site areas affected by the dismantling activities are restored and the plant area graded as required to prevent ponding and inhibit the refloating of subsurface materials.

Non-contaminated concrete rubble produced by demolition activities is processed to remove reinforcing steel and miscellaneous embedments. The processed material is then used on site to backfill foundation voids. Excess non-contaminated materials are trucked to an off-site area for disposal as construction debris.

2.1.4 ISFSI Operations and Decommissioning

For purposes only of this estimate, transfer of spent fuel to a DOE repository or interim facility is assumed to be exclusively from the ISFSI once the fuel pool has been emptied and the fuel handling building released for decommissioning. If this assumption is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers and to dispose of existing containers. The ISFSI will continue to operate under a general license (10 CFR Part 50) following the amendment of the operating license to release the adjacent (power block) property.

Assuming the DOE starts accepting fuel from VCSNS in 2054, transfer of spent fuel from the ISFSI is anticipated to continue through the year 2095. This assumption is made for purposes of this estimate, although it is acknowledged that the plant owner will seek the most expeditious means of removing fuel from the site when DOE commences performance.

At the conclusion of the spent fuel transfer process, the ISFSI will be decommissioned. The Commission will terminate the Part 50 license if it determines that the remediation of the ISFSI has been performed in accordance with an ISFSI license termination plan and that the final radiation survey and associated documentation demonstrate that the facility is suitable for release. Once the requirements are satisfied, the NRC can terminate the license for the ISFSI.

The design of the ISFSI is based upon the use of a multi-purpose canister and a vertical concrete module/overpack for pad storage. It is assumed that once the canisters containing the spent fuel assemblies have been removed, any required decontamination is performed on the storage modules (some minor neutron activation is assumed), and the license for the facility terminated, the modules can be dismantled using conventional techniques for the demolition of reinforced concrete. The concrete storage pad is then removed and the area regraded.

2.2 SAFSTOR

The NRC defines SAFSTOR as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use." The facility is left intact (during the dormancy period), with structures maintained in a sound condition. Systems that are not required to support the spent fuel pool or site surveillance and security are drained, de-energized, and secured. Minimal cleaning/removal of loose contamination and/or fixation and sealing of remaining contamination are performed. Access to contaminated areas is secured to provide controlled access for inspection and maintenance.

The engineering and planning requirements are similar to those for the DECON alternative, although a shorter time period is expected for these activities due to the more limited work scope. Site preparations are also similar to those for the DECON alternative. However, with the exception of the required radiation surveys and site characterizations, the mobilization and preparation of site facilities is less extensive.

The SAFSTOR-2 cost estimate is based upon VCSNS operating for an additional 20 years. It is not expected that this additional operating time will have significant cost impacts, other than the change to the spent fuel disposal schedule and associated capital purchases for spent fuel storage cask and transfer costs, and a slight increase in the disposal cost for the reactor vessel and internals due to increased neutron activation.

2.2.1 Period 1 - Preparations

Preparations for long-term storage include the planning for permanent defueling of the reactor, revision of technical specifications appropriate to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

The process of placing the plant in safe-storage includes, but is not limited to, the following activities:

- Isolation of the spent fuel storage services and fuel handling systems so that safe-storage operations may commence on the balance of the plant. This activity may be carried out by plant personnel in accordance with existing operating technical specifications. Activities are scheduled around the fuel handling systems to the greatest extent possible.
- Transferring the spent fuel from the storage pool to the DOE or to the ISFSI, following the minimum required cooling period in the spent fuel pool.
- Draining and de-energizing of the non-contaminated systems not required to support continued site operations or maintenance.
- Disposing of contaminated filter elements and resin beds not required for processing wastes from layup activities for future operations.
- Draining of the reactor vessel, with the internals left in place and the vessel head secured.
- Draining and de-energizing non-essential, contaminated systems with decontamination as required for future maintenance and inspection.
- Preparing lighting and alarm systems whose continued use is required; de-energizing portions of fire protection, electric power, and HVAC systems whose continued use is not required.
- Cleaning of the loose surface contamination from building access pathways.
- Performing an interim radiation survey of plant, posting warning signs where appropriate.
- Erecting physical barriers and/or securing all access to radioactive or contaminated areas, except as required for inspection and maintenance.
- Installing security and surveillance monitoring equipment and relocating security fence around secured structures, as required.

2.2.2 Period 2 - Dormancy

The second phase identified by the NRC in its rule addresses licensed activities during a storage period and is applicable to the dormancy phases of the deferred decommissioning alternatives. Dormancy activities include a 24-hour security force, preventive and corrective maintenance on security systems, area lighting, general building maintenance, heating and ventilation of buildings, routine radiological inspections of contaminated structures, maintenance of structural integrity, and a site environmental and radiation monitoring program. Resident maintenance personnel perform equipment maintenance, inspection activities, routine services to maintain safe conditions, adequate lighting, heating, and ventilation, and periodic preventive maintenance on essential site services.

An environmental surveillance program is carried out during the dormancy period to ensure that releases of radioactive material to the environment are prevented or detected and controlled. Appropriate emergency procedures are established and initiated for potential releases that exceed prescribed limits. The environmental surveillance program constitutes an abbreviated version of the program in effect during normal plant operations.

Security during the dormancy period is conducted primarily to protect the spent nuclear fuel while it is on site, prevent unauthorized entry, and to protect the public from the consequences of their own actions. The security fence, sensors, alarms, and other surveillance equipment provide security. Fire and radiation alarms are also monitored and maintained. While remote surveillance is an option, it does not offer the immediate response time of a physical presence.

Consistent with the DECON scenario, the spent fuel storage pool is emptied within seven years of the cessation of operations. It is assumed that the transfer of the spent fuel from the site to the DOE begins in 2054. The transfer continues throughout the dormancy period until completed in 2095. This assumption is made for purposes of this estimate, although it is acknowledged that the plant owner will seek the most expeditious means of removing fuel from the site when DOE commences performance. If the assumption of transfer of fuel from the ISFSI to DOE is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers and to dispose of existing containers. Once emptied, the ISFSI is secured for storage and decommissioned along with the power block structures in Period 4.

After a period of storage (such that license termination is accomplished within 60 years of final shutdown), it is required that the licensee submit an application to terminate the license, along with a LTP (described in Section 2.1.2), thereby initiating the third phase.

2.2.3 Periods 3 and 4 - Delayed Decommissioning

Prior to the commencement of decommissioning operations, preparations are undertaken to reactivate site services and prepare for decommissioning. Preparations include engineering and planning, a detailed site characterization, and the assembly of a decommissioning management organization. Final planning and the assembly of activity specifications and detailed work procedures are also initiated at this time.

Much of the work in developing a termination plan is relevant to the development of the detailed engineering plans and procedures. The activities associated with this phase and the follow-on decontamination and dismantling processes are detailed in Sections 2.1.1 and 2.1.2. The primary difference between the sequences anticipated for the DECON and this deferred scenario is the absence, in the latter, of any constraint on the dismantling process due to the operation of the spent fuel pool in the DECON option.

Variations in the length of the dormancy period are expected to have some effect upon the quantities of radioactive wastes generated from system and structure removal operations. Given the levels of radioactivity and spectrum of radionuclides expected from sixty to eighty years of plant operation, no plant process system identified as being contaminated upon final shutdown will become releasable due to the decay period alone. However, due to the lower activity levels, a greater percentage of the waste volume can be designated for off-site processing and recovery.

The delay in decommissioning also yields lower working area radiation levels. As such, the estimate for this delayed scenario incorporates reduced ALARA controls for the SAFSTOR's lower occupational exposure potential.

Although the initial radiation levels due to ^{60}Co will substantially decrease during the dormancy period, the internal components of the reactor vessel will still exhibit sufficiently high radiation dose rates to require remote sectioning under water due to the presence of long-lived radionuclides such as ^{94}Nb, ^{59}Ni, and ^{63}Ni. Therefore, the dismantling procedures described for the DECON alternative would still be employed during this scenario. Portions of the biological shield will still be radioactive due to the presence of activated trace elements with long half-lives (^{152}Eu and ^{154}Eu). Decontamination will require controlled removal and disposal. It is assumed that radioactive corrosion products on inner surfaces of piping and components will not have decayed to levels that will permit unrestricted use or allow conventional removal. These systems and components will be surveyed as they are removed and disposed of in accordance with the existing radioactive release criteria.

2.2.4 Period 5 - Site Restoration

Following completion of decommissioning operations, site-restoration activities begin. Dismantling, as a continuation of the decommissioning process is a cost-effective option, as described in Section 2.1.3. The basis for the dismantling cost is consistent with that described for DECON, presuming the removal of structures and site facilities to a nominal depth of three feet below grade and the limited restoration of the site.

3. COST ESTIMATES

The cost estimates prepared for decommissioning VCSNS consider the unique features of the site, including the nuclear steam supply system, electric power generating systems, structures, and supporting facilities. The basis of the estimates, including the sources of information relied upon, the estimating methodology employed, site-specific considerations, and other pertinent assumptions, is described in this section.

3.1 BASIS OF ESTIMATES

The current estimates were developed using the site-specific, technical information relied upon in the decommissioning analysis prepared in 2012. This information was reviewed for the current analysis and updated as deemed appropriate. Review of systems and structural information confirmed that, with the exception of the new FLEX storage building, emergency response building, and combined maintenance shop, there were no substantive changes, over the four year period to the configuration of the plant or site facilities that would impact decommissioning. The site-specific considerations and assumptions used in the previous evaluation were also revisited. Modifications were incorporated where new information was available or experience from ongoing decommissioning programs provided viable alternatives or improved processes.

3.2 METHODOLOGY

The methodology used to develop the estimates follows the basic approach originally presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates,"[24] and the DOE "Decommissioning Handbook."[25] These documents present a unit factor method for estimating decommissioning activity costs, which simplifies the estimating calculations. Unit factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) are developed using local labor rates. The activity-dependent costs are estimated with the item quantities (cubic yards and tons), developed from plant drawings and inventory documents. Removal rates and material costs for the conventional disposition of components and structures rely upon information available in the industry publication, "Building Construction Cost Data," published by R.S. Means.[26]

The unit factor method provides a demonstrable basis for establishing reliable cost estimates. The detail provided in the unit factors, including activity duration, labor costs (by craft), and equipment and consumable costs, ensures that essential elements have not been omitted. Appendix A presents the detailed development of a typical unit factor. Appendix B provides the values contained within one set of factors developed for this analysis.

This analysis reflects lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells, and associated facilities, completed in 1997. In addition, the planning and engineering for the Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, San Onofre and Vermont Yankee nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Work Difficulty Factors

TLG has historically applied work difficulty adjustment factors (WDFs) to account for the inefficiencies in working in a power plant environment. WDFs are assigned to each unique set of unit factors, commensurate with the inefficiencies associated with working in confined, hazardous environments. The ranges used for the WDFs are as follows:

- Access Factor 10% to 20%
- Respiratory Protection Factor 10% to 50%
- Radiation/ALARA Factor 10% to 37%
- Protective Clothing Factor 10% to 30%
- Work Break Factor 8.33%

The factors and their associated range of values were developed in conjunction with the AIF/NESP-036 study. The application of the factors is discussed in more detail in that publication.

Scheduling Program Durations

The unit factors, adjusted by the WDFs as described above, are applied against the inventory of materials to be removed in the radiological controlled areas. The resulting labor-hours, or crew-hours, are used in the development of the decommissioning program schedule, using resource loading and event sequencing considerations. The scheduling of conventional removal and dismantling activities is based upon productivity information available from the "Building Construction Cost Data" publication. In the DECON alternative, dismantling of the fuel handing building systems and decontamination of the spent fuel pool is also dependent upon the timetable for the transfer of the spent fuel assemblies from the pool to the ISFSI.

An activity duration critical path is used to determine the total decommissioning program schedule. The schedule is relied upon in calculating the carrying costs, which include program management, administration, field engineering, equipment rental, and support services such as quality control and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

3.3 FINANCIAL COMPONENTS OF THE COST MODEL

TLG's proprietary decommissioning cost model, DECCER, produces a number of distinct cost elements. These direct expenditures, however, do not comprise the total cost to accomplish the project goal, i.e., license termination, spent fuel management and site restoration.

3.3.1 Contingency

Inherent in any cost estimate that does not rely on historical data is the inability to specify the precise source of costs imposed by factors such as tool breakage, accidents, illnesses, weather delays, and labor stoppages. In the DECCER cost model, contingency fulfills this role. Contingency is added to each line item to account for costs that are difficult or impossible to develop analytically. Such costs are historically inevitable over the duration of a job of this magnitude; therefore, this cost analysis includes funds to cover these types of expenses.

The activity- and period-dependent costs are combined to develop the total decommissioning cost. A contingency is then applied on a line-item basis, using one or more of the contingency types listed in the AIF/NESP-036 study. "Contingencies" are defined in the American Association of Cost Engineers "Project and Cost Engineers' Handbook"[27] as "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The cost elements in this analysis are based upon ideal conditions and maximum efficiency; therefore, consistent with industry practice, contingency is included. In the AIF/NESP-036 study, the types of unforeseeable events that are likely to occur in decommissioning are discussed and guidelines are provided for a contingency percentage in each category. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

The use and role of contingency within decommissioning estimates is not a "safety factor issue." Safety factors provide additional security and address situations that may never occur. Contingency funds are expected to be fully expended throughout the program. They also provide assurance that sufficient funding is available to accomplish the intended tasks. An estimate without contingency, or from which contingency has been removed, can disrupt the orderly progression of events and jeopardize a successful conclusion to the decommissioning process.

For example, the most technologically challenging task in decommissioning a commercial nuclear plant is the disposition of the reactor vessel and internal components, now highly radioactive after a lifetime of exposure to core activity. The disposition of these components forms the basis of the critical path (schedule) for decommissioning operations. Cost and schedule are interdependent, and any deviation in schedule has a significant impact on cost for performing a specific activity.

Disposition of the reactor vessel internals involves the underwater cutting of complex components that are highly radioactive. Costs are based upon optimum segmentation, handling, and packaging scenarios. The schedule is primarily dependent upon the turnaround time for the heavily shielded shipping casks, including preparation, loading, and decontamination of the containers for transport. The number of casks required is a function of the pieces generated in the segmentation activity, a value calculated on optimum performance of the tooling employed in cutting the various subassemblies. The expected optimization, however, may not be achieved, resulting in delays and additional program costs. For this reason, contingency must be included to mitigate the consequences of the expected inefficiencies inherent in this complex activity, along with related concerns associated with the operation of highly specialized tooling, field conditions, and water clarity.

Contingency funds are an integral part of the total cost to complete the decommissioning process. Exclusion of this component puts at risk a successful completion of the intended tasks and, potentially, subsequent related activities. For this study, TLG examined the major activity-related problems (decontamination, segmentation, equipment handling, packaging, transport, and waste disposal) that necessitate a contingency. Individual activity contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from TLG's actual decommissioning experience. The contingency values used in this study are as follows:

- Decontamination 50%
- Contaminated Component Removal 25%
- Contaminated Component Packaging 10%
- Contaminated Component Transport 15%
- Low-Level Radioactive Waste Disposal 25%

- Reactor Segmentation 75%
- NSSS Component Removal 25%
- Reactor Waste Packaging 25%
- Reactor Waste Transport 25%
- Reactor Vessel Component Disposal 50%

- GTCC Disposal 15%
- Non-Radioactive Component Removal 15%
- Heavy Equipment and Tooling 15%
- Supplies 25%
- Engineering 15%

- Energy 15%
- Characterization and Termination Surveys 30%
- Construction 15%
- Taxes and Fees 10%
- Insurance 10%

- Staffing 15%
- Spent Fuel Storage (Dry) Systems 15%
- Spent Fuel Transfer Costs 15%
- Operations and Maintenance Expenses 15%
- ISFSI Decommissioning 25%

The contingency values are applied to the appropriate components of the estimates on a line item basis. A composite value is then reported at the end of each detailed estimate (as provided in Appendix C through E).

Appendix F, the ISFSI decommissioning calculation, uses a flat 25% contingency added at the end of the calculation.

3.3.2 Financial Risk

In addition to the routine uncertainties addressed by contingency, another cost element that is sometimes necessary to consider when bounding decommissioning costs relates to uncertainty, or risk. Examples can include changes in work scope, pricing, job performance, and other variations that could conceivably, but not necessarily, occur. Consideration is sometimes necessary to generate a level of confidence in the estimate, within a range of probabilities. TLG considers these types of costs under the broad term “financial risk.” Included within the category of financial risk are:

- Transition activities and costs: ancillary expenses associated with reducing the size of the labor force 50% to 80% shortly after the cessation of plant operations, national or company-mandated retraining, and retention incentives for key personnel.
- Delays in approval of the decommissioning plan due to intervention, public participation in local community meetings, legal challenges, and national and local hearings.
- Changes in the project work scope from the baseline estimate, involving the discovery of unexpected levels of contaminants, contamination in places not previously expected, contaminated soil previously undiscovered (either radioactive or hazardous material contamination), variations in plant inventory or configuration not indicated by the as-built drawings.
- Regulatory changes, for example, affecting worker health and safety, site release criteria, waste transportation, and disposal.
- Policy decisions altering national commitments (e.g., in the ability to accommodate certain waste forms for disposition, or in the timetable for such, or the start and rate of acceptance of spent fuel by the DOE).
- Pricing changes for basic inputs such as labor, energy, materials, and disposal. Items subject to widespread price competition (such as materials) may not show significant variation; however, others such as energy could exhibit large pricing uncertainties.

This cost study does not add any additional costs to the estimate for financial risk, since there is insufficient historical data from which to project future liabilities. Consequently, the areas of uncertainty or risk are revisited periodically and addressed through repeated revisions or updates of the base estimates.

3.4 SITE-SPECIFIC CONSIDERATIONS

There are a number of site-specific considerations that affect the method for dismantling and removal of equipment from the site and the degree of restoration required. The cost impact of the considerations identified below is included in this cost study.

3.4.1 Spent Fuel Management

The cost to dispose the spent fuel generated from plant operations is not reflected within the estimates to decommission VCSNS. Ultimate disposition of the spent fuel is within the province of the DOE's Waste Management System, as defined by the Nuclear Waste Policy Act. As such, the disposal cost is financed by a surcharge paid into the DOE's waste fund during operations. On November 19, 2013, the U.S. Court of Appeals for the D.C. Circuit ordered the Secretary of the Department of Energy to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators until the DOE has conducted a legally adequate fee assessment.

The NRC does, however, requires licensees to establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title of the fuel is transferred to the Secretary of Energy. This requirement is prepared for through inclusion of certain high-level waste cost elements within the estimates, as described below.

Completion of the decommissioning process is highly dependent upon the DOE's ability to remove spent fuel from the site. The spent fuel management plan for VCSNS assumes "just-in-time" acceptance, i.e., the DOE will be able to complete the transfer of spent fuel so as not to impede the SAFSTOR-1 deferred decommissioning scenario and the termination of the operating license within the required 60-year period (from the cessation of operations). To achieve this objective, based upon the oldest fuel receiving the highest priority and an annual maximum rate of transfer of 3,000 metric tons of uranium, DOE would commence pickup of spent fuel from VCSNS in 2054 so that the fuel is completely removed from the site by 2095 (one year prior to the latest assumed start date for the decommissioning). These dates are also used for the DECON scenario. The SAFSTOR-2 deferred decommissioning scenario uses the same logic as SAFSTOR-1 (DOE first pickup of VCSNS fuel in 2054), but with the additional 20 years of operations, estimates a final pickup date of 2119.

ISFSI

Due to DOE's inability to remove fuel from the site, an ISFSI has been constructed at the site and fuel casks have been emplaced thereon to support continued plant operations.

An ISFSI has been constructed to support continued plant operations. The ISFSI will continue to operate throughout decommissioning, and beyond the conclusion of the remediation phase in the DECON decommissioning scenario, until such time that the transfer of spent fuel to the DOE can be completed. The scenario is similar for the SAFSTOR alternative; however, based upon the expected completion date for fuel transfer, the ISFSI will be emptied prior to the commencement of deferred decommissioning operations.

Operation and maintenance costs for the spent fuel pool and the ISFSI are included within the estimates and address the cost for staffing the facility, as well as security, insurance, and licensing fees. The estimates include the costs to purchase, load, and transfer the multi-purpose spent fuel storage canisters (MPCs) from the pool to the ISFSI. Costs are also provided for transfer of the MPCs to the DOE from the ISFSI (although it is acknowledged that this may not occur and that the fuel in the MPCs may have to be repackaged at DOE expense).

Storage Canister Design

The dry storage system at VCSNS is based upon Holtec International's (Holtec) HI-STORM FW System. The HI-STORM FW System consists of a sealed metallic multi-purpose canister (MPC) contained within an overpack constructed from a combination of steel and concrete. The MPC can accommodate up to 37 undamaged Zircaloy-clad pressurized water fuel assemblies. The overpack provides structural protection, cooling, and radiological shielding for the MPC.

Canister Loading and Transfer

The estimates include the cost for the labor and equipment to transfer and load each spent fuel canister into the DOE transport cask or to the ISFSI from the wet storage pool. For estimating purposes, an allowance is used to estimate the cost to transfer the fuel from the ISFSI into the DOE transport cask.

Operations and Maintenance

The estimates also include the cost of operating and maintaining the spent fuel pool and the ISFSI, respectively. Pool operations are expected to continue approximately seven years after the cessation of operations. It is assumed that the seven years provides the necessary cooling period for the final core to meet the licensing and design requirements of the dry cask storage vendor's system. ISFSI operating costs are based upon the previously stated assumptions on fuel transfer assumptions. ISFSI operating costs are based upon a 53-year period of operations following plant shutdown.

ISFSI Decommissioning

In accordance with 10 CFR §72.30, licensees must have a proposed decommissioning plan for the ISFSI site and facilities that includes a cost estimate for the plan. The plan should contain sufficient information on the proposed practices and procedures for the decontamination of the ISFSI and for the disposal of residual radioactive materials after all spent fuel, high-level radioactive waste, and reactor-related GTCC waste have been removed.

The dry storage vendor does not expect the concrete casks to have any interior or exterior radioactive surface contamination. Any neutron activation of the steel and concrete is expected to be extremely small.

The decommissioning estimate is based on the premise that some of the concrete casks will contain low levels of neutron-induced residual radioactivity that would necessitate remediation at the time of decommissioning. As an allowance, 5 casks are assumed to be affected, i.e., contain residual radioactivity. The allowance is based upon the number of casks required for the final core off-load (i.e., 157 offloaded assemblies, 37 assemblies per cask) which results in 5 overpacks. It is assumed that these are the final casks offloaded; consequently they have the least time for radioactive decay of the neutron activation products.

No contamination or activation of the ISFSI pad is assumed. It would be expected that this assumption would be confirmed as a result of good radiological practice of surveying potentially impacted areas after each spent fuel transfer campaign. As such, only verification surveys are included for the pad in the decommissioning estimate. The estimate is limited to costs necessary to terminate the ISFSI's NRC license and meet the §20.1402 criteria for unrestricted use.

In accordance with the specific requirements of 10 CFR §72.30 for the ISFSI work scope, the cost estimate for decommissioning the ISFSI reflects: 1) the cost of an independent contractor performing the decommissioning activities; 2) an adequate contingency factor; and 3) the cost of meeting the criteria for unrestricted use. The cost summary for decommissioning the ISFSI is presented in Appendix F.

<u>GTCC</u>

The dismantling of the reactor internals is expected to generate radioactive waste considered unsuitable for shallow land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. [28]

Although the material is not classified as high-level waste, federal regulations under the Act designate that disposal of this material is a federal responsibility under Section 3(b)(1)(D). However, the DOE has not been forthcoming with an acceptance criteria or disposition schedule for this material, and numerous questions remain as to the ultimate disposal cost and waste form requirements.

For purposes of this estimate, the GTCC has been assumed to be packaged in the same canisters used to store spent fuel and disposed of as high-level waste, at a cost equivalent to that envisioned for the spent fuel. The number of canisters required and the packaged volume for GTCC was based upon experience at Maine Yankee (e.g., the constraints on loading as identified in the canister's certificate of compliance).

It is assumed that the DOE would not accept this waste prior to completing the transfer of spent fuel. Therefore, until such time as the

DOE is ready to accept GTCC waste, it is assumed that this material would remain in storage at the VCSNS site (for the DECON alternative). In the SAFSTOR scenario, the GTCC material is shipped directly to a DOE facility as it is generated since the fuel has been removed from the site prior to the start of decommissioning.

3.4.2 Reactor Vessel and Internal Components

The reactor pressure vessel and internal components are segmented for disposal in shielded, reusable transportation casks. Segmentation is performed in the refueling canal, where a turntable and remote cutter are installed. The vessel is segmented in place, using a mast-mounted cutter supported off the lower head and directed from a shielded work platform installed overhead in the reactor cavity. Transportation cask specifications and transportation regulations dictate the segmentation and packaging methodology.

Intact disposal of reactor vessel shells has been successfully demonstrated at several of the sites that have been decommissioned. Access to navigable waterways has allowed these large packages to be transported to the Barnwell disposal site with minimal overland travel. Intact disposal of the reactor vessel and internal components can provide savings in cost and worker exposure by eliminating the complex segmentation requirements, isolation of the GTCC material, and transport/storage of the resulting waste packages. Portland General Electric (PGE) was able to dispose of the Trojan reactor as an intact package (including the internals). However, its location on the Columbia River simplified the transportation analysis since:

- the reactor package could be secured to the transport vehicle for the entire journey, i.e., the package was not lifted during transport,
- there were no man-made or natural terrain features between the plant site and the disposal location that could produce a large drop, and
- transport speeds were very low, limited by the overland transport vehicle and the river barge.

As a member of the Northwest Compact, PGE had a site available for disposal of the package - the US Ecology facility in Washington State. The characteristics of this arid site proved favorable in demonstrating compliance with land disposal regulations.

It is not known whether this option will be available when the VCSNS plant ceases operation. Future viability of this option will depend upon the ultimate location of the disposal site, as well as the disposal site licensee's ability to accept highly radioactive packages and effectively isolate them from the environment. Consequently, the study assumes that the reactor vessel will require segmentation, as a bounding condition.

3.4.3 Primary System Components

In the DECON scenario, the reactor coolant system components are assumed to be decontaminated using chemical agents prior to the start of dismantling operations. This type of decontamination can be expected to have a significant ALARA impact, since in this scenario the removal work is done within the first few years of shutdown. A decontamination factor (average reduction) of 10 is assumed for the process. Disposal of the decontamination solution effluent is included within the estimate as a "process liquid waste" charge. In the SAFSTOR scenario, radionuclide decay is expected to provide the same benefit and, therefore, a chemical decontamination is not included.

The following discussion deals with the removal and disposition of the steam generators, but the techniques involved are also applicable to other large components, such as heat exchangers, component coolers, and the pressurizer. The steam generators' size and weight, as well as their location within the reactor building, will ultimately determine the removal strategy.

A trolley crane is set up for the removal of the generators. It can also be used to move portions of the steam generator cubicle walls and floor slabs from the reactor building to a location where they can be decontaminated and transported to the material handling area. Interferences within the work area, such as grating, piping, and other components are removed to create sufficient laydown space for processing these large components.

The generators are rigged for removal, disconnected from the surrounding piping and supports, and maneuvered into the open area where they are lowered onto a dolly. Each generator is rotated into the horizontal position for extraction from the containment and placed onto a multi-wheeled vehicle for transport to an on-site processing and storage area.

Disposal costs are based upon the displaced volume and weight of the units. Each component is then loaded onto a rail car for transport to the disposal facility.

Reactor coolant piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzle zone. The piping is boxed and transported by shielded van. The reactor coolant pumps and motors are lifted out intact, packaged, and transported for processing and/or disposal.

3.4.4 Main Turbine and Condenser

The main turbine is dismantled using conventional maintenance procedures. The turbine rotors and shafts are removed to a laydown area. The lower turbine casings are removed from their anchors by controlled demolition. The main condensers are also disassembled and moved to a laydown area. Material is then prepared for transportation to an off-site recycling facility where it is surveyed and designated for either decontamination or volume reduction, conventional disposal, or controlled disposal. Components are packaged and readied for transport in accordance with the intended disposition.

3.4.5 Retired Components

The estimates include the disposition of three retired steam generators currently in storage at the site.

3.4.6 Transportation Methods

Contaminated piping, components, and structural material other than the highly activated reactor vessel and internal components will qualify as LSA-I, II or III or Surface Contaminated Object, SCO-I or II, as described in Title 49.[29] The contaminated material will be packaged in Industrial Packages (IP-1, IP-2, or IP-3, as defined in 49 CFR §173.411) for transport unless demonstrated to qualify as their own shipping containers. The reactor vessel and internal components are expected to be transported in accordance with 10 CFR Part 71, in Type B containers. It is conceivable that the reactor, due to its limited specific activity, could qualify as LSA II or III. However, the high radiation levels on the outer surface would require that additional shielding be incorporated within the packaging so as to attenuate the dose to levels acceptable for transport.

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major reactor components to be shipped under current transportation regulations and disposal requirements.

Transport of the highly activated metal, produced in the segmentation of the reactor vessel and internal components, will be by shielded truck cask. Cask shipments may exceed 95,000 pounds, including vessel segment(s), supplementary shielding, cask tie-downs, and tractor-trailer. The maximum level of activity per shipment assumed permissible was based upon the license limits of the available shielded transport casks. The segmentation scheme for the vessel and internal segments is designed to meet these limits.

The transport of large intact components (e.g., large heat exchangers and other oversized components) will be by a combination of truck, rail, and/or multi-wheeled transporter to the Barnwell disposal facility.

Transportation costs for Class A radioactive material requiring controlled disposal are based upon the mileage to Barnwell, South Carolina. Transportation costs for the higher activity Class B and C radioactive material are also based upon the mileage to Barnwell, South Carolina. Transportation costs for off-site waste processing are based upon the mileage to Oak Ridge, Tennessee. Truck transport costs were developed from published tariffs from Tri-State Motor Transit.[30] The transportation cost for the GTCC material is assumed to be contained within the disposal cost.

3.4.7 Low-Level Radioactive Waste Disposal

To the greatest extent practical, metallic material generated in the decontamination and dismantling processes is processed to reduce the total cost of controlled disposal. Material meeting the regulatory and/or site release criterion, is released as scrap, requiring no further cost consideration. Conditioning (preparing the material to meet the waste acceptance criteria of the disposal site) and recovery of the waste stream is performed off site at a licensed processing center. Any material leaving the site is subject to a survey and release charge, at a minimum.

The mass of radioactive waste generated during the various decommissioning activities at the site is shown on a line-item basis in the detailed Appendices C through F, and summarized in Section 5. The quantified waste summaries shown in these tables are consistent with 10 CFR Part 61 classifications. Commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations. The volumes are calculated based on the exterior package dimensions for containerized material or a specific calculation for components serving as their own waste containers.

The more highly activated reactor components will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Class A waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

Disposal fees are calculated using the current disposal agreement for the Atlantic Compact, with surcharges added for the highly activated components, for example, generated in the segmentation of the reactor vessel internals. Low-level radioactive material, or material suspected to be contaminated, is sent to a waste processor for conditioning and treatment, including volume reduction and disposal.

Material exceeding Class C limits (limited to material closest to the reactor core and comprising less than 1% of the total waste volume) is generally not suitable for shallow-land disposal. This material is packaged in the same multipurpose canisters used for spent fuel storage/transport.

3.4.8 Site Conditions Following Decommissioning

The NRC will amend or terminate the site license if it determines that site remediation has been performed in accordance with the license termination plan, and that the terminal radiation survey and associated documentation demonstrate that the facility is suitable for release. The NRC's involvement in the decommissioning process will end at this point. Building codes and environmental regulations will dictate the next step in the decommissioning process, as well as owners' own future plans for the site.

A significant amount of the below grade piping is located around the perimeter of the power block. The estimate includes a cost to excavate this area to an average depth of four feet so as to expose the piping, duct bank, conduit, and any near-surface grounding grid. The overburden is surveyed and stockpiled on site for future use in backfilling the below grade voids.

Only existing site structures are considered in the dismantling cost. Site structures are removed to a nominal depth of three feet below grade. The voids are backfilled with clean debris and capped with soil. The site is then re-graded to conform to the adjacent landscape. Vegetation is established to inhibit erosion. These "non-radiological costs" are included in the total cost of decommissioning.

Concrete rubble generated from demolition activities is processed and made available as clean fill for the power block foundations. Excess construction debris is trucked off site as an alternative to onsite disposal. The excavations will be regraded such that the power block area will have a final contour consistent with adjacent surroundings.

The Nuclear Learning Center and Nuclear Operations Building will be left in place. The electrical switchyard will also remain after VCSNS is decommissioned in support of the regional transmission and distribution system.

The estimates do not assume the remediation of any significant volume of contaminated soil. This assumption may be affected by continued plant operations and/or future regulatory actions, such as the development of site-specific release criteria.

3.5 ASSUMPTIONS

The following are the major assumptions made in the development of the estimates for decommissioning the site.

3.5.1 <u>Estimating Basis</u>

Decommissioning costs are reported in the year of projected expenditure; however, the values are provided in 2016 dollars. Costs provided as input to the decommissioning cost model in dollars other than 2016 dollars were escalated to 2016 dollars.

The plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, were reviewed for this analysis. The following structures were added to the 2012 inventory: FLEX storage building, emergency response building, and combined maintenance shop.

The study follows the principles of ALARA through the use of work duration adjustment factors. These factors address the impact of activities such as radiological protection instruction, mock-up training, and the use of respiratory protection and protective clothing. The factors lengthen a task's duration, increasing costs and lengthening the overall schedule. ALARA planning is considered in the costs for engineering and planning, and in the development of activity specifications and detailed procedures. Changes to worker exposure limits may impact the decommissioning cost and project schedule.

3.5.2 Labor Costs

For purposes of this analysis, it is assumed that SCE&G will hire a Decommissioning Operations Contractor (DOC) to manage the decommissioning. SCE&G will provide site security, radiological health and safety, quality assurance and overall site administration during the decommissioning and demolition phases. Contract personnel will provide engineering services (e.g., for preparing the activity specifications, work procedures, neutron activation, and structural analyses) under the direction of SCE&G.

Personnel costs are based upon average salary information provided by SCE&G. Overhead costs are included for site and corporate support, reduced commensurate with the staffing of the project.

Reduction in the operating organization is assumed to be handled through normal staffing processes (e.g., reassignment and outplacement).

The craft labor required to decontaminate and dismantle the nuclear plant is acquired through standard site contracting practices. The current cost of labor at the site is used as an estimating basis. Craft labor costs include applicable overheads and profit.

Staffing levels are assigned by sub-period and functional area. The types of positions and staffing levels are adjusted based upon the type of activity occurring in each sub-period.

A profile of the staffing level for decommissioning, including contractors and craft, is provided in Figures 3.1, 3.2, and 3.3 for the DECON, SAFSTOR-1 and SAFSTOR-2 scenarios, respectively. Utility staffing levels will gradually decrease after completing the removal of physical systems. Staffing levels and management support will vary based upon the amount and type of decommissioning work. Craft manpower levels decrease after systems removal and structures decontamination and drop substantially during the delay period and the license termination survey period. However, craft levels increase again during the site restoration period due to the work associated with structures demolition.

Security, while reduced from operating levels, is maintained throughout the decommissioning for access control, material control, and to safeguard the spent fuel (in accordance with the requirements of 10 CFR Part 37, Part 72, and Part 73). Security costs include provisions for recurring expenses. Once the fuel has been transferred to the DOE in 2096 (or 2119 for SAFSTOR-2), the security organization will be reduced to Part 37 requirements.

3.5.3 Design Conditions

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major NSSS components to be shipped under current transportation regulations and disposal requirements.

The curie contents of the vessel and internals at final shutdown are derived from those listed in NUREG/CR-3474.[31] Actual estimates are derived from the curie/gram values contained therein and adjusted for the different mass of the VCSNS components, projected operating life, and different periods of decay. Additional short-lived isotopes were derived from NUREG/CR-0130[32] and NUREG/CR-0672,[33] and benchmarked to the long-lived values from NUREG/CR-3474.

It is anticipated that there will be control element assemblies (CEAs) in the spent fuel pool at the cessation of operations, including those CEAs from the final core. This analysis assumes that the CEAs can be disposed of along with the spent fuel at no additional cost (in accordance with Appendix E of the Standard Contract).

It is anticipated that there may other highly activated material, generated during plant operations, in the spent fuel pool at the cessation of operations. This analysis assumes that the cost of disposal will be paid for by operations' accruals and not charged to the decommissioning program.

Neutron activation of the containment building structure is assumed to be confined to the biological shield.

3.5.4 General

Transition Activities

Existing warehouses are cleared of non-essential material and remain for use by SCE&G and its subcontractors. The warehouses are removed once they are no longer needed. The plant's operating staff performs the following activities at no additional cost or credit to the project during the transition period:

- Drain and collect fuel oils, lubricating oils, and transformer oils for recycle and/or sale.
- Drain and collect acids, caustics, and other chemical stores for recycle and/or sale.
- Process operating waste inventories. Disposal of operating wastes (e.g., filtration media, resins) during this initial period is not considered a decommissioning expense.

Scrap and Salvage

The existing plant equipment is considered obsolete and suitable for scrap as deadweight quantities only. SCE&G will make economically reasonable efforts to salvage equipment following final plant shutdown. However, dismantling techniques assumed by TLG for equipment in this analysis are not consistent with removal techniques required for salvage (resale) of equipment. Experience has indicated that some buyers wanted equipment stripped down to very specific requirements before they would consider purchase. This required expensive rework after the equipment had been removed from its installed location. Since placing a salvage value on this machinery and equipment would be speculative, and the value would be small in comparison to the overall decommissioning expenses, this analysis does not attempt to quantify the value that an owner may realize based upon those efforts.

It is assumed, for purposes of this analysis, that any value received from the sale of scrap generated in the dismantling process would be more than offset by the on-site processing costs. The dismantling techniques assumed in the decommissioning estimates do not include the additional cost for size reduction and preparation to meet "furnace ready" conditions. For example, the recovery of copper from electrical cabling may require the removal and disposition of any contaminated insulation, an added expense. With a volatile market, the potential profit margin in scrap recovery is highly speculative, regardless of the ability to free release this material. This assumption is an implicit recognition of scrap value in the disposal of clean metallic waste at no additional cost to the project.

Furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, and other property is removed at no cost or credit to the decommissioning project. Disposition may include relocation to other facilities. Spare parts are also made available for alternative use.

The concrete debris resulting from building demolition activities is crushed on site to reduce the size of the debris. The resulting crushed concrete is used to backfill below grade voids. The rebar removed from the concrete crushing process is disposed of as scrap steel in a similar fashion as other scrap metal as discussed previously.

<u>Energy</u>

For estimating purposes, the plant is assumed to be de-energized, with the exception of those facilities associated with spent fuel storage. Replacement power costs are used to calculate the cost of energy consumed during decommissioning for tooling, lighting, ventilation, and essential services.

<u>Emergency Planning</u>

FEMA fees associated with emergency planning are assumed to continue for approximately 18 months following the cessation of operations. At this time, the fees are discontinued. The timing is based upon the anticipated condition of the spent fuel (i.e., the hottest spent fuel assemblies are assumed to be cool enough that no substantial Zircaloy oxidation and off-site event would occur with the loss of spent fuel pool water). State fees are included until all fuel has been moved from the pool into dry storage (approximately seven years following the cessation of operations). Local fees are included until the fuel is removed from the site.

Insurance

Costs for continuing coverage (nuclear liability and property insurance) following cessation of plant operations and during decommissioning are included and based upon current operating premiums. Reductions in premiums, throughout the decommissioning process, are based upon the guidance and the limits for coverage defined in the NRC's proposed rulemaking "Financial Protection Requirements for Permanently Shutdown Nuclear Power Reactors."[34] The NRC's financial protection requirements are based on various reactor (and spent fuel) configurations.

Taxes

Property taxes are included for the full year in the shutdown year. After the first year, based on present state tax codes, there will be no net utility property to serve as a tax basis, as the plant will be retired.

Disposal of Processed Water

This estimate assumes that processed water which meets state and federal release limits can be disposed of without additional cost.

Site Modifications

The perimeter fence and in-plant security barriers will be moved, as appropriate, to conform to the Site Security Plan in force during the various stages of the project.

3.6 COST ESTIMATE SUMMARY

Schedules of expenditures are provided in Tables 3.1, 3.2 and 3.3. The tables delineate the cost contributors by year of expenditures as well as cost contributor (e.g., labor, materials, and waste disposal).

The tables in Appendices C through F provide additional detail. The cost elements in these tables are assigned to one of three subcategories: "License Termination," "Spent Fuel Management," and "Site Restoration." The subcategory "License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). The cost reported for this subcategory is generally sufficient to terminate the plant's operating license, recognizing that there may be some additional cost impact from spent fuel management. The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). The basis for the ISFSI decommissioning cost that is included in both Appendices C, D and E is provided in Appendix F.

The "Spent Fuel Management" subcategory contains costs associated with the containerization and transfer of spent fuel from the wet storage pool to the ISFSI for interim storage and/or to the DOE directly from the pool (SAFSTOR-2 only), as well as the transfer of the spent fuel in storage at the ISFSI to the DOE. Costs are also included for the operations of the pool and management of the ISFSI until such time that the transfer of all fuel from this facility to an off-site location (e.g., interim storage facility) is complete.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are removed to a depth of three feet and backfilled.

As discussed in Section 3.4.1, it is assumed that the DOE will not accept the GTCC waste prior to completing the transfer of spent fuel. Therefore, the cost of GTCC disposal is included in the final year of ISFSI operation (for the DECON alternative) or during the reactor vessel dismantling operations period (SAFSTOR alternatives). While designated for disposal at a federal facility along with the spent fuel, GTCC waste is still classified as low-level radioactive waste and, as such, included as a "License Termination" expense.

Decommissioning costs are reported in 2016 dollars. Costs are not inflated, escalated, or discounted over the period of expenditure (or projected lifetime of the plant). The schedules are based upon the detailed activity costs reported in Appendices C through F.

TABLE 3.1
DECON ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042	24,383	852	875	13	10,810	36,933
2043	66,306	8,788	3,033	1,758	31,174	111,060
2044	64,640	40,242	2,267	24,587	13,713	145,448
2045	58,977	29,127	1,822	16,846	9,655	116,427
2046	55,082	17,354	1,618	8,161	8,274	90,489
2047	42,867	13,999	1,618	4,862	6,946	70,293
2048	25,027	9,105	1,623	25	5,014	40,793
2049	29,367	9,530	1,312	3,211	5,332	48,752
2050	35,616	6,077	648	3,964	4,311	50,617
2051	23,965	10,580	269	6	2,186	37,006
2052	20,279	13,444	216	0	1,992	35,931
2053	8,032	4,251	53	0	1,598	13,935
2054	4,043	1,254	0	0	1,471	6,768
2055	4,043	1,254	0	0	1,471	6,768
2056	4,054	1,257	0	0	1,475	6,787
2057	4,043	1,254	0	0	1,471	6,768
2058	4,043	1,254	0	0	1,471	6,768
2059	4,043	1,254	0	0	1,471	6,768
2060	4,054	1,257	0	0	1,475	6,787
2061	4,043	1,254	0	0	1,471	6,768
2062	4,043	1,254	0	0	1,471	6,768
2063	4,043	1,254	0	0	1,471	6,768
2064	4,054	1,257	0	0	1,475	6,787
2065	4,043	1,254	0	0	1,471	6,768
2066	4,043	1,254	0	0	1,471	6,768
2067	4,043	1,254	0	0	1,471	6,768
2068	4,054	1,257	0	0	1,475	6,787
2069	4,043	1,254	0	0	1,471	6,768
2070	4,043	1,254	0	0	1,471	6,768
2071	4,043	1,254	0	0	1,471	6,768
2072	4,054	1,257	0	0	1,475	6,787
2073	4,043	1,254	0	0	1,471	6,768

TABLE 3.1 (continued)
DECON ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2074	4,043	1,254	0	0	1,471	6,768
2075	4,043	1,254	0	0	1,471	6,768
2076	4,054	1,257	0	0	1,475	6,787
2077	4,043	1,254	0	0	1,471	6,768
2078	4,043	1,254	0	0	1,471	6,768
2079	4,043	1,254	0	0	1,471	6,768
2080	4,054	1,257	0	0	1,475	6,787
2081	4,043	1,254	0	0	1,471	6,768
2082	4,043	1,254	0	0	1,471	6,768
2083	4,043	1,254	0	0	1,471	6,768
2084	4,054	1,257	0	0	1,475	6,787
2085	4,043	1,254	0	0	1,471	6,768
2086	4,043	1,254	0	0	1,471	6,768
2087	4,043	1,254	0	0	1,471	6,768
2088	4,054	1,257	0	0	1,475	6,787
2089	4,043	1,254	0	0	1,471	6,768
2090	4,043	1,254	0	0	1,471	6,768
2091	4,043	1,254	0	0	1,471	6,768
2092	4,054	1,257	0	0	1,475	6,787
2093	4,043	1,254	0	0	1,471	6,768
2094	4,043	1,254	0	0	1,471	6,768
2095	4,027	3,706	0	0	14,856	22,588
2096	3,261	1,819	114	2,620	3,000	10,813
Total	627,694	220,323	15,468	66,051	179,228	1,108,765

TABLE 3.1a
DECON ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042	24,100	852	875	13	9,940	35,779
2043	64,873	8,097	3,033	1,758	29,028	106,789
2044	60,009	31,686	2,267	24,587	12,160	130,708
2045	53,993	19,887	1,822	16,846	8,168	100,716
2046	49,965	8,106	1,618	8,161	6,787	74,638
2047	34,174	4,951	1,618	4,862	5,459	51,065
2048	11,051	327	1,623	25	3,523	16,547
2049	20,606	2,901	1,312	3,211	4,341	32,371
2050	35,029	4,315	648	3,964	4,049	48,005
2051	8,819	479	106	6	625	10,035
2052	121	0	0	0	0	121
2053	30	0	0	0	0	30
2054-94	0	0	0	0	0	0
2095	0	2,500	0	0	13,384	15,884
2096	708	128	78	2,620	2,917	6,450
Total	363,478	84,228	15,000	66,051	100,381	629,138

TABLE 3.1b
DECON ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042	0	0	0	0	870	870
2043	230	691	0	0	2,146	3,068
2044	2,822	8,465	0	0	1,553	12,839
2045	3,047	9,141	0	0	1,487	13,675
2046	3,050	9,149	0	0	1,487	13,685
2047	7,464	8,989	0	0	1,487	17,940
2048	13,976	8,778	0	0	1,491	24,245
2049	8,761	6,630	0	0	990	16,382
2050	587	1,762	0	0	262	2,612
2051	3,534	2,387	0	0	973	6,894
2052	4,703	3,177	0	0	1,209	9,089
2053	4,202	1,726	0	0	1,406	7,334
2054	4,043	1,254	0	0	1,471	6,768
2055	4,043	1,254	0	0	1,471	6,768
2056	4,054	1,257	0	0	1,475	6,787
2057	4,043	1,254	0	0	1,471	6,768
2058	4,043	1,254	0	0	1,471	6,768
2059	4,043	1,254	0	0	1,471	6,768
2060	4,054	1,257	0	0	1,475	6,787
2061	4,043	1,254	0	0	1,471	6,768
2062	4,043	1,254	0	0	1,471	6,768
2063	4,043	1,254	0	0	1,471	6,768
2064	4,054	1,257	0	0	1,475	6,787
2065	4,043	1,254	0	0	1,471	6,768
2066	4,043	1,254	0	0	1,471	6,768
2067	4,043	1,254	0	0	1,471	6,768
2068	4,054	1,257	0	0	1,475	6,787
2069	4,043	1,254	0	0	1,471	6,768
2070	4,043	1,254	0	0	1,471	6,768
2071	4,043	1,254	0	0	1,471	6,768
2072	4,054	1,257	0	0	1,475	6,787
2073	4,043	1,254	0	0	1,471	6,768

TABLE 3.1b (continued)
DECON ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2074	4,043	1,254	0	0	1,471	6,768
2075	4,043	1,254	0	0	1,471	6,768
2076	4,054	1,257	0	0	1,475	6,787
2077	4,043	1,254	0	0	1,471	6,768
2078	4,043	1,254	0	0	1,471	6,768
2079	4,043	1,254	0	0	1,471	6,768
2080	4,054	1,257	0	0	1,475	6,787
2081	4,043	1,254	0	0	1,471	6,768
2082	4,043	1,254	0	0	1,471	6,768
2083	4,043	1,254	0	0	1,471	6,768
2084	4,054	1,257	0	0	1,475	6,787
2085	4,043	1,254	0	0	1,471	6,768
2086	4,043	1,254	0	0	1,471	6,768
2087	4,043	1,254	0	0	1,471	6,768
2088	4,054	1,257	0	0	1,475	6,787
2089	4,043	1,254	0	0	1,471	6,768
2090	4,043	1,254	0	0	1,471	6,768
2091	4,043	1,254	0	0	1,471	6,768
2092	4,054	1,257	0	0	1,475	6,787
2093	4,043	1,254	0	0	1,471	6,768
2094	4,043	1,254	0	0	1,471	6,768
2095	4,027	1,206	0	0	1,471	6,704
2096	0	0	0	0	0	0
Total	222,267	113,548	0	0	77,200	413,016

TABLE 3.1c
DECON ALTERNATIVE
SITE RESTORATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042	284	0	0	0	0	284
2043	1,203	0	0	0	0	1,203
2044	1,810	91	0	0	0	1,901
2045	1,937	100	0	0	0	2,037
2046	2,067	99	0	0	0	2,166
2047	1,229	59	0	0	0	1,288
2048	0	0	0	0	0	0
2049	0	0	0	0	0	0
2050	0	0	0	0	0	0
2051	11,612	7,715	163	0	588	20,077
2052	15,455	10,268	216	0	783	26,721
2053	3,800	2,525	53	0	192	6,571
2054-95	0	0	0	0	0	0
2096	2,552	1,691	36	0	83	4,363
Total	41,949	22,548	468	0	1,646	66,611

TABLE 3.2
SAFSTOR-1 ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042	19,847	633	875	13	10,811	32,178
2043	50,604	6,320	2,158	1,621	28,477	89,181
2044	19,960	9,462	608	407	9,447	39,884
2045	16,673	9,495	432	12	3,396	30,007
2046	16,673	9,495	432	12	3,396	30,007
2047	16,673	9,495	432	12	3,396	30,007
2048	16,718	9,521	433	12	3,405	30,089
2049	12,450	6,342	344	9	2,678	21,823
2050	6,259	1,718	216	6	1,625	9,823
2051	6,259	1,718	216	6	1,625	9,823
2052	6,276	1,723	216	6	1,630	9,850
2053	6,259	1,718	216	6	1,625	9,823
2054	6,259	1,718	216	6	1,625	9,823
2055	6,259	1,718	216	6	1,625	9,823
2056	6,276	1,723	216	6	1,630	9,850
2057	6,259	1,718	216	6	1,625	9,823
2058	6,259	1,718	216	6	1,625	9,823
2059	6,259	1,718	216	6	1,625	9,823
2060	6,276	1,723	216	6	1,630	9,850
2061	6,259	1,718	216	6	1,625	9,823
2062	6,259	1,718	216	6	1,625	9,823
2063	6,259	1,718	216	6	1,625	9,823
2064	6,276	1,723	216	6	1,630	9,850
2065	6,259	1,718	216	6	1,625	9,823
2066	6,259	1,718	216	6	1,625	9,823
2067	6,259	1,718	216	6	1,625	9,823
2068	6,276	1,723	216	6	1,630	9,850
2069	6,259	1,718	216	6	1,625	9,823
2070	6,259	1,718	216	6	1,625	9,823
2071	6,259	1,718	216	6	1,625	9,823
2072	6,276	1,723	216	6	1,630	9,850

TABLE 3.2 (continued)
SAFSTOR-1 ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2073	6,259	1,718	216	6	1,625	9,823
2074	6,259	1,718	216	6	1,625	9,823
2075	6,259	1,718	216	6	1,625	9,823
2076	6,276	1,723	216	6	1,630	9,850
2077	6,259	1,718	216	6	1,625	9,823
2078	6,259	1,718	216	6	1,625	9,823
2079	6,259	1,718	216	6	1,625	9,823
2080	6,276	1,723	216	6	1,630	9,850
2081	6,259	1,718	216	6	1,625	9,823
2082	6,259	1,718	216	6	1,625	9,823
2083	6,259	1,718	216	6	1,625	9,823
2084	6,276	1,723	216	6	1,630	9,850
2085	6,259	1,718	216	6	1,625	9,823
2086	6,259	1,718	216	6	1,625	9,823
2087	6,259	1,718	216	6	1,625	9,823
2088	6,276	1,723	216	6	1,630	9,850
2089	6,259	1,718	216	6	1,625	9,823
2090	6,259	1,718	216	6	1,625	9,823
2091	6,259	1,718	216	6	1,625	9,823
2092	6,276	1,723	216	6	1,630	9,850
2093	6,259	1,718	216	6	1,625	9,823
2094	6,259	1,718	216	6	1,625	9,823
2095	6,259	1,718	216	6	1,625	9,823
2096	9,892	1,144	594	9	1,731	13,370
2097	40,014	4,805	2,158	27	4,117	51,121
2098	47,617	28,230	2,084	17,139	16,808	111,878
2099	44,888	20,608	1,796	16,455	14,006	97,753
2100	42,024	8,369	1,618	10,556	8,036	70,604
2101	40,675	7,454	1,449	9,056	7,145	65,778
2102	26,230	5,587	345	14	1,313	33,489

TABLE 3.2 (continued)
SAFSTOR-1 ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2103	16,859	10,984	216	0	623	28,681
2104	10,115	6,590	129	0	374	17,208
Total	736,001	233,620	26,034	55,614	193,961	1,245,229

TABLE 3.2a
SAFSTOR-1 ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042	19,847	633	875	13	9,940	31,308
2043	50,419	5,764	2,158	1,621	26,331	86,292
2044	7,399	981	413	407	7,242	16,442
2045	2,874	494	216	12	1,190	4,785
2046	2,874	494	216	12	1,190	4,785
2047	2,874	494	216	12	1,190	4,785
2048	2,882	495	216	12	1,193	4,799
2049	2,874	439	216	9	1,184	4,722
2050	2,874	359	216	6	1,175	4,629
2051	2,874	359	216	6	1,175	4,629
2052	2,882	360	216	6	1,178	4,642
2053	2,874	359	216	6	1,175	4,629
2054	2,874	359	216	6	1,175	4,629
2055	2,874	359	216	6	1,175	4,629
2056	2,882	360	216	6	1,178	4,642
2057	2,874	359	216	6	1,175	4,629
2058	2,874	359	216	6	1,175	4,629
2059	2,874	359	216	6	1,175	4,629
2060	2,882	360	216	6	1,178	4,642
2061	2,874	359	216	6	1,175	4,629
2062	2,874	359	216	6	1,175	4,629
2063	2,874	359	216	6	1,175	4,629
2064	2,882	360	216	6	1,178	4,642
2065	2,874	359	216	6	1,175	4,629
2066	2,874	359	216	6	1,175	4,629
2067	2,874	359	216	6	1,175	4,629
2068	2,882	360	216	6	1,178	4,642
2069	2,874	359	216	6	1,175	4,629
2070	2,874	359	216	6	1,175	4,629
2071	2,874	359	216	6	1,175	4,629
2072	2,882	360	216	6	1,178	4,642

TABLE 3.2a (continued)
SAFSTOR-1 ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2073	2,874	359	216	6	1,175	4,629
2074	2,874	359	216	6	1,175	4,629
2075	2,874	359	216	6	1,175	4,629
2076	2,882	360	216	6	1,178	4,642
2077	2,874	359	216	6	1,175	4,629
2078	2,874	359	216	6	1,175	4,629
2079	2,874	359	216	6	1,175	4,629
2080	2,882	360	216	6	1,178	4,642
2081	2,874	359	216	6	1,175	4,629
2082	2,874	359	216	6	1,175	4,629
2083	2,874	359	216	6	1,175	4,629
2084	2,882	360	216	6	1,178	4,642
2085	2,874	359	216	6	1,175	4,629
2086	2,874	359	216	6	1,175	4,629
2087	2,874	359	216	6	1,175	4,629
2088	2,882	360	216	6	1,178	4,642
2089	2,874	359	216	6	1,175	4,629
2090	2,874	359	216	6	1,175	4,629
2091	2,874	359	216	6	1,175	4,629
2092	2,882	360	216	6	1,178	4,642
2093	2,874	359	216	6	1,175	4,629
2094	2,874	359	216	6	1,175	4,629
2095	2,874	359	216	6	1,175	4,629
2096	9,748	1,144	594	9	1,731	13,226
2097	39,049	4,805	2,158	27	4,117	50,156
2098	45,473	28,145	2,084	17,139	16,808	109,649
2099	42,907	20,507	1,796	16,455	14,006	95,670
2100	40,231	8,283	1,618	10,556	8,036	68,724
2101	39,136	7,380	1,449	9,056	7,145	64,166
2102	19,489	1,163	258	14	1,063	21,987

TABLE 3.2a (continued)
SAFSTOR-1 ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2103	121	0	0	0	0	121
2104	72	0	0	0	0	72
Total	460,553	97,729	24,415	55,614	156,453	794,764

TABLE 3.2b
SAFSTOR-1 ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042	0	0	0	0	870	870
2043	186	557	0	0	2,146	2,889
2044	12,560	8,481	195	0	2,206	23,442
2045	13,799	9,001	216	0	2,206	25,221
2046	13,799	9,001	216	0	2,206	25,221
2047	13,799	9,001	216	0	2,206	25,221
2048	13,837	9,025	216	0	2,212	25,290
2049	9,576	5,902	128	0	1,494	17,101
2050	3,385	1,360	0	0	450	5,194
2051	3,385	1,360	0	0	450	5,194
2052	3,394	1,363	0	0	451	5,209
2053	3,385	1,360	0	0	450	5,194
2054	3,385	1,360	0	0	450	5,194
2055	3,385	1,360	0	0	450	5,194
2056	3,394	1,363	0	0	451	5,209
2057	3,385	1,360	0	0	450	5,194
2058	3,385	1,360	0	0	450	5,194
2059	3,385	1,360	0	0	450	5,194
2060	3,394	1,363	0	0	451	5,209
2061	3,385	1,360	0	0	450	5,194
2062	3,385	1,360	0	0	450	5,194
2063	3,385	1,360	0	0	450	5,194
2064	3,394	1,363	0	0	451	5,209
2065	3,385	1,360	0	0	450	5,194
2066	3,385	1,360	0	0	450	5,194
2067	3,385	1,360	0	0	450	5,194
2068	3,394	1,363	0	0	451	5,209
2069	3,385	1,360	0	0	450	5,194
2070	3,385	1,360	0	0	450	5,194
2071	3,385	1,360	0	0	450	5,194
2072	3,394	1,363	0	0	451	5,209

TABLE 3.2b (continued)
SAFSTOR-1 ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2073	3,385	1,360	0	0	450	5,194
2074	3,385	1,360	0	0	450	5,194
2075	3,385	1,360	0	0	450	5,194
2076	3,394	1,363	0	0	451	5,209
2077	3,385	1,360	0	0	450	5,194
2078	3,385	1,360	0	0	450	5,194
2079	3,385	1,360	0	0	450	5,194
2080	3,394	1,363	0	0	451	5,209
2081	3,385	1,360	0	0	450	5,194
2082	3,385	1,360	0	0	450	5,194
2083	3,385	1,360	0	0	450	5,194
2084	3,394	1,363	0	0	451	5,209
2085	3,385	1,360	0	0	450	5,194
2086	3,385	1,360	0	0	450	5,194
2087	3,385	1,360	0	0	450	5,194
2088	3,394	1,363	0	0	451	5,209
2089	3,385	1,360	0	0	450	5,194
2090	3,385	1,360	0	0	450	5,194
2091	3,385	1,360	0	0	450	5,194
2092	3,394	1,363	0	0	451	5,209
2093	3,385	1,360	0	0	450	5,194
2094	3,385	1,360	0	0	450	5,194
2095	3,385	1,360	0	0	450	5,194
2096-04	0	0	0	0	0	0
Total	233,359	113,548	1,187	0	36,260	384,354

TABLE 3.2c
SAFSTOR-1 ALTERNATIVE
SITE RESTORATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2042-95	0	0	0	0	0	0
2096	143	0	0	0	0	143
2097	966	0	0	0	0	966
2098	2,144	84	0	0	0	2,228
2099	1,982	101	0	0	0	2,083
2100	1,794	86	0	0	0	1,880
2101	1,538	74	0	0	0	1,612
2102	6,741	4,424	87	0	251	11,502
2103	16,738	10,984	216	0	623	28,560
2104	10,043	6,590	129	0	374	17,136
Total	42,089	22,343	432	0	1,247	66,111

TABLE 3.3
SAFSTOR-2 ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2062	19,941	914	875	13	8,039	29,782
2063	50,701	6,611	2,158	1,621	24,414	85,504
2064	19,007	6,605	608	407	9,447	36,074
2065	15,718	6,630	432	12	3,396	26,187
2066	15,718	6,630	432	12	3,396	26,187
2067	15,718	6,630	432	12	3,396	26,187
2068	11,948	4,725	345	9	2,687	19,714
2069	6,315	1,886	216	6	1,625	10,047
2070	6,315	1,886	216	6	1,625	10,047
2071	6,315	1,886	216	6	1,625	10,047
2072	6,332	1,891	216	6	1,630	10,075
2073	6,315	1,886	216	6	1,625	10,047
2074	6,315	1,886	216	6	1,625	10,047
2075	6,315	1,886	216	6	1,625	10,047
2076	6,332	1,891	216	6	1,630	10,075
2077	6,315	1,886	216	6	1,625	10,047
2078	6,315	1,886	216	6	1,625	10,047
2079	6,315	1,886	216	6	1,625	10,047
2080	6,332	1,891	216	6	1,630	10,075
2081	6,315	1,886	216	6	1,625	10,047
2082	6,315	1,886	216	6	1,625	10,047
2083	6,315	1,886	216	6	1,625	10,047
2084	6,332	1,891	216	6	1,630	10,075
2085	6,315	1,886	216	6	1,625	10,047
2086	6,315	1,886	216	6	1,625	10,047
2087	6,315	1,886	216	6	1,625	10,047
2088	6,332	1,891	216	6	1,630	10,075
2089	6,315	1,886	216	6	1,625	10,047
2090	6,315	1,886	216	6	1,625	10,047
2091	6,315	1,886	216	6	1,625	10,047
2092	6,332	1,891	216	6	1,630	10,075

TABLE 3.3 (continued)
SAFSTOR-2 ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2093	6,315	1,886	216	6	1,625	10,047
2094	6,315	1,886	216	6	1,625	10,047
2095	6,315	1,886	216	6	1,625	10,047
2096	6,332	1,891	216	6	1,630	10,075
2097	6,315	1,886	216	6	1,625	10,047
2098	6,315	1,886	216	6	1,625	10,047
2099	6,315	1,886	216	6	1,625	10,047
2100	6,315	1,886	216	6	1,625	10,047
2101	6,315	1,886	216	6	1,625	10,047
2102	6,315	1,886	216	6	1,625	10,047
2103	6,315	1,886	216	6	1,625	10,047
2104	6,332	1,891	216	6	1,630	10,075
2105	6,315	1,886	216	6	1,625	10,047
2106	6,315	1,886	216	6	1,625	10,047
2107	6,315	1,886	216	6	1,625	10,047
2108	6,332	1,891	216	6	1,630	10,075
2109	6,315	1,886	216	6	1,625	10,047
2110	2,874	351	216	5	1,151	4,597
2111	2,874	351	216	5	1,151	4,597
2112	2,882	352	216	5	1,155	4,610
2113	2,874	351	216	5	1,151	4,597
2114	2,874	351	216	5	1,151	4,597
2115	2,874	351	216	5	1,151	4,597
2116	9,793	1,133	589	9	1,722	13,246
2117	39,999	4,799	2,158	27	4,117	51,100
2118	47,605	28,142	2,084	17,280	16,758	111,869
2119	44,907	20,689	1,797	16,620	14,046	98,060
2120	42,140	8,392	1,623	10,585	8,058	70,797
2121	40,675	7,454	1,449	9,056	7,145	65,778
2122	26,230	5,587	345	14	1,313	33,489

TABLE 3.3 (continued)
SAFSTOR-2 ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2123	16,859	10,984	216	0	623	28,681
2124	10,115	6,590	129	0	374	17,208
Total	703,381	211,998	25,818	55,939	182,510	1,179,646

TABLE 3.3a
SAFSTOR-2 ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2062	19,847	633	875	13	7,169	28,536
2063	50,419	5,764	2,158	1,621	22,267	82,228
2064	7,399	981	413	407	7,242	16,442
2065	2,874	494	216	12	1,190	4,785
2066	2,874	494	216	12	1,190	4,785
2067	2,874	494	216	12	1,190	4,785
2068	2,882	441	216	9	1,187	4,735
2069	2,874	359	216	6	1,175	4,629
2070	2,874	359	216	6	1,175	4,629
2071	2,874	359	216	6	1,175	4,629
2072	2,882	360	216	6	1,178	4,642
2073	2,874	359	216	6	1,175	4,629
2074	2,874	359	216	6	1,175	4,629
2075	2,874	359	216	6	1,175	4,629
2076	2,882	360	216	6	1,178	4,642
2077	2,874	359	216	6	1,175	4,629
2078	2,874	359	216	6	1,175	4,629
2079	2,874	359	216	6	1,175	4,629
2080	2,882	360	216	6	1,178	4,642
2081	2,874	359	216	6	1,175	4,629
2082	2,874	359	216	6	1,175	4,629
2083	2,874	359	216	6	1,175	4,629
2084	2,882	360	216	6	1,178	4,642
2085	2,874	359	216	6	1,175	4,629
2086	2,874	359	216	6	1,175	4,629
2087	2,874	359	216	6	1,175	4,629
2088	2,882	360	216	6	1,178	4,642
2089	2,874	359	216	6	1,175	4,629
2090	2,874	359	216	6	1,175	4,629
2091	2,874	359	216	6	1,175	4,629
2092	2,882	360	216	6	1,178	4,642

TABLE 3.3a (continued)
SAFSTOR-2 ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2093	2,874	359	216	6	1,175	4,629
2094	2,874	359	216	6	1,175	4,629
2095	2,874	359	216	6	1,175	4,629
2096	2,882	360	216	6	1,178	4,642
2097	2,874	359	216	6	1,175	4,629
2098	2,874	359	216	6	1,175	4,629
2099	2,874	359	216	6	1,175	4,629
2100	2,874	359	216	6	1,175	4,629
2101	2,874	359	216	6	1,175	4,629
2102	2,874	359	216	6	1,175	4,629
2103	2,874	359	216	6	1,175	4,629
2104	2,882	360	216	6	1,178	4,642
2105	2,874	359	216	6	1,175	4,629
2106	2,874	359	216	6	1,175	4,629
2107	2,874	359	216	6	1,175	4,629
2108	2,882	360	216	6	1,178	4,642
2109	2,874	359	216	6	1,175	4,629
2110	2,874	351	216	5	1,151	4,597
2111	2,874	351	216	5	1,151	4,597
2112	2,882	352	216	5	1,155	4,610
2113	2,874	351	216	5	1,151	4,597
2114	2,874	351	216	5	1,151	4,597
2115	2,874	351	216	5	1,151	4,597
2116	9,651	1,133	589	9	1,722	13,105
2117	39,036	4,799	2,158	27	4,117	50,138
2118	45,461	28,059	2,084	17,280	16,758	109,642
2119	42,925	20,588	1,797	16,620	14,046	95,976
2120	40,341	8,305	1,623	10,585	8,058	68,912
2121	39,136	7,380	1,449	9,056	7,145	64,166
2122	19,489	1,163	258	14	1,063	21,987

TABLE 3.3a (continued)
SAFSTOR-2 ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2123	121	0	0	0	0	121
2124	72	0	0	0	0	72
Total	460,553	97,548	24,415	55,939	149,461	787,916

TABLE 3.3b
SAFSTOR-2 ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2062	94	281	0	0	870	1,245
2063	282	847	0	0	2,146	3,276
2064	11,608	5,624	195	0	2,206	19,632
2065	12,844	6,136	216	0	2,206	21,401
2066	12,844	6,136	216	0	2,206	21,401
2067	12,844	6,136	216	0	2,206	21,401
2068	9,066	4,284	129	0	1,500	14,979
2069	3,441	1,527	0	0	450	5,418
2070	3,441	1,527	0	0	450	5,418
2071	3,441	1,527	0	0	450	5,418
2072	3,450	1,532	0	0	451	5,433
2073	3,441	1,527	0	0	450	5,418
2074	3,441	1,527	0	0	450	5,418
2075	3,441	1,527	0	0	450	5,418
2076	3,450	1,532	0	0	451	5,433
2077	3,441	1,527	0	0	450	5,418
2078	3,441	1,527	0	0	450	5,418
2079	3,441	1,527	0	0	450	5,418
2080	3,450	1,532	0	0	451	5,433
2081	3,441	1,527	0	0	450	5,418
2082	3,441	1,527	0	0	450	5,418
2083	3,441	1,527	0	0	450	5,418
2084	3,450	1,532	0	0	451	5,433
2085	3,441	1,527	0	0	450	5,418
2086	3,441	1,527	0	0	450	5,418
2087	3,441	1,527	0	0	450	5,418
2088	3,450	1,532	0	0	451	5,433
2089	3,441	1,527	0	0	450	5,418
2090	3,441	1,527	0	0	450	5,418
2091	3,441	1,527	0	0	450	5,418
2092	3,450	1,532	0	0	451	5,433

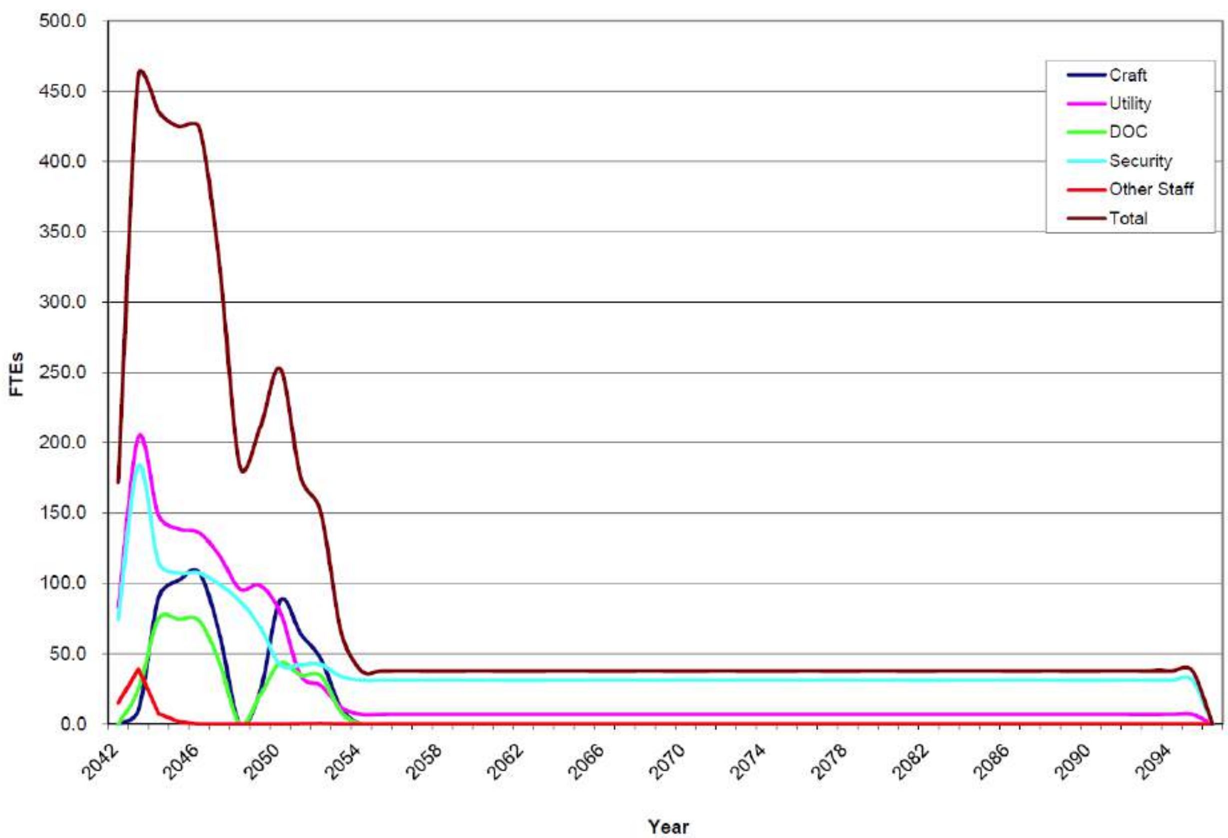
TABLE 3.3b (continued)
SAFSTOR-2 ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2016 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2093	3,441	1,527	0	0	450	5,418
2094	3,441	1,527	0	0	450	5,418
2095	3,441	1,527	0	0	450	5,418
2096	3,450	1,532	0	0	451	5,433
2097	3,441	1,527	0	0	450	5,418
2098	3,441	1,527	0	0	450	5,418
2099	3,441	1,527	0	0	450	5,418
2100	3,441	1,527	0	0	450	5,418
2101	3,441	1,527	0	0	450	5,418
2102	3,441	1,527	0	0	450	5,418
2103	3,441	1,527	0	0	450	5,418
2104	3,450	1,532	0	0	451	5,433
2105	3,441	1,527	0	0	450	5,418
2106	3,441	1,527	0	0	450	5,418
2107	3,441	1,527	0	0	450	5,418
2108	3,450	1,532	0	0	451	5,433
2109	3,441	1,527	0	0	450	5,418
2110-24	0	0	0	0	0	0
Total	200,739	92,107	971	0	31,802	325,619

TABLE 3.3c
SAFSTOR-2 ALTERNATIVE
SITE RESTORATION EXPENDITURES
(thousands, 2016 dollars)

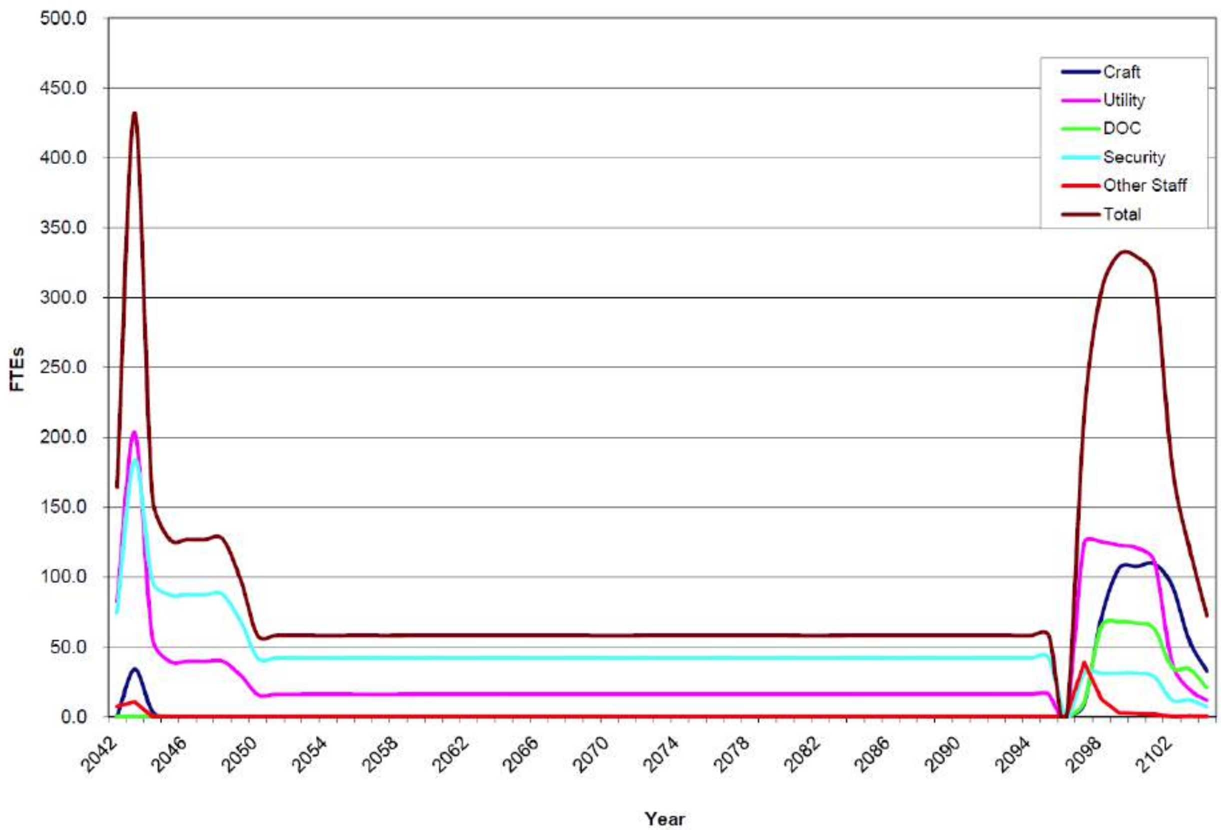
Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2062-15	0	0	0	0	0	0
2116	141	0	0	0	0	141
2117	962	0	0	0	0	962
2118	2,143	84	0	0	0	2,227
2119	1,983	101	0	0	0	2,084
2120	1,799	86	0	0	0	1,885
2121	1,538	74	0	0	0	1,612
2122	6,741	4,424	87	0	251	11,502
2123	16,738	10,984	216	0	623	28,560
2124	10,043	6,590	129	0	374	17,136
Total	42,089	22,343	432	0	1,247	66,111

FIGURE 3.1
DECON SCENARIO
V.C. SUMMER NUCLEAR STATION
MANPOWER LEVELS



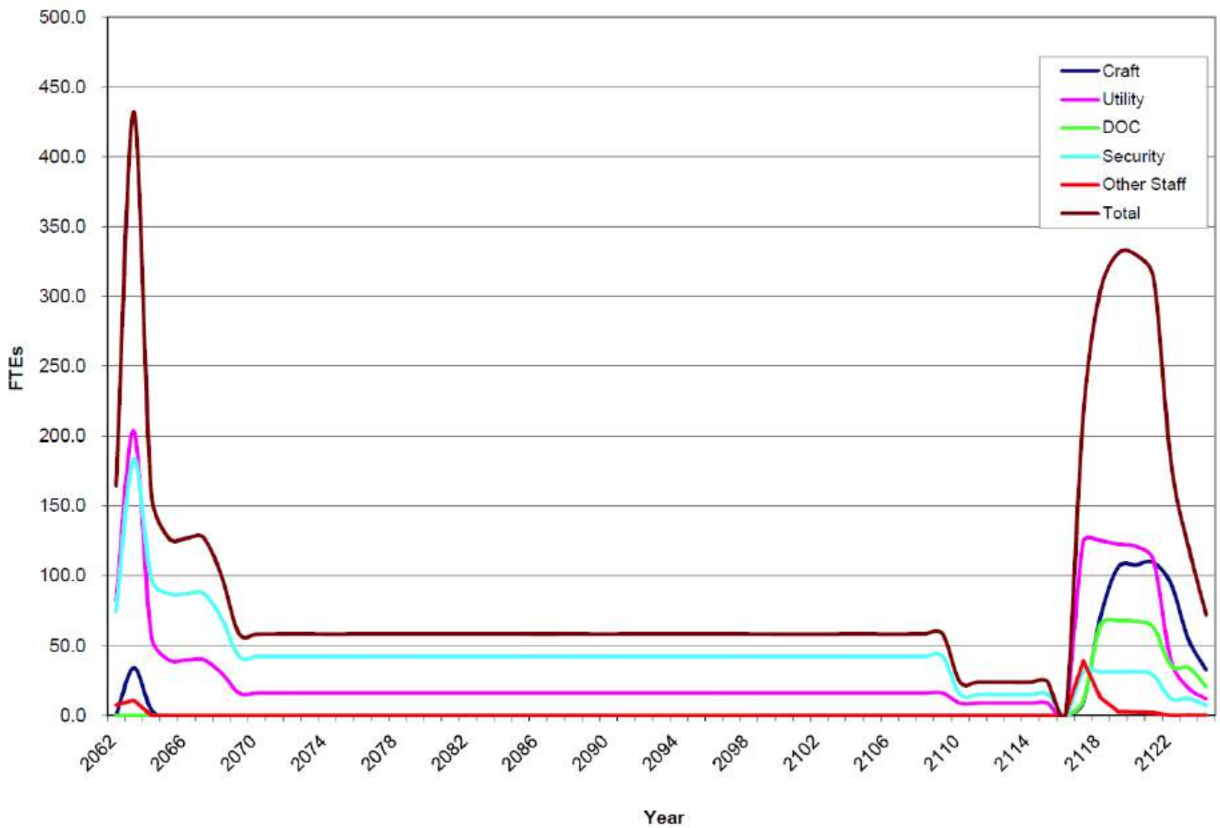
Note that the labor hour basis of this chart was taken from Appendix C; however not all line items in Appendix C have labor hour values available (e.g. spent fuel canister loading estimates from SCE&G)

FIGURE 3.2
SAFSTOR-1 SCENARIO
V.C. SUMMER NUCLEAR STATION
MANPOWER LEVELS



Note that the labor hour basis of this chart was taken from Appendix D; however not all line items in Appendix D have labor hour values available (e.g. spent fuel canister loading estimates from SCE&G)

FIGURE 3.3
SAFSTOR-2 SCENARIO
V.C. SUMMER NUCLEAR STATION
MANPOWER LEVELS



Note that the labor hour basis of this chart was taken from Appendix E; however not all line items in Appendix E have labor hour values available (e.g. spent fuel canister loading estimates from SCE&G)

4. SCHEDULE ESTIMATE

The schedules for the decommissioning scenarios considered in this analysis follow the sequences presented in the AIF/NESP-036 study, with minor changes to reflect recent experience and site-specific constraints. In addition, the scheduling has been revised to reflect the spent fuel management described in Section 3.4.1.

A schedule or sequence of activities for the DECON alternative is presented in Figure 4.1. The scheduling sequence is based on the fuel being removed from the spent fuel pool within seven years. The key activities listed in the schedule do not reflect a one-to-one correspondence with those activities in the cost table, but reflect dividing some activities for clarity and combining others for convenience. The schedule was prepared using the "Microsoft Project Professional" computer software.[35]

4.1 SCHEDULE ESTIMATE ASSUMPTIONS

The schedule reflects the results of a precedence network developed for the site decommissioning activities, i.e., a PERT (Program Evaluation and Review Technique) Software Package. The work activity durations used in the precedence network reflect the actual man-hour estimates from the cost table, adjusted by stretching certain activities over their slack range and shifting the start and end dates of others. The following assumptions were made in the development of the decommissioning schedule:

- The fuel handling building is isolated until such time that all spent fuel has been discharged from the spent fuel pool to the ISFSI. Decontamination and dismantling of the storage pool is initiated once the transfer of spent fuel is complete (DECON option).
- All work (except reactor vessel and reactor vessel internals removal and the spent fuel loading campaigns) is performed during an 8-hour workday, 5 days per week, with no overtime.
- Reactor and internals removal activities are performed by using separate crews for different activities working on different shifts, with a corresponding backshift charge for the second shift.
- Multiple crews work parallel activities to the maximum extent possible, consistent with optimum efficiency, adequate access for cutting, removal and laydown space, and with the stringent safety measures necessary during demolition of heavy components and structures.

- For plant systems removal, the systems with the longest removal durations in areas on the critical path are considered to determine the duration of the activity.

4.2 PROJECT SCHEDULE

The period-dependent costs presented in the detailed cost tables are based upon the durations developed in the schedules for decommissioning. Durations are established between several milestones in each project period; these durations are used to establish a critical path for the entire project. In turn, the critical path duration for each period is used as the basis for determining the period-dependent costs. A second critical path is shown for the spent fuel storage period, which determines the release of the fuel handling building for final decontamination.

Project timelines are provided in Figures 4.2 through 4.4, with milestone dates based on the shutdown date. The fuel pool is emptied seven years after shutdown, while ISFSI operations continue until the DOE can complete the transfer of assemblies. Deferred decommissioning in the SAFSTOR scenario is assumed to commence so that the operating license is terminated within a 60-year period from the cessation of plant operations.

FIGURE 4.1
ACTIVITY SCHEDULE

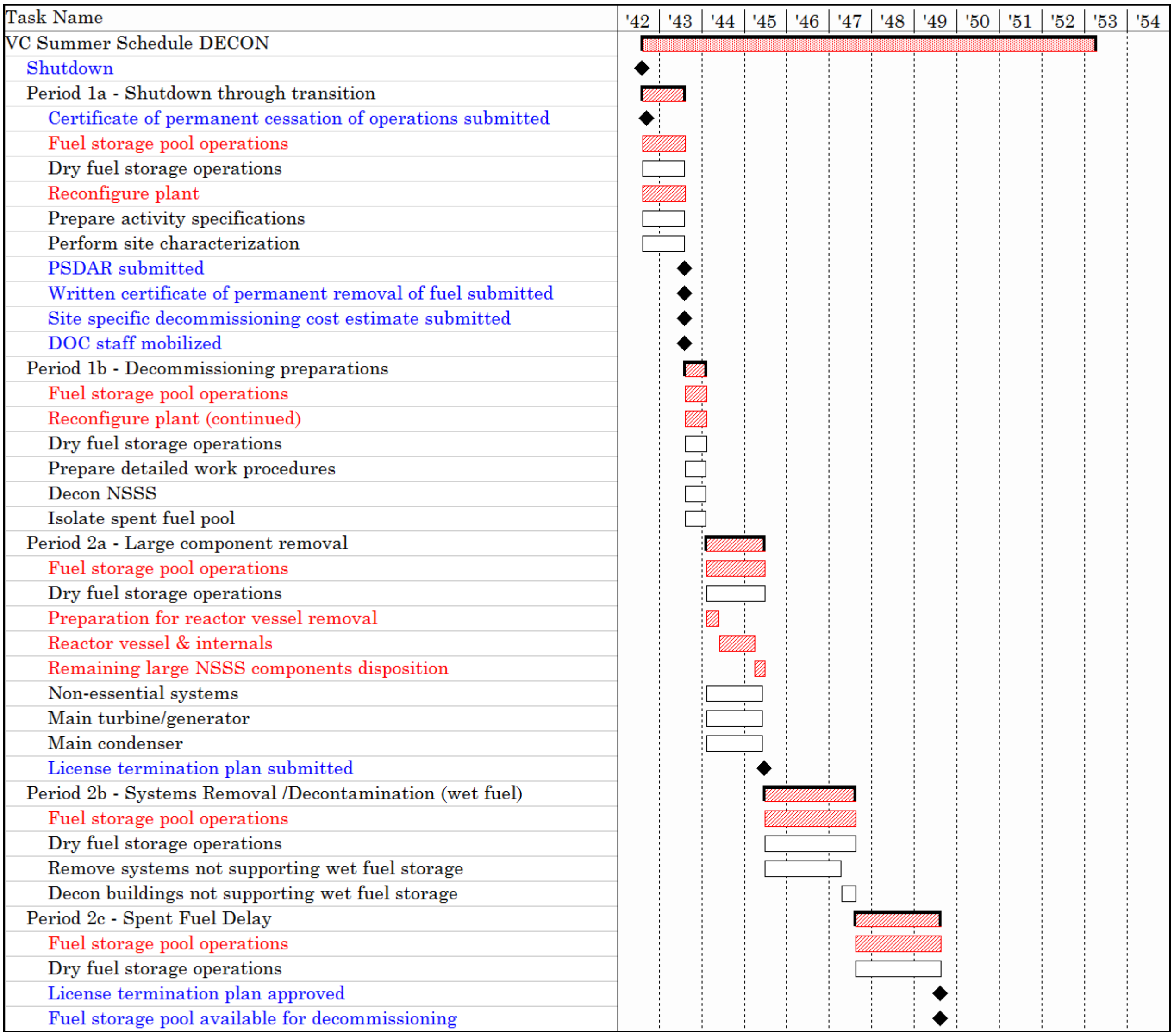
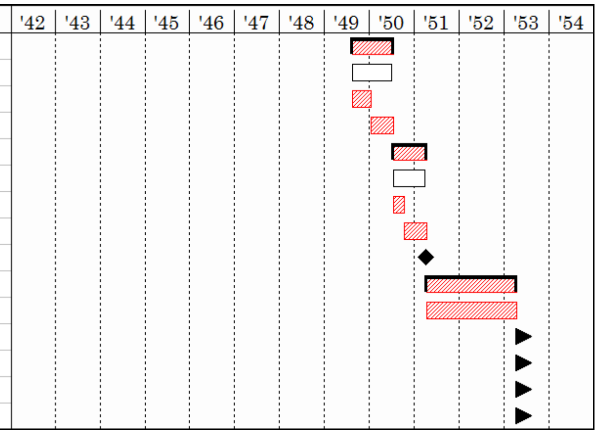


FIGURE 4.1 (continued)
ACTIVITY SCHEDULE

Task Name
Period 2d - Decontamination following wet fuel storage
Dry fuel storage operations
Remove remaining systems
Decon wet fuel storage area
Period 2f - Plant license termination
Dry fuel storage operations
Final Site Survey
NRC review & approval
Part 50 license terminated
Period 3b - Site restoration
Building demolitions
Period 3c - Fuel Storage Ops / Shipping (Mar 2053 - Dec 2095)
Period 3d - GTCC Shipping (Dec 2095)
Period 3e - ISFSI Decontamination (Jan 2096 - May 2096)
Period 3f - ISFSI Restoration (May 2096 - Jul 2096)



LEGEND

1. Red scheduling bars indicate critical path activities
2. Blue scheduling bars associated with major decommissioning periods, e.g., Period 1a, indicate overall duration of that period
3. Diamond symbols indicate major milestones

FIGURE 4.2
DECOMMISSIONING TIMELINE
DECON
(not to scale)

Shutdown August 6, 2042

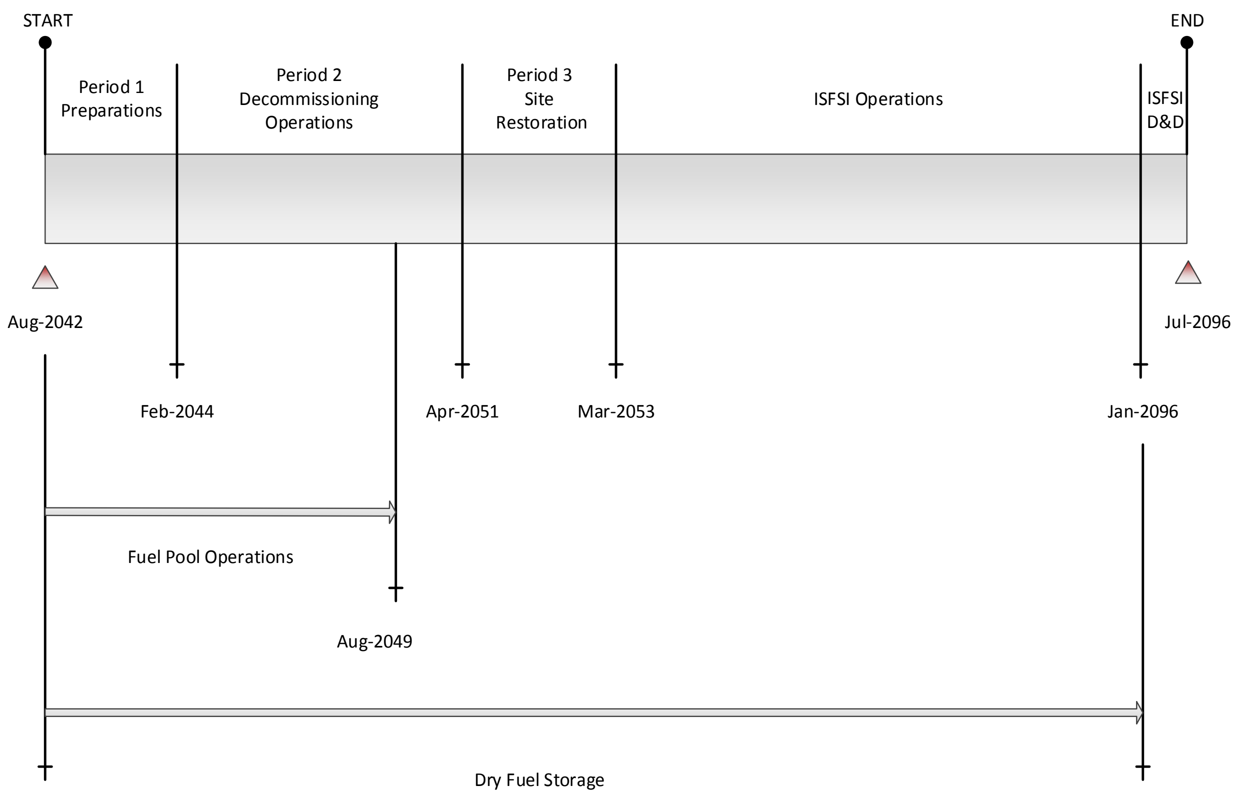


FIGURE 4.3
DECOMMISSIONING TIMELINE
SAFSTOR-1
(not to scale)

Shutdown August 6, 2042

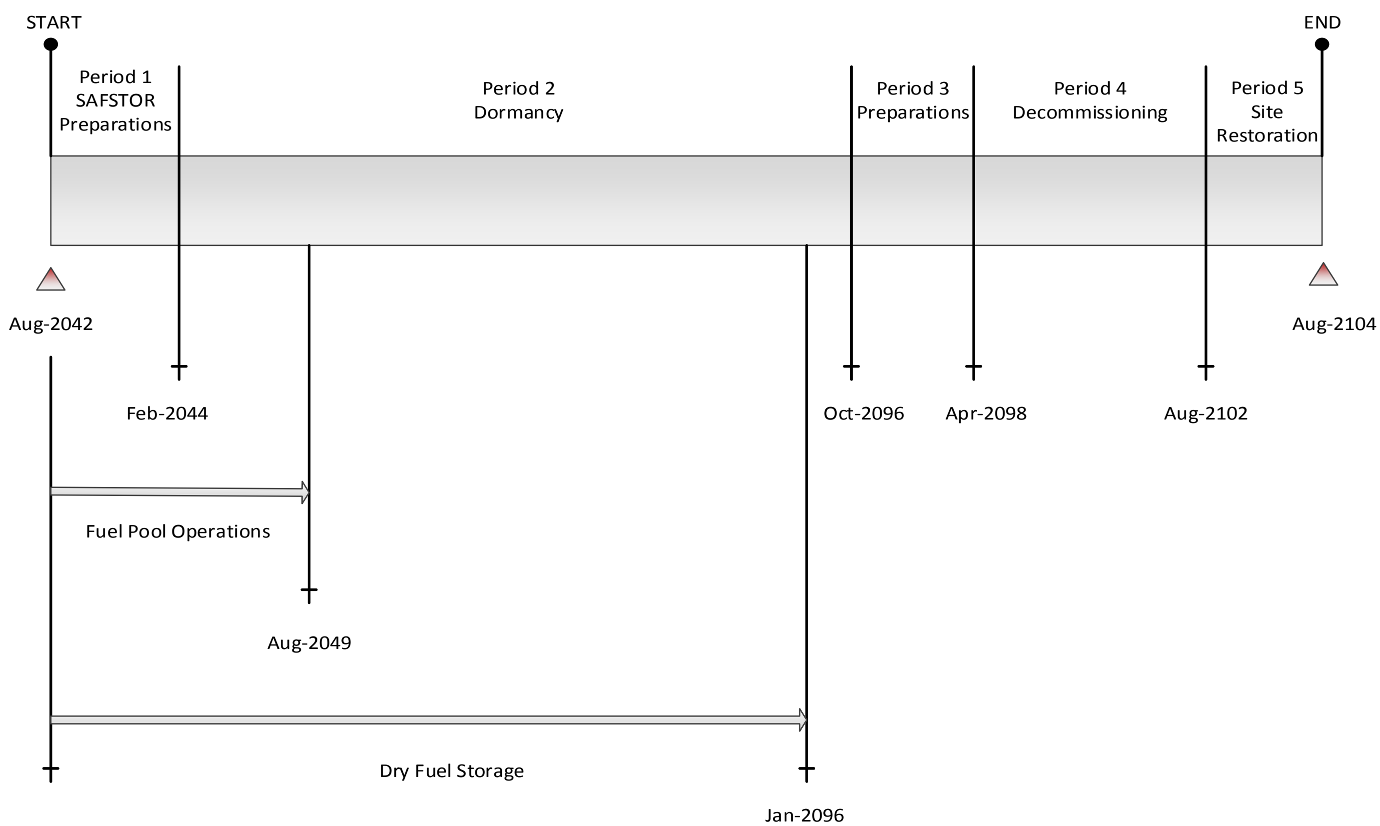
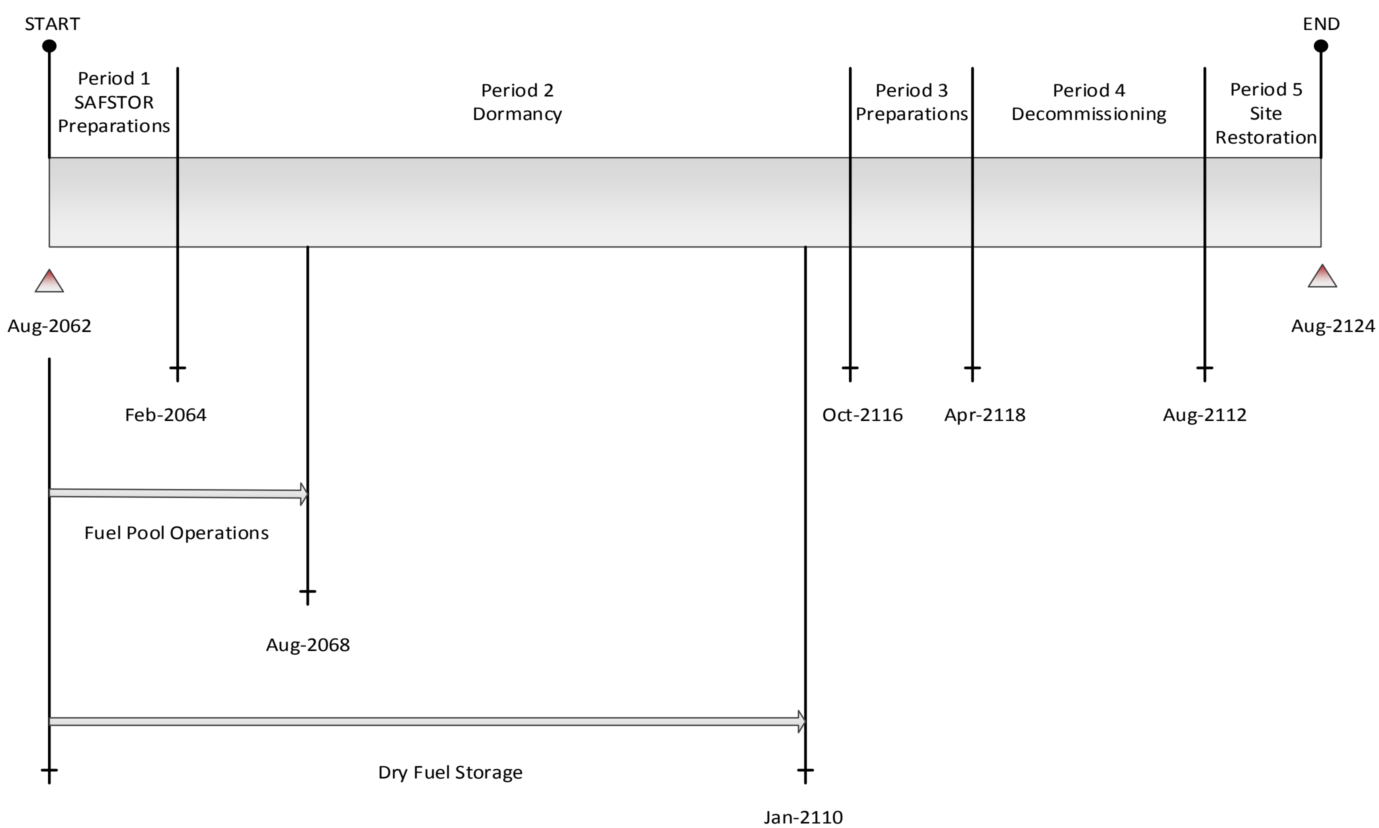


FIGURE 4.4
DECOMMISSIONING TIMELINE
SAFSTOR-2
(not to scale)

Shutdown August 6, 2062



5. RADIOACTIVE WASTES

The objectives of the decommissioning process are the removal of all radioactive material from the site that would restrict its future use and the termination of the NRC license. This currently requires the remediation of all radioactive material at the site in excess of applicable legal limits. Under the Atomic Energy Act,[36] the NRC is responsible for protecting the public from sources of ionizing radiation. Title 10 of the Code of Federal Regulations delineates the production, utilization, and disposal of radioactive materials and processes. In particular, Part 71 defines radioactive material as it pertains to transportation and Part 61 specifies its disposition.

Most of the materials being transported for controlled burial are categorized as Low Specific Activity (LSA) or Surface Contaminated Object (SCO) materials containing Type A quantities, as defined in 49 CFR Parts 173-178. Shipping containers are required to be Industrial Packages (IP-1, IP-2 or IP-3, as defined in 10 CFR §173.411). For this study, commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations.

The destinations for the various waste streams from decommissioning are identified in Figures 5.1 and 5.2. The volumes are shown on a line-item basis in Appendices C through F and summarized in Tables 5.1 through 5.3. The quantified waste volume summaries shown in these tables are consistent with §61 classifications. The volumes are calculated based on the exterior dimensions for containerized material and on the displaced volume of components serving as their own waste containers.

The reactor vessel and internals are categorized as large quantity shipments and, accordingly, will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping casks.

No process system containing/handling radioactive substances at shutdown is presumed to meet material release criteria by decay alone (i.e., systems radioactive at shutdown will still be radioactive over the time period during which the decommissioning is accomplished, due to the presence of long-lived radionuclides). While the dose rates decrease with time, radionuclides such as ^{137}Cs will still control the disposition requirements.

The waste material produced in the decontamination and dismantling of the nuclear plant is primarily generated during Period 2 of DECON and Period 4 of SAFSTOR. Material that is considered potentially contaminated when removed from the radiological controlled area is sent to processing facilities in Tennessee for conditioning and disposal. Heavily contaminated components and activated materials are routed for controlled disposal. The disposal volumes reported in the tables reflect the savings resulting from reprocessing and recycling.

For purposes of constructing the estimates, the current cost for disposal at Barnwell, South Carolina was used for a majority of the radioactive waste produced from the decommissioning activities. Separate rates were used for containerized waste and large components. Demolition debris including miscellaneous steel, scaffolding, and concrete was disposed of at a bulk rate. The decommissioning waste stream also included resins and dry active waste.

Disposal costs for the higher activity waste (Class B and C) were based upon current agreement with Barnwell, South Carolina.

A small quantity of material generated during the VCSNS decommissioning will not be considered suitable for near-surface disposal, and is assumed to be disposed of in a geologic repository, in a manner similar to that envisioned for spent fuel disposal. Such material, known as Greater-Than-Class-C or GTCC material, is estimated to require four spent fuel storage canisters (or the equivalent) to dispose of the most radioactive portions of the reactor vessel internals. The volume and weight reported in Tables 5.1 through 5.3 represent the packaged weight and volume of the spent fuel storage canisters.

FIGURE 5.1
RADIOACTIVE WASTE DISPOSITION

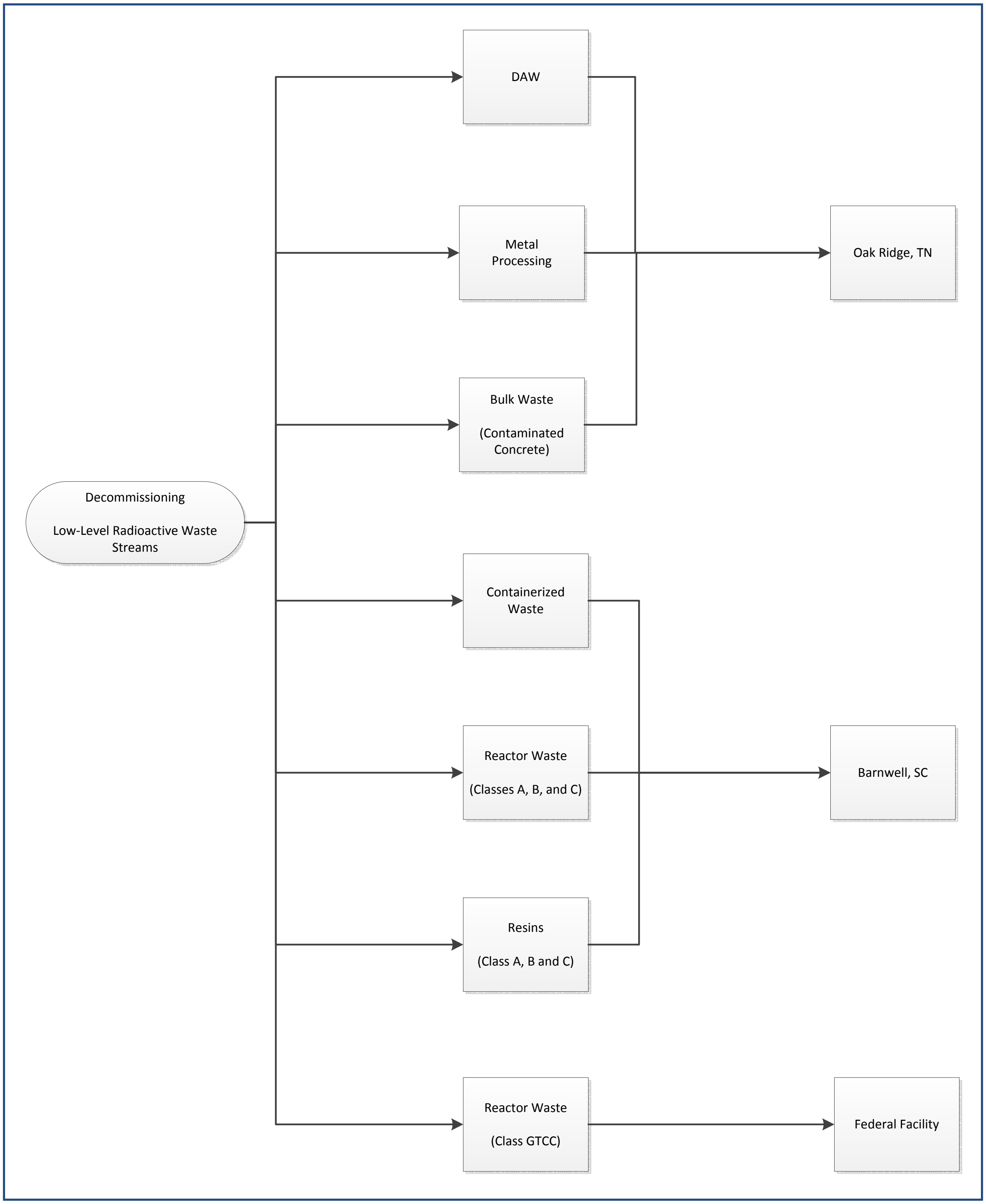


FIGURE 5.2
DECOMMISSIONING WASTE DESTINATIONS
RADIOLOGICAL

The figure indicates the destinations for the low-level radioactive waste designated for direct disposal (Barnwell, South Carolina and Oak Ridge, Tennessee) and processing/recovery (Oak Ridge, Tennessee).

Disposition of the Class B and C low-level radioactive waste will be at the Atlantic Compact's disposal facility in Barnwell, South Carolina.

Disposal options (and destinations) for GTCC are still being evaluated.

TABLE 5.1
DECON ALTERNATIVE
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Weight (pounds)
Low-Level Radioactive Waste (near-surface disposal)				
Large Components [2]	Barnwell	A	62,080	5,496,642
Containerized	Barnwell	A	101,192	6,783,368
DAW and Concrete Debris	Oak Ridge	A	64,876	3,871,613
Reactor Vessel and Resins	Barnwell	B	1,294	139,174
Reactor Vessel	Barnwell	C	281	34,277
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,773	363,061
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	88,702	3,505,985
Total [3]			320,199	20,194,120

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55

[2] Steam generators, pressurizer and reactor coolant pumps

[3] Columns may not add due to rounding

TABLE 5.2
SAFSTOR-1 ALTERNATIVE
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Weight (pounds)
Low-Level Radioactive Waste (near-surface disposal)				
Large Components [2]	Barnwell	A	62,080	5,457,919
Containerized	Barnwell	A	98,888	6,639,541
DAW and Concrete Debris	Oak Ridge	A	64,725	3,577,777
Reactor Vessel and Resins	Barnwell	B	376	37,848
Reactor Vessel	Barnwell	C	281	34,277
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,773	363,061
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	92,830	3,700,020
Total [3]			320,952	19,810,443

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55

[2] Steam generators, pressurizer and reactor coolant pumps

[3] Columns may not add due to rounding

TABLE 5.3
SAFSTOR-2 ALTERNATIVE
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Weight (pounds)
Low-Level Radioactive Waste (near-surface disposal)				
Large Components [2]	Barnwell	A	62,080	5,457,919
Containerized	Barnwell	A	98,512	6,607,221
DAW and Concrete Debris	Oak Ridge	A	64,553	3,574,342
Reactor Vessel and Resins	Barnwell	B	751	70,170
Reactor Vessel	Barnwell	C	281	34,277
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,773	363,061
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	92,830	3,700,020
Total [3]			320,780	19,807,010

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55

[2] Steam generators, pressurizer and reactor coolant pumps

[3] Columns may not add due to rounding

6. RESULTS

The analysis to estimate the costs to decommission VCSNS relied upon the site-specific, technical information developed for a previous analysis prepared in 2012. While not an engineering study, the estimates provide the owners with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The estimates described in this report are based on numerous fundamental assumptions, including regulatory requirements, project contingencies, low-level radioactive waste disposal practices, high-level radioactive waste management options, and site restoration requirements.

The cost projected to promptly decommission the station, dismantle the structures, and manage the spent fuel is estimated to be $1,108.8 million. The majority of this cost (approximately 56.7%) is associated with the physical decontamination and dismantling of the nuclear plant so that the operating license can be terminated. Another 37.3% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 6.0% is for the demolition of the designated structures and limited restoration of the site.

The cost projected for deferred decommissioning (SAFSTOR-1) is estimated to be $1,245.2 million. The majority of this cost (approximately 63.8%) is associated with placing the plant in storage, ongoing caretaking of the plant during dormancy, and the eventual physical decontamination and dismantling of the nuclear plant so that the operating license can be terminated. Another 30.9% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 5.3% is for the demolition of the designated structures and limited restoration of the site.

The cost projected for deferred decommissioning (SAFSTOR-2) is estimated to be $1,179.6 million. The majority of this cost (approximately 66.8%) is associated with placing the plant in storage, ongoing caretaking of the plant during dormancy, and the eventual physical decontamination and dismantling of the nuclear plant so that the operating license can be terminated. Another 27.6% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 5.6% is for the demolition of the designated structures and limited restoration of the site.

The primary cost contributors, identified in Tables 6.1, 6.2 and 6.3, are either labor-related or associated with the management and disposition of the radioactive waste. Program management is the largest single contributor to the overall cost. The magnitude of the expense is a function of both the size of the organization required to manage the decommissioning, as well as the duration of the program. It is assumed, for purposes of this analysis, that SCE&G Operations will oversee the decommissioning program and manage the decommissioning labor force (with the exception of the ISFSI decommissioning discussed in Section 3.4.1). The size and composition of the management organization varies with the decommissioning phase and associated site activities. However, once the operating license is amended or terminated, the staff is substantially reduced for the conventional demolition and restoration of the site, and the long-term care of the spent fuel (for the DECON alternative).

As described in this report, the spent fuel pool will remain operational for seven years following the cessation of operations. The pool will be isolated and an independent spent fuel island created. This will allow decommissioning operations to proceed in and around the pool area. Over the seven year period, the spent fuel will be packaged into canisters assumed to be loaded into a DOE-provided transport cask or relocated to the ISFSI.

The cost for waste disposal includes only those costs associated with the controlled disposition of the low-level radioactive waste generated from decontamination and dismantling activities, including plant equipment and components, structural material, filters, resins and dry-active waste. As described in Section 5, disposition of the majority of the low-level radioactive material requiring controlled disposal is at the Barnwell facility. Highly activated components, requiring additional isolation from the environment (GTCC), are packaged for geologic disposal. The cost of geologic disposal is based upon a cost equivalent for spent fuel.

A significant portion of the metallic waste is designated for additional processing and treatment at an off-site facility. Processing reduces the volume of material requiring controlled disposal through such techniques and processes as survey and sorting, decontamination, and volume reduction. The material that cannot be unconditionally released is packaged for controlled disposal at one of the currently operating facilities. The cost identified in the summary tables for processing is all-inclusive, incorporating the ultimate disposition of the material.

Removal costs reflect the labor-intensive nature of the decommissioning process, as well as the management controls required to ensure a safe and successful program. Decontamination and packaging costs also have a large labor component that is based upon prevailing wages. Non-radiological demolition is a natural extension of the decommissioning process. The methods employed in decontamination and dismantling are generally destructive and indiscriminate in inflicting collateral damage. With a work force mobilized to support decommissioning operations, non-radiological demolition can be an integrated activity and a logical expansion of the work being performed in the process of terminating the operating license.

The reported cost for transport includes the tariffs and surcharges associated with moving large components and/or overweight shielded casks overland, as well as the general expense, e.g., labor and fuel, of transporting material to the destinations identified in this report. For purposes of this analysis, material is primarily moved overland by truck.

Decontamination is used to reduce the plant's radiation fields and minimize worker exposure. Slightly contaminated material or material located within a contaminated area is sent to an off-site processing center, i.e., this analysis does not assume that contaminated plant components and equipment can be decontaminated for uncontrolled release in-situ. Centralized processing centers have proven to be a more economical means of handling the large volumes of material produced in the dismantling of a nuclear plant.

License termination survey costs are associated with the labor intensive and complex activity of verifying that contamination has been removed from the site to the levels specified by the regulating agency. This process involves a systematic survey of all remaining plant surface areas and surrounding environs, sampling, isotopic analysis, and documentation of the findings. The status of any plant components and materials not removed in the decommissioning process will also require confirmation and will add to the expense of surveying the facilities alone.

The remaining costs include allocations for heavy equipment and temporary services, as well as for other expenses such as regulatory fees and the premiums for nuclear insurance. While site operating costs are greatly reduced following the final cessation of plant operations, certain administrative functions do need to be maintained either at a basic functional or regulatory level.

TABLE 6.1
DECON ALTERNATIVE
DECOMMISSIONING COST ELEMENTS
(thousands of 2016 dollars)

Cost Element	Total	Percentage
Decontamination	11,582	1.0
Removal	121,160	10.9
Packaging	25,330	2.3
Transportation	6,625	0.6
Waste Disposal	71,130	6.4
Off-site Waste Processing	8,306	0.7
Program Management [1]	319,191	28.8
Site Security	196,113	17.7
Spent Fuel Pool Isolation	13,062	1.2
Spent Fuel (Direct Expenditures) [2]	192,320	17.3
Insurance and Regulatory Fees	46,838	4.2
Energy	15,468	1.4
Characterization and Licensing Surveys	25,590	2.3
Property Taxes	14,921	1.3
Miscellaneous Equipment / Site Services	7,499	0.7
Corporate Overhead	23,031	2.1
Non-Labor Overhead	10,600	1.0
Total [3]	1,108,765	100.0

Cost Element	Total	Percentage
License Termination	629,138	56.7
Spent Fuel Management	413,016	37.3
Site Restoration	66,611	6.0
Total [3]	1,108,765	100.0

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer costs/spent fuel pool O&M and EP fees
[3] Columns may not add due to rounding

TABLE 6.2
SAFSTOR-1 ALTERNATIVE
DECOMMISSIONING COST ELEMENTS
(thousands of 2016 dollars)

Cost Element	Total	Percentage
Decontamination	13,671	1.1
Removal	123,209	9.9
Packaging	18,934	1.5
Transportation	6,075	0.5
Waste Disposal	60,233	4.8
Off-site Waste Processing	8,765	0.7
Program Management [1]	379,778	30.5
Site Security	237,464	19.1
Spent Fuel Pool Isolation	13,062	1.0
Spent Fuel (Direct Expenditures) [2]	174,982	14.1
Insurance and Regulatory Fees	65,519	5.3
Energy	26,092	2.1
Characterization and Licensing Surveys	25,950	2.1
Property Taxes	14,921	1.2
Miscellaneous Equipment / Site Services	31,189	2.5
Corporate Overhead	31,163	2.5
Non-Labor Overhead	14,223	1.1
Total [3]	1,245,229	100.0

Cost Element	Total	Percentage
License Termination	794,764	63.8
Spent Fuel Management	384,354	30.9
Site Restoration	66,111	5.3
Total [3]	1,245,229	100.0

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer costs/spent fuel pool O&M and EP fees
[3] Columns may not add due to rounding

TABLE 6.3
SAFSTOR-2 ALTERNATIVE
DECOMMISSIONING COST ELEMENTS
(thousands of 2016 dollars)

Cost Element	Total	Percentage
Decontamination	13,671	1.2
Removal	123,031	10.4
Packaging	18,930	1.6
Transportation	6,074	0.5
Waste Disposal	60,558	5.1
Off-site Waste Processing	8,765	0.7
Program Management [1]	369,934	31.4
Site Security	221,835	18.8
Spent Fuel Pool Isolation	13,062	1.1
Spent Fuel (Direct Expenditures) [2]	143,595	12.2
Insurance and Regulatory Fees	65,219	5.5
Energy	25,876	2.2
Characterization and Licensing Surveys	25,950	2.2
Property Taxes	8,085	0.7
Miscellaneous Equipment / Site Services	31,189	2.6
Corporate Overhead	30,098	2.6
Non-Labor Overhead	13,773	1.2
Total [3]	1,179,646	100.0

Cost Element	Total	Percentage
License Termination	787,916	66.8
Spent Fuel Management	325,619	27.6
Site Restoration	66,111	5.6
Total [3]	1,179,646	100.0

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer costs/spent fuel pool O&M and EP fees
[3] Columns may not add due to rounding

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7. REFERENCES
(continued)

12. U.S. Court of Appeals for the District Of Columbia Circuit, In Re: Aiken County, et al, Aug. 2013, http://www.cadc.uscourts.gov/internet/opinions.nsf/BAE0CF34F762EBD985257BC6004DEB18/$file/11-1271-1451347.pdf

13. In 2008, the DOE issued a report to Congress in which it concluded that it did not have authority, under present law, to accept spent nuclear fuel for interim storage from decommissioned commercial nuclear power reactor sites. However, the Blue Ribbon Commission, in its final report, noted that: "[A]ccepting spent fuel according to the OFF [Oldest Fuel First] priority ranking instead of giving priority to shutdown reactor sites could greatly reduce the cost savings that could be achieved through consolidated storage if priority could be given to accepting spent fuel from shutdown reactor sites before accepting fuel from still-operating plants. …. The magnitude of the cost savings that could be achieved by giving priority to shutdown sites appears to be large enough (i.e., in the billions of dollars) to warrant DOE exercising its right under the Standard Contract to move this fuel first." For planning purposes only, the estimates do not assume that VCSNS, as a permanently shutdown unit, will receive priority; the fuel removal schedule assumed in this estimate is based upon DOE acceptance of fuel according to the "Oldest Fuel First" priority ranking. The plant owners will seek the most expeditious means of removing fuel from the site when DOE commences performance.

14. U.S. Code of Federal Regulations, Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," Subpart 54 (bb), "Conditions of Licenses"

15. U.S. Code of Federal Regulations, Title 10, Part 72, Subpart K, "General License for Storage of Spent Fuel at Power Reactor Sites"

16. "Low Level Radioactive Waste Policy Act," Public Law 96-573, 1980

17. "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, 1986

18. Waste is classified in accordance with U.S. Code of Federal Regulations, Title 10, Part 61.55

19. U.S. Code of Federal Regulations, Title 10, Part 20, Subpart E, "Final Rule, Radiological Criteria for License Termination," 62 Fed. Reg. 39058, July 21, 1997

7. REFERENCES
(continued)

20. "Establishment of Cleanup Levels for CERCLA Sites with Radioactive Contamination," EPA Memorandum OSWER No. 9200.4-18, August 22, 1997

21. U.S. Code of Federal Regulations, Title 40, Part 141.16, "Maximum contaminant levels for beta particle and photon radioactivity from man-made radionuclides in community water systems"

22. "Memorandum of Understanding Between the Environmental Protection Agency and the Nuclear Regulatory Commission: Consultation and Finality on Decommissioning and Decontamination of Contaminated Sites," OSWER 9295.8-06a, October 9, 2002

23. "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)," NUREG/CR-1575, Rev. 1, EPA 402-R-97-016, Rev. 1, August 2000

24. T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986

25. W.J. Manion and T.S. LaGuardia, "Decommissioning Handbook," U.S. Department of Energy, DOE/EV/10128-1, November 1980

26. "Building Construction Cost Data 2016," Robert Snow Means Company, Inc., Kingston, Massachusetts

27. Project and Cost Engineers' Handbook, Second Edition, p. 239, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, 1984

28. "Strategy for Management and Disposal of Greater-Than-Class C Low-Level Radioactive Waste," Federal Register Volume 60, Number 48 (p 13424 et seq.), March 1995

29. U.S. Department of Transportation, Title 49 of the Code of Federal Regulations, "Transportation," Parts 173 through 178

30. Tri-State Motor Transit Company, published tariffs

31. J.C. Evans et al., "Long-Lived Activation Products in Reactor Materials" NUREG/CR-3474, Pacific Northwest Laboratory for the Nuclear Regulatory Commission, August 1984

7. REFERENCES
(continued)

32. R.I. Smith, G.J. Konzek, W.E. Kennedy, Jr., "Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station," NUREG/CR-0130 and addenda, Pacific Northwest Laboratory for the Nuclear Regulatory Commission, June 1978

33. H.D. Oak, et al., "Technology, Safety and Costs of Decommissioning a Reference Boiling Water Reactor Power Station," NUREG/CR-0672 and addenda, Pacific Northwest Laboratory for the Nuclear Regulatory Commission, June 1980

34. SECY-00-0145, "Integrated Rulemaking Plan for Nuclear Power Plant Decommissioning," June 2000

35. "Microsoft Project Professional 2013," Microsoft Corporation, Redmond, WA

36. "Atomic Energy Act of 1954," (68 Stat. 919)

APPENDIX A

UNIT COST FACTOR DEVELOPMENT

APPENDIX A
UNIT COST FACTOR DEVELOPMENT

Example: Unit Factor for Removal of Contaminated Heat Exchanger < 3,000 lbs.

1. SCOPE

Heat exchangers weighing < 3,000 lbs. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the waste processing area.

2. CALCULATIONS

Act ID	Activity Description	Activity Duration (minutes)	Critical Duration (minutes)*
a	Remove insulation	60	(b)
b	Mount pipe cutters	60	60
c	Install contamination controls	20	(b)
d	Disconnect inlet and outlet lines	60	60
e	Cap openings	20	(d)
f	Rig for removal	30	30
g	Unbolt from mounts	30	30
h	Remove contamination controls	15	15
i	Remove, wrap, send to waste processing area	60	60
	Totals (Activity/Critical)	355	255

Duration adjustment(s):	
+ Respiratory protection adjustment (50% of critical duration)	128
+ Radiation/ALARA adjustment (37.1% of critical duration)	95
Adjusted work duration	478
+ Protective clothing adjustment (30% of adjusted duration)	143
Productive work duration	621
+ Work break adjustment (8.33 % of productive duration)	52
Total work duration (minutes)	673

***** Total duration = 11.217 hr *****

* alpha designators indicate activities that can be performed in parallel

APPENDIX A
(continued)

3. LABOR REQUIRED

Crew	Number	Duration (hours)	Rate ($/hr)	Cost
Laborers	3.00	11.217	$32.90	$1,107.12
Craftsmen	2.00	11.217	$39.29	$881.43
Foreman	1.00	11.217	$42.01	$471.23
General Foreman	0.25	11.217	$44.74	$125.46
Fire Watch	0.05	11.217	$32.90	$18.45
Health Physics Technician	1.00	11.217	$44.96	$504.32
Total Labor Cost				$3,108.01

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs	none
Consumables/Materials Costs	
-Universal Sorbent 50 @ $0.63 sq. ft. {1}	$31.50
-Tarpaulins (oil resistant/fire retardant) 50 @ $0.43/sq. ft. {2}	$21.50
-Gas torch consumables 1 @ $21.02/hr. x 1 hr. {3}	$21.02
Subtotal cost of equipment and materials	$74.02
Overhead & profit on equipment and materials @ 16.00 %	$11.84
Total costs, equipment & material	$85.86

TOTAL COST:

Removal of contaminated heat exchanger <3000 pounds:	**$3,193.87**
Total labor cost:	$3,108.01
Total equipment/material costs:	$85.86
Total craft labor man-hours required per unit:	81.88

5. NOTES AND REFERENCES

- Work difficulty factors were developed in conjunction with the Atomic Industrial Forum's (now NEI) program to standardize nuclear decommissioning cost estimates and are delineated in Volume 1, Chapter 5 of the "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

- References for equipment & consumables costs:

    1. www.mcmaster.com online catalog, McMaster Carr Spill Control (7193T88)
    2. R.S. Means (2016) Division 01 56, Section 13.60-0600, page 22
    3. R.S. Means (2016) Division 01 54 33, Section 40-6360, page 710

- Material and consumable costs were adjusted using the regional indices for Columbia, South Carolina

APPENDIX B

UNIT COST FACTOR LISTING
(DECON: Power Block Structures Only)

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of clean instrument and sampling tubing, $/linear foot	0.35
Removal of clean pipe 0.25 to 2 inches diameter, $/linear foot	3.85
Removal of clean pipe >2 to 4 inches diameter, $/linear foot	5.45
Removal of clean pipe >4 to 8 inches diameter, $/linear foot	10.39
Removal of clean pipe >8 to 14 inches diameter, $/linear foot	20.15
Removal of clean pipe >14 to 20 inches diameter, $/linear foot	26.38
Removal of clean pipe >20 to 36 inches diameter, $/linear foot	38.76
Removal of clean pipe >36 inches diameter, $/linear foot	45.98
Removal of clean valve >2 to 4 inches	69.62
Removal of clean valve >4 to 8 inches	103.91
Removal of clean valve >8 to 14 inches	201.50
Removal of clean valve >14 to 20 inches	263.77
Removal of clean valve >20 to 36 inches	387.63
Removal of clean valve >36 inches	459.77
Removal of clean pipe hanger for small bore piping	26.82
Removal of clean pipe hanger for large bore piping	91.56
Removal of clean pump, <300 pound	179.10
Removal of clean pump, 300-1000 pound	485.27
Removal of clean pump, 1000-10,000 pound	1,905.93
Removal of clean pump, >10,000 pound	3,699.61
Removal of clean pump motor, 300-1000 pound	199.53
Removal of clean pump motor, 1000-10,000 pound	786.93
Removal of clean pump motor, >10,000 pound	1,770.59
Removal of clean heat exchanger <3000 pound	1,030.16
Removal of clean heat exchanger >3000 pound	2,612.09
Removal of clean feedwater heater/deaerator	7,315.92
Removal of clean moisture separator/reheater	14,976.11
Removal of clean tank, <300 gallons	229.92
Removal of clean tank, 300-3000 gallon	717.71
Removal of clean tank, >3000 gallons, $/square foot surface area	6.01

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of clean electrical equipment, <300 pound	94.42
Removal of clean electrical equipment, 300-1000 pound	324.86
Removal of clean electrical equipment, 1000-10,000 pound	649.71
Removal of clean electrical equipment, >10,000 pound	1,541.08
Removal of clean electrical transformer < 30 tons	1,070.27
Removal of clean electrical transformer > 30 tons	3,082.18
Removal of clean standby diesel generator, <100 kW	1,093.18
Removal of clean standby diesel generator, 100 kW to 1 MW	2,440.04
Removal of clean standby diesel generator, >1 MW	5,051.40
Removal of clean electrical cable tray, $/linear foot	9.07
Removal of clean electrical conduit, $/linear foot	3.98
Removal of clean mechanical equipment, <300 pound	94.42
Removal of clean mechanical equipment, 300-1000 pound	324.86
Removal of clean mechanical equipment, 1000-10,000 pound	649.71
Removal of clean mechanical equipment, >10,000 pound	1,541.08
Removal of clean HVAC equipment, <300 pound	114.17
Removal of clean HVAC equipment, 300-1000 pound	390.34
Removal of clean HVAC equipment, 1000-10,000 pound	777.95
Removal of clean HVAC equipment, >10,000 pound	1,541.08
Removal of clean HVAC ductwork, $/pound	0.37
Removal of contaminated instrument and sampling tubing, $/linear foot	1.18
Removal of contaminated pipe 0.25 to 2 inches diameter, $/linear foot	18.61
Removal of contaminated pipe >2 to 4 inches diameter, $/linear foot	29.96
Removal of contaminated pipe >4 to 8 inches diameter, $/linear foot	46.48
Removal of contaminated pipe >8 to 14 inches diameter, $/linear foot	89.94
Removal of contaminated pipe >14 to 20 inches diameter, $/linear foot	107.25
Removal of contaminated pipe >20 to 36 inches diameter, $/linear foot	146.52
Removal of contaminated pipe >36 inches diameter, $/linear foot	172.20
Removal of contaminated valve >2 to 4 inches	346.60
Removal of contaminated valve >4 to 8 inches	409.83

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated valve >8 to 14 inches	837.95
Removal of contaminated valve >14 to 20 inches	1,060.17
Removal of contaminated valve >20 to 36 inches	1,403.70
Removal of contaminated valve >36 inches	1,660.51
Removal of contaminated pipe hanger for small bore piping	117.24
Removal of contaminated pipe hanger for large bore piping	387.22
Removal of contaminated pump, <300 pound	737.22
Removal of contaminated pump, 300-1000 pound	1,665.99
Removal of contaminated pump, 1000-10,000 pound	5,235.15
Removal of contaminated pump, >10,000 pound	12,748.90
Removal of contaminated pump motor, 300-1000 pound	734.71
Removal of contaminated pump motor, 1000-10,000 pound	2,156.57
Removal of contaminated pump motor, >10,000 pound	4,842.02
Removal of contaminated heat exchanger <3000 pound	3,193.87
Removal of contaminated heat exchanger >3000 pound	9,351.53
Removal of contaminated tank, <300 gallons	1,231.64
Removal of contaminated tank, >300 gallons, $/square foot	22.88
Removal of contaminated electrical equipment, <300 pound	554.24
Removal of contaminated electrical equipment, 300-1000 pound	1,331.04
Removal of contaminated electrical equipment, 1000-10,000 pound	2,565.12
Removal of contaminated electrical equipment, >10,000 pound	5,019.34
Removal of contaminated electrical cable tray, $/linear foot	26.94
Removal of contaminated electrical conduit, $/linear foot	13.98
Removal of contaminated mechanical equipment, <300 pound	616.07
Removal of contaminated mechanical equipment, 300-1000 pound	1,467.94
Removal of contaminated mechanical equipment, 1000-10,000 pound	2,824.24
Removal of contaminated mechanical equipment, >10,000 pound	5,019.34
Removal of contaminated HVAC equipment, <300 pound	616.07
Removal of contaminated HVAC equipment, 300-1000 pound	1,467.94
Removal of contaminated HVAC equipment, 1000-10,000 pound	2,824.24

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated HVAC equipment, >10,000 pound	5,019.34
Removal of contaminated HVAC ductwork, $/pound	1.80
Removal/plasma arc cut of contaminated thin metal components, $/linear in.	2.89
Additional decontamination of surface by washing, $/square foot	6.34
Additional decontamination of surfaces by hydrolasing, $/square foot	24.88
Decontamination rig hook up and flush, $/ 250 foot length	5,155.11
Chemical flush of components/systems, $/gallon	20.76
Removal of clean standard reinforced concrete, $/cubic yard	67.88
Removal of grade slab concrete, $/cubic yard	77.17
Removal of clean concrete floors, $/cubic yard	323.81
Removal of sections of clean concrete floors, $/cubic yard	925.60
Removal of clean heavily rein concrete w/#9 rebar, $/cubic yard	97.85
Removal of contaminated heavily rein concrete w/#9 rebar, $/cubic yard	1,763.94
Removal of clean heavily rein concrete w/#18 rebar, $/cubic yard	132.57
Removal of contaminated heavily rein concrete w/#18 rebar, $/cubic yard	2,330.78
Removal heavily rein concrete w/#18 rebar & steel embedments, $/cubic yard	389.13
Removal of below-grade suspended floors, $/cubic yard	185.78
Removal of clean monolithic concrete structures, $/cubic yard	750.25
Removal of contaminated monolithic concrete structures, $/cubic yard	1,749.26
Removal of clean foundation concrete, $/cubic yard	593.88
Removal of contaminated foundation concrete, $/cubic yard	1,630.76
Explosive demolition of bulk concrete, $/cubic yard	41.13
Removal of clean hollow masonry block wall, $/cubic yard	23.32
Removal of contaminated hollow masonry block wall, $/cubic yard	60.63
Removal of clean solid masonry block wall, $/cubic yard	23.32
Removal of contaminated solid masonry block wall, $/cubic yard	60.63
Backfill of below-grade voids, $/cubic yard	33.75
Removal of subterranean tunnels/voids, $/linear foot	97.02
Placement of concrete for below-grade voids, $/cubic yard	133.86
Excavation of clean material, $/cubic yard	2.87

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Excavation of contaminated material, $/cubic yard	36.12
Removal of clean concrete rubble (tipping fee included), $/cubic yard	24.01
Removal of contaminated concrete rubble, $/cubic yard	23.93
Removal of building by volume, $/cubic foot	0.27
Removal of clean building metal siding, $/square foot	1.18
Removal of contaminated building metal siding, $/square foot	3.96
Removal of standard asphalt roofing, $/square foot	1.66
Removal of transite panels, $/square foot	1.73
Scarifying contaminated concrete surfaces (drill & spall), $/square foot	10.91
Scabbling contaminated concrete floors, $/square foot	6.52
Scabbling contaminated concrete walls, $/square foot	16.92
Scabbling contaminated ceilings, $/square foot	57.77
Scabbling structural steel, $/square foot	5.13
Removal of clean overhead crane/monorail < 10 ton capacity	448.77
Removal of contaminated overhead crane/monorail < 10 ton capacity	1,336.18
Removal of clean overhead crane/monorail >10-50 ton capacity	1,077.00
Removal of contaminated overhead crane/monorail >10-50 ton capacity	3,206.26
Removal of polar crane > 50 ton capacity	4,495.62
Removal of gantry crane > 50 ton capacity	19,263.56
Removal of structural steel, $/pound	0.16
Removal of clean steel floor grating, $/square foot	3.40
Removal of contaminated steel floor grating, $/square foot	10.17
Removal of clean free standing steel liner, $/square foot	9.01
Removal of contaminated free standing steel liner, $/square foot	26.61
Removal of clean concrete-anchored steel liner, $/square foot	4.51
Removal of contaminated concrete-anchored steel liner, $/square foot	31.05
Placement of scaffolding in clean areas, $/square foot	15.84
Placement of scaffolding in contaminated areas, $/square foot	23.83
Landscaping with topsoil, $/acre	23,159.87
Cost of CPC B-88 LSA box & preparation for use	2,048.32

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Cost of CPC B-25 LSA box & preparation for use	1,926.41
Cost of CPC B-12V 12 gauge LSA box & preparation for use	1,522.93
Cost of CPC B-144 LSA box & preparation for use	10,582.75
Cost of LSA drum & preparation for use	189.38
Cost of cask liner for CNSI 8 120A cask (resins)	12,206.78
Cost of cask liner for CNSI 8 120A cask (filters)	8,695.42
Decontamination of surfaces with vacuuming, $/square foot	0.68

APPENDIX C

DETAILED COST ANALYSIS

DECON

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	269	40	310	310	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	1,010	151	1,161	1,161	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	417	63	480	480	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Perform Site-Specific Cost Study	-	-	-	-	-	-	673	101	774	774	-	-	-	-	-	-	-	-	-	5,000
1a.1.15	Prepare/submit License Termination Plan	-	-	-	-	-	-	551	83	634	634	-	-	-	-	-	-	-	-	-	4,096
1a.1.16	Receive NRC approval of termination plan									a											
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	662	99	762	686	-	76	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	561	84	645	581	-	65	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	67	10	77	77	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	956	143	1,099	1,099	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	875	131	1,006	1,006	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	67	10	77	77	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	420	63	483	483	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	215	32	248	124	-	124	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	54	8	62	-	-	62	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	54	8	62	-	-	62	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	420	63	483	242	-	242	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	121	18	139	70	-	70	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	5,093	764	5,857	5,157	-	700	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	323	48	372	372	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,200	480	3,680	3,680	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	188	28	217	217	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	166	25	190	190	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	15,429	2,314	17,744	17,044	-	700	-	-	-	-	-	-	-	73,753
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	3,275	327	3,602	3,602	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	13,564	1,356	14,921	14,921	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	643	643	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	707	-	-	-	-	-	106	813	813	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	2	-	25	-	8	48	48	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,876	281	2,158	2,158	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,142	114	1,256	1,256	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,009	101	1,110	-	1,110	-	-	-	-	-	-	-	-	-
1a.4.9	Non-Labor Overhead	-	-	-	-	-	-	1,311	197	1,508	1,508	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	801	120	921	-	921	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	100	15	115	-	115	-	-	-	-	-	-	-	-	-
1a.4.12	Corporate A&G	-	-	-	-	-	-	2,804	421	3,224	3,224	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	12,906	1,936	14,842	14,842	-	-	-	-	-	-	-	-	-	381,686
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	24,505	3,676	28,180	28,180	-	-	-	-	-	-	-	-	-	423,400
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,221	13	2	-	25	63,293	8,787	73,342	71,195	2,146	-	-	610	-	-	-	12,190	20	805,086
1a.0	TOTAL PERIOD 1a COST	-	1,221	13	2	-	25	78,723	11,101	91,085	88,239	2,146	700	-	610	-	-	-	12,190	20	878,838

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	637	96	733	660	-	73	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	337	50	387	387	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	182	27	209	52	-	157	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	162	24	186	93	-	93	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	61	9	70	70	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	162	24	186	186	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	135	20	155	77	-	77	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	210	32	242	-	-	242	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	210	32	242	-	-	242	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	368	55	423	380	-	42	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	368	55	423	380	-	42	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	4,476	671	5,147	4,179	-	968	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	597	-	-	-	-	-	-	299	896	896	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	597	-	-	-	-	-	4,476	970	6,043	5,075	-	968	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,358	1,704	13,062	13,062	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	3,640	1,092	4,733	4,733	-	-	-	-	-	-	-	-	22,800	8,812
1b.2	Subtotal Period 1b Additional Costs	-	-	-	-	-	-	14,998	2,796	17,794	17,794	-	-	-	-	-	-	-	-	22,800	8,812
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	946	-	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	53	-	34	30	-	208	-	86	412	412	-	-	-	334	-	-	-	20,064	65	-
1b.3.4	Process decommissioning chemical flush waste	2	-	62	123	-	1,489	-	398	2,074	2,074	-	-	-	-	638	-	-	67,944	119	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,600	-	-	-	-	-	-	240	1,840	1,840	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	985	148	1,133	-	1,133	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,601	1,202	96	154	-	1,697	2,308	1,393	9,450	8,316	1,133	-	-	334	638	-	-	88,008	185	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	29	-	-	-	-	-	-	7	36	36	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,633	163	1,796	1,796	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	288	-	-	-	-	-	72	360	360	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	352	-	-	-	-	-	53	405	405	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	1	-	15	-	5	28	28	-	-	-	356	-	-	-	7,122	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,871	281	2,152	2,152	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	335	33	368	368	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	503	50	553	-	553	-	-	-	-	-	-	-	-	-
1b.4.10	Non-Labor Overhead	-	-	-	-	-	-	657	99	755	755	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	399	60	459	-	459	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	50	8	58	-	58	-	-	-	-	-	-	-	-	-
1b.4.13	Corporate A&G	-	-	-	-	-	-	1,405	211	1,616	1,616	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	6,435	965	7,401	7,401	-	-	-	-	-	-	-	-	-	190,320
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,726	859	6,585	6,585	-	-	-	-	-	-	-	-	-	63,440
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	12,280	1,842	14,122	14,122	-	-	-	-	-	-	-	-	-	212,160
1b.4	Subtotal Period 1b Period-Dependent Costs	29	640	8	1	-	15	31,295	4,707	36,694	35,624	1,070	-	-	356	-	-	-	7,122	12	465,920
1b.0	TOTAL PERIOD 1b COST	3,227	1,842	104	155	-	1,711	53,076	9,866	69,981	66,809	2,203	968	-	690	638	-	-	95,130	24,063	507,975
PERIOD 1 TOTALS		3,227	3,063	117	157	-	1,736	131,799	20,967	161,066	155,049	4,350	1,668	-	1,300	638	-	-	107,320	24,083	1,386,813

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	60	57	12	5	-	193	-	94	421	421	-	-	-	595	-	-	-	67,988	2,822	-
2a.1.1.2	Pressurizer Relief Tank	18	16	6	2	-	84	-	35	161	161	-	-	-	265	-	-	-	29,424	863	-
2a.1.1.3	Reactor Coolant Pumps & Motors	46	58	135	170	-	245	-	138	792	792	-	-	-	3,322	-	-	-	605,445	3,043	100
2a.1.1.4	Pressurizer	29	39	577	160	-	211	-	159	1,174	1,174	-	-	-	2,862	-	-	-	228,995	2,367	1,875
2a.1.1.5	Steam Generators	203	5,645	2,755	1,639	-	2,062	-	2,549	14,853	14,853	-	-	-	27,948	-	-	-	2,412,202	9,325	3,500
2a.1.1.6	Retired Steam Generator Units	-	-	2,755	1,639	-	2,062	-	1,037	7,493	7,493	-	-	-	27,948	-	-	-	2,250,000	-	2,250
2a.1.1.7	CRDMs/ICIs/Service Structure Removal	104	187	211	17	-	382	-	218	1,120	1,120	-	-	-	3,538	-	-	-	134,644	7,232	-
2a.1.1.8	Reactor Vessel Internals	68	5,312	7,950	409	-	5,484	300	8,895	28,419	28,419	-	-	-	1,252	656	281	-	220,785	25,740	1,188
2a.1.1.9	Reactor Vessel	66	7,871	1,907	251	-	10,318	300	11,680	32,393	32,393	-	-	-	7,526	-	-	-	768,730	25,740	1,188
2a.1.1	Totals	594	19,186	16,308	4,293	-	21,041	600	24,805	86,827	86,827	-	-	-	75,255	656	281	-	6,718,212	77,132	10,101
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	263	158	29	469	397	-	255	1,572	1,572	-	-	5,060	2,113	-	-	-	367,369	6,757	-
2a.1.3	Main Condensers	-	842	184	34	547	463	-	432	2,502	2,502	-	-	5,901	2,464	-	-	-	428,414	21,496	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	377	-	-	-	-	-	57	434	434	-	-	-	-	-	-	-	-	3,705	-
2a.1.4.2	Auxiliary	-	164	-	-	-	-	-	25	189	189	-	-	-	-	-	-	-	-	1,189	-
2a.1.4.3	Fuel Handling	-	57	-	-	-	-	-	9	66	66	-	-	-	-	-	-	-	-	648	-
2a.1.4	Totals	-	599	-	-	-	-	-	90	689	689	-	-	-	-	-	-	-	-	5,542	-
Disposal of Plant Systems																					
2a.1.5.1	Aux Boiler Steam & Reheat	-	35	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	938	-
2a.1.5.2	Aux Boiler Steam & Reheat (RCA)	-	83	4	9	225	-	-	56	379	379	-	-	2,692	-	-	-	-	109,340	1,764	-
2a.1.5.3	Auxiliary Coolant	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	665	-
2a.1.5.4	Breathing Air (RCA)	-	24	0	0	11	-	-	8	43	43	-	-	131	-	-	-	-	5,326	451	-
2a.1.5.5	Carbon Dioxide - Gen Gas & Vents	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	140	-
2a.1.5.6	Chemical Cleaning	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	244	-
2a.1.5.7	Chilled Water	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	2,963	-
2a.1.5.8	Component Cooling	-	72	-	-	-	-	-	11	83	-	-	83	-	-	-	-	-	-	1,927	-
2a.1.5.9	Condensate	-	214	-	-	-	-	-	32	246	-	-	246	-	-	-	-	-	-	5,692	-
2a.1.5.10	Condensate Demin	-	35	-	-	-	-	-	5	40	-	-	40	-	-	-	-	-	-	923	-
2a.1.5.11	Condenser Air Removal	-	85	-	-	-	-	-	13	97	-	-	97	-	-	-	-	-	-	2,274	-
2a.1.5.12	Condenser Cleaning	-	12	-	-	-	-	-	2	14	-	-	14	-	-	-	-	-	-	317	-
2a.1.5.13	Demineralized Water	-	39	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	1,003	-
2a.1.5.14	Emergency Feedwater	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	654	-
2a.1.5.15	Emergency Feedwater (RCA)	-	43	1	3	72	-	-	22	141	141	-	-	855	-	-	-	-	34,715	984	-
2a.1.5.16	Extraction Steam	-	70	-	-	-	-	-	10	80	-	-	80	-	-	-	-	-	-	1,882	-
2a.1.5.17	Feedwater	-	299	-	-	-	-	-	45	344	-	-	344	-	-	-	-	-	-	8,000	-
2a.1.5.18	Feedwater (RCA)	-	51	3	6	149	-	-	36	245	245	-	-	1,782	-	-	-	-	72,373	1,161	-
2a.1.5.19	Filtered & Raw Water Treatment	-	159	-	-	-	-	-	24	183	-	-	183	-	-	-	-	-	-	4,169	-
2a.1.5.20	Gland Sealing Steam	-	28	-	-	-	-	-	4	32	-	-	32	-	-	-	-	-	-	773	-
2a.1.5.21	Heater Drains & Vents	-	160	-	-	-	-	-	24	184	-	-	184	-	-	-	-	-	-	4,322	-
2a.1.5.22	HVAC - Control Bldg	-	34	-	-	-	-	-	5	39	-	-	39	-	-	-	-	-	-	954	-
2a.1.5.23	HVAC - Intermediate	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	823	-
2a.1.5.24	HVAC - Misc Bldgs	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	1,436	-
2a.1.5.25	HVAC - Turbine	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,876	-
2a.1.5.26	Hydrogen	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	106	-
2a.1.5.27	Hydrogen - Plant (NSSS H & O2)	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	206	-
2a.1.5.28	Instrument Air	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,040	-
2a.1.5.29	Lube Oil	-	53	-	-	-	-	-	8	60	-	-	60	-	-	-	-	-	-	1,390	-
2a.1.5.30	Main Steam	-	154	-	-	-	-	-	23	177	-	-	177	-	-	-	-	-	-	4,133	-
2a.1.5.31	Main Steam (RCA)	-	65	3	5	131	-	-	37	241	241	-	-	1,563	-	-	-	-	63,494	1,396	-
2a.1.5.32	Main Steam Dump	-	23	-	-	-	-	-	4	27	-	-	27	-	-	-	-	-	-	639	-
2a.1.5.33	Nitrogen & Oxygen	-	16	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	404	-
2a.1.5.34	Nitrogen & Oxygen (RCA)	-	56	1	1	34	-	-	19	112	112	-	-	404	-	-	-	-	16,411	1,055	-
2a.1.5.35	Non-Nuclear Plant Drains	-	56	-	-	-	-	-	8	64	-	-	64	-	-	-	-	-	-	1,515	-
2a.1.5.36	Nuclear Blowdown Processing	-	247	18	10	165	122	-	120	682	682	-	-	1,968	648	-	-	-	122,732	5,654	-
2a.1.5.37	PASS - H2 Removal	-	35	3	2	30	17	-	18	104	104	-	-	362	89	-	-	-	20,633	838	-
2a.1.5.38	Reactor Coolant	-	218	150	27	-	1,113	-	352	1,860	1,860	-	-	-	5,914	-	-	-	391,758	5,330	-
2a.1.5.39	Reheat Steam	-	82	-	-	-	-	-	12	95	-	-	95	-	-	-	-	-	-	2,195	-
2a.1.5.40	RX Leak Rate Testing	-	11	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	295	-

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2a.1.5.41	Safety Injection	-	515	91	17	-	683	-	311	1,618	1,618	-	-	-	3,667	-	-	-	240,663	11,776	-
2a.1.5.42	Steam Gen Blowdown	-	42	-	-	-	-	-	6	48	-	-	48	-	-	-	-	-	-	1,059	-
2a.1.5.43	Steam Gen Blowdown (RCA)	-	24	0	0	9	-	-	7	41	41	-	-	109	-	-	-	-	4,425	534	-
2a.1.5.44	TB Closed Cycle Cooling	-	56	-	-	-	-	-	8	64	-	-	64	-	-	-	-	-	-	1,492	-
2a.1.5.45	TB Cycle Chem Feed	-	81	-	-	-	-	-	12	93	-	-	93	-	-	-	-	-	-	2,088	-
2a.1.5.46	TB Cycle Sampling	-	37	-	-	-	-	-	6	43	-	-	43	-	-	-	-	-	-	962	-
2a.1.5.47	Turbine Systems	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	657	-
2a.1.5	Totals	-	3,612	275	82	825	1,935	-	1,325	8,053	5,465	-	2,588	9,867	10,319	-	-	-	1,081,869	91,099	-
2a.1.6	Scaffolding in support of decommissioning	-	1,256	26	5	102	18	-	337	1,744	1,744	-	-	1,101	97	-	-	-	55,984	34,818	-
2a.1	Subtotal Period 2a Activity Costs	594	25,758	16,951	4,443	1,944	23,853	600	27,245	101,387	98,799	-	2,588	21,929	90,249	656	281	-	8,651,847	236,844	10,101
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,290	387	1,677	1,677	-	-	-	-	-	-	-	-	28,702	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	1,290	387	1,677	1,677	-	-	-	-	-	-	-	-	28,702	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	100	-	65	58	-	398	-	165	786	786	-	-	-	640	-	-	-	38,396	125	-
2a.3.3	Small tool allowance	-	199	-	-	-	-	-	30	229	206	-	23	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	14,620	2,193	16,813	-	16,813	-	-	-	-	-	-	-	-	-
2a.3.5	On-site survey and release of 27.16 tons clean metallic waste	-	-	-	-	-	-	47	5	51	51	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	100	199	65	58	-	398	14,667	2,392	17,879	1,043	16,813	23	-	640	-	-	-	38,396	125	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	80	-	-	-	-	-	-	20	100	100	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	837	84	921	921	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,993	-	-	-	-	-	498	2,492	2,492	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,557	-	-	-	-	-	534	4,091	4,091	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	91	16	-	174	-	55	337	337	-	-	-	4,276	-	-	-	85,525	139	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	2,461	369	2,831	2,831	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	841	84	925	925	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	566	57	622	-	622	-	-	-	-	-	-	-	-	-
2a.4.10	Non-Labor Overhead	-	-	-	-	-	-	1,319	198	1,517	1,517	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,106	166	1,272	-	1,272	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	138	21	159	-	159	-	-	-	-	-	-	-	-	-
2a.4.13	Corporate A&G	-	-	-	-	-	-	2,698	405	3,103	3,103	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	11,028	1,654	12,683	12,683	-	-	-	-	-	-	-	-	-	308,160
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	18,664	2,800	21,464	21,464	-	-	-	-	-	-	-	-	-	218,880
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	23,907	3,586	27,493	27,493	-	-	-	-	-	-	-	-	-	407,520
2a.4	Subtotal Period 2a Period-Dependent Costs	80	5,551	91	16	-	174	63,568	10,530	80,011	77,958	2,053	-	-	4,276	-	-	-	85,525	139	934,560
2a.0	TOTAL PERIOD 2a COST	773	31,508	17,107	4,517	1,944	24,426	80,125	40,554	200,954	179,477	18,866	2,611	21,929	95,165	656	281	-	8,775,768	265,810	944,661
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	Auxiliary Coolant (RCA)	-	12	0	0	11	-	-	5	28	28	-	-	128	-	-	-	-	5,207	257	-
2b.1.1.2	Chemical Cleaning (RCA)	-	111	47	10	-	424	-	140	733	733	-	-	-	2,260	-	-	-	149,370	2,481	-
2b.1.1.3	Chilled Water (RCA)	-	67	1	2	44	-	-	24	138	138	-	-	530	-	-	-	-	21,542	1,333	-
2b.1.1.4	Circulating Water	-	221	-	-	-	-	-	33	254	-	-	254	-	-	-	-	-	-	5,970	-
2b.1.1.5	Component Cooling (RCA)	-	429	16	35	831	-	-	239	1,551	1,551	-	-	9,938	-	-	-	-	403,572	9,324	-
2b.1.1.6	CVCS/Boron Recycle/Thermal Regen	-	981	176	35	-	1,442	-	628	3,262	3,262	-	-	-	7,761	-	-	-	507,608	22,632	-
2b.1.1.7	Diesel Generator Services	-	97	-	-	-	-	-	14	111	-	-	111	-	-	-	-	-	-	2,525	-
2b.1.1.8	Electrical	-	2,690	-	-	-	-	-	403	3,093	-	-	3,093	-	-	-	-	-	-	70,753	-
2b.1.1.9	Electrical - RCA	-	3,057	440	97	-	3,977	-	1,817	9,389	9,389	-	-	-	21,188	-	-	-	1,400,488	64,407	-
2b.1.1.10	Excess Liquid Waste	-	80	10	2	-	79	-	41	213	213	-	-	-	422	-	-	-	27,915	1,762	-
2b.1.1.11	Fire Service & Sprinkler	-	319	-	-	-	-	-	48	367	-	-	367	-	-	-	-	-	-	8,380	-
2b.1.1.12	Fuel Handling Oil	-	75	-	-	-	-	-	11	87	-	-	87	-	-	-	-	-	-	1,958	-
2b.1.1.13	HVAC - Auxiliary	-	338	12	16	359	39	-	152	916	916	-	-	4,291	210	-	-	-	188,151	7,471	-
2b.1.1.14	HVAC - Reactor	-	344	11	17	374	36	-	155	937	937	-	-	4,473	194	-	-	-	194,459	7,540	-
2b.1.1.15	Industrial Cooling Water (RCA)	-	150	5	11	257	-	-	78	501	501	-	-	3,073	-	-	-	-	124,806	3,370	-
2b.1.1.16	Instrument Air (RCA)	-	176	4	8	180	-	-	73	441	441	-	-	2,157	-	-	-	-	87,616	3,688	-

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.17	Liquid Effluents	-	89	-	-	-	-	-	13	102	-	-	102	-	-	-	-	-	-	2,437	-
2b.1.1.18	Misc Yard Pipe	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	127	-
2b.1.1.19	Non-Nuclear Plant Drains (RCA)	-	19	0	1	19	-	-	8	46	46	-	-	226	-	-	-	-	9,166	389	-
2b.1.1.20	Nuclear Plant Drains	-	210	22	4	-	149	-	92	477	477	-	-	-	795	-	-	-	52,561	4,649	-
2b.1.1.21	Nuclear Sampling	-	71	8	1	-	55	-	32	167	167	-	-	-	290	-	-	-	19,231	1,669	-
2b.1.1.22	Radwaste Gas Handling	-	288	62	12	-	505	-	206	1,074	1,074	-	-	-	2,737	-	-	-	177,907	6,598	-
2b.1.1.23	Residual Heat Removal	-	299	61	12	-	509	-	210	1,092	1,092	-	-	-	2,706	-	-	-	179,055	7,128	-
2b.1.1.24	RX Building Spray	-	382	25	16	288	173	-	187	1,071	1,071	-	-	3,446	919	-	-	-	200,690	8,874	-
2b.1.1.25	RX Makeup Water	-	196	36	7	-	305	-	130	674	674	-	-	-	1,668	-	-	-	107,299	4,620	-
2b.1.1.26	Sanitary & Industrial Waste	-	134	-	-	-	-	-	20	154	-	-	154	-	-	-	-	-	-	3,665	-
2b.1.1.27	Service Air	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	1,219	-
2b.1.1.28	Service Air (RCA)	-	78	1	2	43	-	-	26	150	150	-	-	514	-	-	-	-	20,870	1,431	-
2b.1.1.29	Service Water	-	324	-	-	-	-	-	49	373	-	-	373	-	-	-	-	-	-	8,722	-
2b.1.1.30	Service Water (RCA)	-	196	13	26	631	-	-	149	1,015	1,015	-	-	7,548	-	-	-	-	306,527	4,487	-
2b.1.1	Totals	-	11,484	950	315	3,039	7,693	-	4,992	28,473	23,874	-	4,599	36,324	41,150	-	-	-	4,184,038	269,864	-
2b.1.2	Scaffolding in support of decommissioning	-	1,570	32	6	128	23	-	422	2,180	2,180	-	-	1,377	121	-	-	-	69,980	43,523	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,004	1,271	63	175	227	1,806	-	1,338	5,883	5,883	-	-	2,712	22,357	-	-	-	1,886,954	49,718	-
2b.1.3.2	Auxiliary	772	375	17	46	106	354	-	593	2,262	2,262	-	-	1,267	5,098	-	-	-	491,122	25,238	-
2b.1.3.3	Contaminated Tool Warehouse	32	14	1	2	-	15	-	24	88	88	-	-	-	225	-	-	-	19,500	997	-
2b.1.3.4	Control Complex	91	30	1	4	5	31	-	62	224	224	-	-	64	445	-	-	-	41,143	2,686	-
2b.1.3.5	Hot Machine Shop	23	13	1	2	6	11	-	19	74	74	-	-	76	164	-	-	-	17,013	785	-
2b.1.3.6	Intermediate	126	31	1	3	13	22	-	79	274	274	-	-	152	311	-	-	-	33,003	3,581	-
2b.1.3.7	Old Steam Generator Recycle Facility	32	13	1	2	-	15	-	23	87	87	-	-	-	222	-	-	-	19,266	985	-
2b.1.3.8	Reactor Building Retaining Wall	0	2	0	0	1	2	-	1	7	7	-	-	13	28	-	-	-	2,965	47	-
2b.1.3	Totals	2,080	1,748	84	233	358	2,256	-	2,138	8,899	8,899	-	-	4,285	28,851	-	-	-	2,510,966	84,037	-
2b.1	Subtotal Period 2b Activity Costs	2,080	14,803	1,066	554	3,525	9,972	-	7,552	39,552	34,953	-	4,599	41,986	70,122	-	-	-	6,764,984	397,424	-
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,984	595	2,579	2,579	-	-	-	-	-	-	-	-	44,135	-
2b.2.2	Excavation of Underground Services	-	823	-	-	-	-	752	236	1,811	1,811	-	-	-	-	-	-	-	-	13,000	-
2b.2	Subtotal Period 2b Additional Costs	-	823	-	-	-	-	2,736	832	4,391	4,391	-	-	-	-	-	-	-	-	57,135	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	103	-	69	61	-	420	-	172	824	824	-	-	-	674	-	-	-	40,469	132	-
2b.3.3	Small tool allowance	-	258	-	-	-	-	-	39	297	297	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	22,522	3,378	25,900	-	25,900	-	-	-	-	-	-	-	-	-
2b.3.5	On-site survey and release of 1.13 tons clean metallic waste	-	-	-	-	-	-	2	0	2	2	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	103	258	69	61	-	420	22,524	3,589	27,023	1,123	25,900	-	-	674	-	-	-	40,469	132	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,235	-	-	-	-	-	-	309	1,544	1,544	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,288	129	1,416	1,416	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	3,270	-	-	-	-	-	817	4,087	4,087	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	5,617	-	-	-	-	-	843	6,460	6,460	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	120	21	-	228	-	72	442	442	-	-	-	5,600	-	-	-	111,996	183	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	2,988	448	3,436	3,436	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,294	129	1,423	1,423	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	870	87	957	-	957	-	-	-	-	-	-	-	-	-
2b.4.10	Non-Labor Overhead	-	-	-	-	-	-	1,943	291	2,234	2,234	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,701	255	1,956	-	1,956	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	514	77	591	591	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	213	32	245	-	245	-	-	-	-	-	-	-	-	-
2b.4.14	Corporate A&G	-	-	-	-	-	-	3,973	596	4,569	4,569	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	16,958	2,544	19,502	19,502	-	-	-	-	-	-	-	-	-	473,857
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,595	4,139	31,735	31,735	-	-	-	-	-	-	-	-	-	323,286
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	35,280	5,292	40,571	40,571	-	-	-	-	-	-	-	-	-	600,071
2b.4	Subtotal Period 2b Period-Dependent Costs	1,235	8,887	120	21	-	228	94,616	16,061	121,169	118,011	3,157	-	-	5,600	-	-	-	111,996	183	1,397,214
2b.0	TOTAL PERIOD 2b COST	3,419	24,771	1,254	636	3,525	10,620	119,876	28,034	192,135	158,478	29,057	4,599	41,986	76,397	-	-	-	6,917,449	454,873	1,397,214

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	20,327	3,049	23,376	-	23,376	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	20,327	3,049	23,376	-	23,376	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	1,214	121	1,336	1,336	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	505	-	-	-	-	-	126	632	632	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	21	4	-	39	-	12	76	76	-	-	-	961	-	-	-	19,227	31	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	2,818	423	3,241	3,241	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	1,066	107	1,172	1,172	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	821	82	903	-	903	-	-	-	-	-	-	-	-	-
2c.4.8	Non-Labor Overhead	-	-	-	-	-	-	1,292	194	1,485	1,485	-	-	-	-	-	-	-	-	-	-
2c.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	1,604	241	1,845	-	1,845	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	201	30	231	-	231	-	-	-	-	-	-	-	-	-
2c.4.11	Corporate A&G	-	-	-	-	-	-	2,641	396	3,038	3,038	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	13,704	2,056	15,760	7,880	7,880	-	-	-	-	-	-	-	-	363,411
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	24,678	3,702	28,380	14,190	14,190	-	-	-	-	-	-	-	-	398,917
2c.4	Subtotal Period 2c Period-Dependent Costs	-	505	21	4	-	39	50,039	7,490	58,098	33,050	25,048	-	-	961	-	-	-	19,227	31	762,329
2c.0	TOTAL PERIOD 2c COST	-	505	21	4	-	39	70,366	10,539	81,474	33,050	48,424	-	-	961	-	-	-	19,227	31	762,329
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	479	44	210	22	-	894	-	498	2,147	2,147	-	-	-	4,761	-	-	-	314,710	1,311	-
Disposal of Plant Systems																					
2d.1.2.1	Demineralized Water (RCA)	-	137	2	3	83	-	-	47	272	272	-	-	989	-	-	-	-	40,169	2,671	-
2d.1.2.2	Electrical - Contaminated	-	478	48	11	-	442	-	237	1,216	1,216	-	-	-	2,356	-	-	-	155,755	10,768	-
2d.1.2.3	Fire Service & Sprinkler (RCA)	-	322	5	10	235	-	-	118	689	689	-	-	2,805	-	-	-	-	113,928	6,394	-
2d.1.2.4	HVAC - Fuel Handling	-	83	3	4	93	13	-	39	235	235	-	-	1,117	67	-	-	-	49,792	1,711	-
2d.1.2.5	Spent Fuel Cooling	-	564	142	30	-	1,240	-	470	2,445	2,445	-	-	-	6,727	-	-	-	436,613	13,648	-
2d.1.2.6	Waste Disposal	-	678	124	25	-	1,013	-	439	2,279	2,279	-	-	-	5,514	-	-	-	356,736	15,605	-
2d.1.2	Totals	-	2,261	323	83	411	2,708	-	1,349	7,136	7,136	-	-	4,911	14,665	-	-	-	1,152,993	50,798	-
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Handling	422	470	7	12	158	66	-	371	1,507	1,507	-	-	1,891	839	-	-	-	147,961	21,759	-
2d.1.3	Totals	422	470	7	12	158	66	-	371	1,507	1,507	-	-	1,891	839	-	-	-	147,961	21,759	-
2d.1.4	Scaffolding in support of decommissioning	-	314	6	1	26	5	-	84	436	436	-	-	275	24	-	-	-	13,996	8,705	-
2d.1	Subtotal Period 2d Activity Costs	901	3,089	547	119	595	3,672	-	2,303	11,226	11,226	-	-	7,078	20,290	-	-	-	1,629,660	82,573	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,448	434	1,882	1,882	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	847	254	1,102	1,102	-	-	-	-	-	-	-	-	18,850	-
2d.2.3	Operational Equipment	-	-	18	34	603	-	-	97	753	753	-	-	11,710	-	-	-	-	292,750	32	-
2d.2	Subtotal Period 2d Additional Costs	-	-	18	34	603	-	2,295	786	3,737	3,737	-	-	11,710	-	-	-	-	292,750	18,882	12,480
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	56	-	39	34	-	237	-	96	461	461	-	-	-	380	-	-	-	22,815	74	-
2d.3.3	Small tool allowance	-	61	-	-	-	-	-	9	70	70	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	141	31	556	99	-	127	954	954	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	3,696	554	4,250	-	4,250	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	56	61	179	65	556	336	3,696	787	5,736	1,486	4,250	-	6,000	909	-	-	-	327,783	162	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	168	-	-	-	-	-	-	42	209	209	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	550	55	605	605	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	908	-	-	-	-	-	227	1,135	1,135	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	2,399	-	-	-	-	-	360	2,759	2,759	-	-	-	-	-	-	-	-	-	-

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
	Period 2d Period-Dependent Costs (continued)																				
2d.4.6	Disposal of DAW generated	-	-	51	9	-	96	-	30	186	186	-	-	-	2,361	-	-	-	47,229	77	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	681	102	783	783	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	471	47	518	518	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	121	12	133	-	133	-	-	-	-	-	-	-	-	-
2d.4.10	Non-Labor Overhead	-	-	-	-	-	-	585	88	673	673	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	439	66	505	505	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	91	14	105	-	105	-	-	-	-	-	-	-	-	-
2d.4.13	Corporate A&G	-	-	-	-	-	-	1,196	179	1,375	1,375	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	2,658	399	3,056	3,056	-	-	-	-	-	-	-	-	-	79,440
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	8,131	1,220	9,351	9,351	-	-	-	-	-	-	-	-	-	94,571
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	11,174	1,676	12,850	12,850	-	-	-	-	-	-	-	-	-	180,631
2d.4	Subtotal Period 2d Period-Dependent Costs	168	3,307	51	9	-	96	26,096	4,517	34,243	34,006	238	-	-	2,361	-	-	-	47,229	77	354,643
2d.0	TOTAL PERIOD 2d COST	1,124	6,458	796	227	1,754	4,105	32,087	8,392	54,943	50,455	4,488	-	24,788	23,561	-	-	-	2,297,422	101,694	367,123
	PERIOD 2f - License Termination																				
	Period 2f Direct Decommissioning Activities																				
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	157	47	204	204	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	157	47	204	204	-	-	-	-	-	-	-	-	-	-
	Period 2f Additional Costs																				
2f.2.1	License Termination Survey	-	-	-	-	-	-	8,069	2,421	10,490	10,490	-	-	-	-	-	-	-	-	177,691	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	8,069	2,421	10,490	10,490	-	-	-	-	-	-	-	-	177,691	6,240
	Period 2f Collateral Costs																				
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
	Period 2f Period-Dependent Costs																				
2f.4.1	Insurance	-	-	-	-	-	-	452	45	497	497	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	830	-	-	-	-	-	207	1,037	1,037	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	1	-	14	-	5	28	28	-	-	-	351	-	-	-	7,020	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	280	42	322	322	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	438	44	482	482	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	99	10	109	-	109	-	-	-	-	-	-	-	-	-
2f.4.8	Non-Labor Overhead	-	-	-	-	-	-	259	39	298	298	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	75	11	86	-	86	-	-	-	-	-	-	-	-	-
2f.4.10	Corporate A&G	-	-	-	-	-	-	530	80	610	610	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	2,184	328	2,512	2,512	-	-	-	-	-	-	-	-	-	65,280
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	5,251	788	6,039	6,039	-	-	-	-	-	-	-	-	-	56,731
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	5,231	785	6,015	6,015	-	-	-	-	-	-	-	-	-	80,046
2f.4	Subtotal Period 2f Period-Dependent Costs	-	830	8	1	-	14	14,799	2,382	18,035	17,839	195	-	-	351	-	-	-	7,020	11	202,057
2f.0	TOTAL PERIOD 2f COST	-	830	8	1	-	14	24,348	5,049	30,250	30,054	195	-	-	351	-	-	-	7,020	177,702	208,297
	PERIOD 2 TOTALS	5,316	64,072	19,185	5,386	7,222	39,204	326,802	92,567	559,755	451,513	101,031	7,211	88,702	196,435	656	281	-	18,016,890	1,000,111	3,679,624
	PERIOD 3b - Site Restoration																				
	Period 3b Direct Decommissioning Activities																				
	Demolition of Remaining Site Buildings																				
3b.1.1.1	Reactor	-	2,143	-	-	-	-	-	321	2,465	-	-	2,465	-	-	-	-	-	-	21,113	-
3b.1.1.2	Auxiliary	-	1,499	-	-	-	-	-	225	1,723	-	-	1,723	-	-	-	-	-	-	11,256	-
3b.1.1.3	Circulating Water Intake	-	283	-	-	-	-	-	43	326	-	-	326	-	-	-	-	-	-	1,856	-
3b.1.1.4	Combined Maintenance Shop	-	218	-	-	-	-	-	33	251	-	-	251	-	-	-	-	-	-	3,080	-
3b.1.1.5	Containment Access Runway	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	148	-
3b.1.1.6	Contaminated Tool Warehouse	-	29	-	-	-	-	-	4	33	-	-	33	-	-	-	-	-	-	425	-
3b.1.1.7	Control Complex	-	773	-	-	-	-	-	116	889	-	-	889	-	-	-	-	-	-	8,975	-
3b.1.1.8	Cooling Tower	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	242	-
3b.1.1.9	Diesel Generator	-	156	-	-	-	-	-	23	180	-	-	180	-	-	-	-	-	-	1,274	-
3b.1.1.10	Diesel Oil Storage Tanks - Buried	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	48	-
3b.1.1.11	Emergency Response Building	-	242	-	-	-	-	-	36	278	-	-	278	-	-	-	-	-	-	3,445	-

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Demolition of Remaining Site Buildings (continued)																					
3b.1.1.12	Flex Storage Building	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	626	-
3b.1.1.13	Hot Machine Shop	-	70	-	-	-	-	-	11	81	-	-	81	-	-	-	-	-	-	874	-
3b.1.1.14	Intermediate	-	813	-	-	-	-	-	122	935	-	-	935	-	-	-	-	-	-	7,824	-
3b.1.1.15	Misc Site Concrete Pads	-	698	-	-	-	-	-	105	803	-	-	803	-	-	-	-	-	-	4,169	-
3b.1.1.16	Misc Site Structures	-	2,666	-	-	-	-	-	400	3,066	-	-	3,066	-	-	-	-	-	-	42,088	-
3b.1.1.17	Old Steam Generator Recycle Facility	-	117	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	693	-
3b.1.1.18	Reactor Building Retaining Wall	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	54	-
3b.1.1.19	Service	-	231	-	-	-	-	-	35	265	-	-	265	-	-	-	-	-	-	2,272	-
3b.1.1.20	Service Water Intake Pumphouse	-	220	-	-	-	-	-	33	253	-	-	253	-	-	-	-	-	-	1,406	-
3b.1.1.21	Site Paving	-	642	-	-	-	-	-	96	739	-	-	739	-	-	-	-	-	-	9,548	-
3b.1.1.22	Site Piping, Fencing & Rail	-	751	-	-	-	-	-	113	864	-	-	864	-	-	-	-	-	-	10,989	-
3b.1.1.23	Site Tank Pads	-	190	-	-	-	-	-	28	218	-	-	218	-	-	-	-	-	-	1,128	-
3b.1.1.24	Transformer Yard	-	116	-	-	-	-	-	17	133	-	-	133	-	-	-	-	-	-	689	-
3b.1.1.25	Turbine	-	1,525	-	-	-	-	-	229	1,754	-	-	1,754	-	-	-	-	-	-	26,458	-
3b.1.1.26	Turbine Pedestal	-	307	-	-	-	-	-	46	353	-	-	353	-	-	-	-	-	-	1,839	-
3b.1.1.27	Water Treatment	-	206	-	-	-	-	-	31	237	-	-	237	-	-	-	-	-	-	2,509	-
3b.1.1.28	Fuel Handling	-	554	-	-	-	-	-	83	637	-	-	637	-	-	-	-	-	-	6,825	-
3b.1.1	Totals	-	14,569	-	-	-	-	-	2,185	16,754	-	-	16,754	-	-	-	-	-	-	171,854	-
Site Closeout Activities																					
3b.1.2	BackFill Site	-	968	-	-	-	-	-	145	1,113	-	-	1,113	-	-	-	-	-	-	1,720	-
3b.1.3	Grade & landscape site	-	199	-	-	-	-	-	30	228	-	-	228	-	-	-	-	-	-	625	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	210	32	242	242	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	15,735	-	-	-	-	210	2,392	18,337	242	-	18,095	-	-	-	-	-	-	174,200	1,560
Period 3b Additional Costs																					
3b.2.1	Concrete Crushing	-	920	-	-	-	-	11	140	1,071	-	-	1,071	-	-	-	-	-	-	4,751	-
3b.2.2	Circ Water Cofferdam	-	233	-	-	-	-	-	35	268	-	-	268	-	-	-	-	-	-	1,936	-
3b.2.3	Service Water Cofferdam	-	319	-	-	-	-	-	48	366	-	-	366	-	-	-	-	-	-	2,714	-
3b.2.4	Construction Debris	-	-	-	-	-	-	341	51	392	-	-	392	-	-	-	-	-	-	-	-
3b.2	Subtotal Period 3b Additional Costs	-	1,472	-	-	-	-	352	274	2,098	-	-	2,098	-	-	-	-	-	-	9,401	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	118	-	-	-	-	-	18	136	-	-	136	-	-	-	-	-	-	-	-
3b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	7,356	1,103	8,460	-	8,460	-	-	-	-	-	-	-	-	-
3b.3.3	Non-Labor Overhead	-	-	-	-	-	-	254	38	292	-	-	292	-	-	-	-	-	-	-	-
3b.3.4	Corporate A&G	-	-	-	-	-	-	753	113	866	-	-	866	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	118	-	-	-	-	8,363	1,272	9,753	-	8,460	1,294	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	1,214	121	1,336	-	1,336	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	7,278	-	-	-	-	-	1,092	8,369	-	-	8,369	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	376	56	432	-	-	432	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	504	50	554	-	554	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	267	27	294	-	294	-	-	-	-	-	-	-	-	-
3b.4.7	ISFSI Operating Costs	-	-	-	-	-	-	201	30	231	-	231	-	-	-	-	-	-	-	-	-
3b.4.8	Security Staff Cost	-	-	-	-	-	-	5,870	880	6,750	(0)	5,332	1,417	-	-	-	-	-	-	-	175,440
3b.4.9	DOC Staff Cost	-	-	-	-	-	-	13,174	1,976	15,150	-	-	15,150	-	-	-	-	-	-	-	142,023
3b.4.10	Utility Staff Cost	-	-	-	-	-	-	7,356	1,103	8,459	0	1,946	6,514	-	-	-	-	-	-	-	113,827
3b.4	Subtotal Period 3b Period-Dependent Costs	-	7,278	-	-	-	-	28,962	5,337	41,576	-	9,693	31,883	-	-	-	-	-	-	-	431,290
3b.0	TOTAL PERIOD 3b COST	-	24,602	-	-	-	-	37,887	9,274	71,764	242	18,153	53,369	-	-	-	-	-	-	183,601	432,850
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	62,144	9,322	71,465	-	71,465	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	62,144	9,322	71,465	-	71,465	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	25,920	2,592	28,511	-	28,511	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	15,249	1,525	16,773	-	16,773	-	-	-	-	-	-	-	-	-

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3c Period-Dependent Costs (continued)																					
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	5,705	571	6,276	-	6,276	-	-	-	-	-	-	-	-	-
3c.4.6	Non-Labor Overhead	-	-	-	-	-	-	1,580	237	1,817	-	1,817	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	4,287	643	4,930	-	4,930	-	-	-	-	-	-	-	-	-
3c.4.8	Corporate A&G	-	-	-	-	-	-	3,984	598	4,582	-	4,582	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	98,372	14,756	113,128	-	113,128	-	-	-	-	-	-	-	-	2,763,606
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	36,350	5,453	41,803	-	41,803	-	-	-	-	-	-	-	-	601,753
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	191,448	26,373	217,821	-	217,821	-	-	-	-	-	-	-	-	3,365,358
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	253,591	35,695	289,286	-	289,286	-	-	-	-	-	-	-	-	3,365,358
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	2,000	-	-	11,639	-	2,246	15,884	15,884	-	-	-	-	-	-	1,773	363,061	-	-
3d.1.1	Totals	-	-	2,000	-	-	11,639	-	2,246	15,884	15,884	-	-	-	-	-	-	1,773	363,061	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	2,000	-	-	11,639	-	2,246	15,884	15,884	-	-	-	-	-	-	1,773	363,061	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	23	2	26	-	26	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	14	1	15	-	15	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	5	1	6	-	6	-	-	-	-	-	-	-	-	-
3d.4.6	Non-Labor Overhead	-	-	-	-	-	-	1	0	2	-	2	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	4	1	4	-	4	-	-	-	-	-	-	-	-	-
3d.4.8	Corporate A&G	-	-	-	-	-	-	4	1	4	-	4	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	88	13	102	-	102	-	-	-	-	-	-	-	-	2,480
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	33	5	38	-	38	-	-	-	-	-	-	-	-	540
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	172	24	195	-	195	-	-	-	-	-	-	-	-	3,020
3d.0	TOTAL PERIOD 3d COST	-	-	2,000	-	-	11,639	172	2,269	16,080	15,884	195	-	-	-	-	-	1,773	363,061	-	3,020
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	Decommissioning of ISFSI	-	132	95	147	-	2,096	2,032	1,126	5,628	5,628	-	-	-	30,414	-	-	-	1,706,855	13,195	1,872
3e.2	Subtotal Period 3e Additional Costs	-	132	95	147	-	2,096	2,032	1,126	5,628	5,628	-	-	-	30,414	-	-	-	1,706,855	13,195	1,872
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	117	29	146	146	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3e.4.3	Plant energy budget	-	-	-	-	-	-	62	16	78	78	-	-	-	-	-	-	-	-	-	-
3e.4.4	Non-Labor Overhead	-	-	-	-	-	-	12	3	15	15	-	-	-	-	-	-	-	-	-	-
3e.4.5	Corporate A&G	-	-	-	-	-	-	25	6	31	31	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	206	52	258	258	-	-	-	-	-	-	-	-	-	5,013
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	235	59	294	294	-	-	-	-	-	-	-	-	-	3,803
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	658	164	822	822	-	-	-	-	-	-	-	-	-	8,816
3e.0	TOTAL PERIOD 3e COST	-	132	95	147	-	2,096	2,690	1,290	6,450	6,450	-	-	-	30,414	-	-	-	1,706,855	13,195	10,688
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition of ISFSI	-	3,295	-	-	-	-	58	503	3,856	-	-	3,856	-	-	-	-	-	-	32,435	160
3f.2	Subtotal Period 3f Additional Costs	-	3,295	-	-	-	-	58	503	3,856	-	-	3,856	-	-	-	-	-	-	32,435	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	-	-

Table C
Virgil C. Summer Nuclear Station
DECON Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	148	-	-	-	-	-	22	170	-	-	170	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	31	5	36	-	-	36	-	-	-	-	-	-	-	-
3f.4.5	Non-Labor Overhead	-	-	-	-	-	-	4	1	5	-	-	5	-	-	-	-	-	-	-	-
3f.4.6	Corporate A&G	-	-	-	-	-	-	10	2	12	-	-	12	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	104	16	120	-	-	120	-	-	-	-	-	-	-	2,527
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	107	16	123	-	-	123	-	-	-	-	-	-	-	1,569
3f.4	Subtotal Period 3f Period-Dependent Costs	-	148	-	-	-	-	257	61	465	-	-	465	-	-	-	-	-	-	-	4,096
3f.0	TOTAL PERIOD 3f COST	-	3,480	-	-	-	-	315	569	4,363	-	-	4,363	-	-	-	-	-	-	32,435	4,256
PERIOD 3 TOTALS		-	28,214	2,095	147	-	13,734	294,655	49,098	387,943	22,576	307,635	57,733	-	30,414	-	-	1,773	2,069,916	229,230	3,816,172
TOTAL COST TO DECOMMISSION		**8,543**	**95,350**	**21,397**	**5,690**	**7,222**	**54,675**	**753,256**	**162,632**	**1,108,765**	**629,138**	**413,016**	**66,611**	**88,702**	**228,149**	**1,294**	**281**	**1,773**	**20,194,120**	**1,253,424**	**8,882,609**

TOTAL COST TO DECOMMISSION WITH 17.19% CONTINGENCY:	**$1,108,765**	**thousands of 2016 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 56.74% OR:	**$629,138**	**thousands of 2016 dollars**
SPENT FUEL MANAGEMENT COST IS 37.25% OR:	**$413,016**	**thousands of 2016 dollars**
NON-NUCLEAR DEMOLITION COST IS 6.01% OR:	**$66,611**	**thousands of 2016 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**229,723**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,773**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**52,852**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,253,424**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense.
a - indicates that this activity performed by decommissioning staff.
0 - indicates that this value is less than 0.5 but is non-zero.
a cell containing " - " indicates a zero value

APPENDIX D

DETAILED COST ANALYSIS

SAFSTOR-1

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	353	106	459	459	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	269	40	310	310	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	202	30	232	232	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	417	63	480	480	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	673	101	774	774	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
1a.1.16.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	662	99	762	762	-	-	-	-	-	-	-	-	-	4,920
1a.1.16.2	Plant systems	-	-	-	-	-	-	561	84	645	645	-	-	-	-	-	-	-	-	-	4,167
1a.1.16.3	Plant structures and buildings	-	-	-	-	-	-	420	63	483	483	-	-	-	-	-	-	-	-	-	3,120
1a.1.16.4	Waste management	-	-	-	-	-	-	269	40	310	310	-	-	-	-	-	-	-	-	-	2,000
1a.1.16.5	Facility and site dormancy	-	-	-	-	-	-	269	40	310	310	-	-	-	-	-	-	-	-	-	2,000
1a.1.16	Total	-	-	-	-	-	-	2,182	327	2,509	2,509	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.17.1	Plant systems	-	-	-	-	-	-	159	24	183	183	-	-	-	-	-	-	-	-	-	1,183
1a.1.17.2	Facility closeout & dormancy	-	-	-	-	-	-	162	24	186	186	-	-	-	-	-	-	-	-	-	1,200
1a.1.17	Total	-	-	-	-	-	-	321	48	369	369	-	-	-	-	-	-	-	-	-	2,383
1a.1.18	Procure vacuum drying system	-	-	-	-	-	-	13	2	15	15	-	-	-	-	-	-	-	-	-	100
1a.1.19	Drain/de-energize non-cont. systems									a											
1a.1.20	Drain & dry NSSS									a											
1a.1.21	Drain/de-energize contaminated systems									a											
1a.1.22	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,185	831	6,016	6,016	-	-	-	-	-	-	-	-	-	35,890
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	3,275	327	3,602	3,602	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	13,564	1,356	14,921	14,921	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	643	643	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	707	-	-	-	-	-	106	813	813	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	2	-	25	-	8	48	48	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,876	281	2,158	2,158	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,142	114	1,256	1,256	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,009	101	1,110	-	1,110	-	-	-	-	-	-	-	-	-
1a.4.9	Non-Labor Overhead	-	-	-	-	-	-	1,312	197	1,509	1,509	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	801	120	921	-	921	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	100	15	115	-	115	-	-	-	-	-	-	-	-	-
1a.4.12	Corporate A&G	-	-	-	-	-	-	2,804	421	3,224	3,224	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	12,906	1,936	14,842	14,842	-	-	-	-	-	-	-	-	-	381,686
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	24,505	3,676	28,180	28,180	-	-	-	-	-	-	-	-	-	423,400
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,221	13	2	-	25	63,295	8,787	73,343	71,197	2,146	-	-	610	-	-	-	12,190	20	805,086
1a.0	TOTAL PERIOD 1a COST	-	1,221	13	2	-	25	68,480	9,618	79,359	77,213	2,146	-	-	610	-	-	-	12,190	20	840,976
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	986	-	-	-	-	-	-	493	1,480	1,480	-	-	-	-	-	-	-	-	23,680	-
1b.1.1.2	Auxiliary	728	-	-	-	-	-	-	364	1,091	1,091	-	-	-	-	-	-	-	-	17,334	-
1b.1.1.3	Contaminated Tool Warehouse	28	-	-	-	-	-	-	14	41	41	-	-	-	-	-	-	-	-	640	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings (continued)																					
1b.1.1.4	Control Complex	79	-	-	-	-	-	-	40	119	119	-	-	-	-	-	-	-	-	1,855	-
1b.1.1.5	Fuel Handling	373	-	-	-	-	-	-	186	559	559	-	-	-	-	-	-	-	-	9,025	-
1b.1.1.6	Hot Machine Shop	19	-	-	-	-	-	-	10	29	29	-	-	-	-	-	-	-	-	451	-
1b.1.1.7	Intermediate	110	-	-	-	-	-	-	55	165	165	-	-	-	-	-	-	-	-	2,580	-
1b.1.1.8	Old Steam Generator Recycle Facility	27	-	-	-	-	-	-	14	41	41	-	-	-	-	-	-	-	-	632	-
1b.1.1	Totals	2,350	-	-	-	-	-	-	1,175	3,526	3,526	-	-	-	-	-	-	-	-	56,197	-
1b.1	Subtotal Period 1b Activity Costs	2,350	-	-	-	-	-	-	1,175	3,526	3,526	-	-	-	-	-	-	-	-	56,197	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	946	-	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	196	-	126	112	-	772	-	321	1,527	1,527	-	-	-	1,240	-	-	-	74,407	242	-
1b.3.4	Small tool allowance	-	37	-	-	-	-	-	6	43	43	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,143	37	126	112	-	772	-	468	2,657	2,657	-	-	-	1,240	-	-	-	74,407	242	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,129	-	-	-	-	-	-	282	1,411	1,411	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	825	83	908	908	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	399	-	-	-	-	-	100	498	498	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	178	-	-	-	-	-	27	205	205	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	16	3	-	30	-	10	59	59	-	-	-	743	-	-	-	14,869	24	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	473	71	544	544	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	169	17	186	186	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	254	25	280	-	280	-	-	-	-	-	-	-	-	-
1b.4.10	Non-Labor Overhead	-	-	-	-	-	-	331	50	380	380	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	232	-	232	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	25	4	29	-	29	-	-	-	-	-	-	-	-	-
1b.4.13	Corporate A&G	-	-	-	-	-	-	707	106	813	813	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,253	488	3,741	3,741	-	-	-	-	-	-	-	-	-	96,206
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,177	926	7,103	7,103	-	-	-	-	-	-	-	-	-	106,720
1b.4	Subtotal Period 1b Period-Dependent Costs	1,129	577	16	3	-	30	12,416	2,218	16,389	15,848	541	-	-	743	-	-	-	14,869	24	202,926
1b.0	TOTAL PERIOD 1b COST	4,622	614	142	115	-	802	12,416	3,861	22,572	22,031	541	-	-	1,984	-	-	-	89,276	56,463	202,926
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	400	-	-	-	-	-	60	460	460	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	28	-	-	-	-	-	4	32	32	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	15,343	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	79	12	90	90	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	427	-	-	-	-	811	296	1,535	1,535	-	-	-	-	-	-	-	-	19,043	583
Period 1c Additional Costs																					
1c.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,358	1,704	13,062	13,062	-	-	-	-	-	-	-	-	-	-
1c.2	Subtotal Period 1c Additional Costs	-	-	-	-	-	-	11,358	1,704	13,062	13,062	-	-	-	-	-	-	-	-	-	-
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	201	-	129	115	-	791	-	328	1,565	1,565	-	-	-	1,271	-	-	-	76,282	248	-
1c.3.3	Small tool allowance	-	3	-	-	-	-	-	0	3	3	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,072	161	1,233	-	1,233	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	201	3	129	115	-	791	1,072	490	2,801	1,568	1,233	-	-	1,271	-	-	-	76,282	248	-
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	834	83	918	918	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	223	-	-	-	-	-	56	279	279	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	180	-	-	-	-	-	27	207	207	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	6	-	2	12	12	-	-	-	155	-	-	-	3,106	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	478	72	550	550	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	171	17	188	188	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	257	26	283	-	283	-	-	-	-	-	-	-	-	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

						Off-Site	LLRW				NRC	Spent Fuel	Site	Processed	Burial Volumes				Burial /		Utility and
Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Processing Costs	Disposal Costs	Other Costs	Total Contingency	Total Costs	Lic. Term. Costs	Management Costs	Restoration Costs	Volume Cu. Feet	Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Processed Wt., Lbs.	Craft Manhours	Contractor Manhours
Period 1c Period-Dependent Costs (continued)																					
1c.4.9	Non-Labor Overhead	-	-	-	-	-	-	334	50	384	384	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	204	31	235	-	235	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	26	4	29	-	29	-	-	-	-	-	-	-	-	-
1c.4.12	Corporate A&G	-	-	-	-	-	-	714	107	821	821	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	3,288	493	3,782	3,782	-	-	-	-	-	-	-	-	-	97,251
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,244	937	7,180	7,180	-	-	-	-	-	-	-	-	-	107,880
1c.4	Subtotal Period 1c Period-Dependent Costs	-	403	3	1	-	6	12,551	1,904	14,869	14,322	547	-	-	155	-	-	-	3,106	5	205,131
1c.0	TOTAL PERIOD 1c COST	201	833	133	116	-	797	25,793	4,393	32,265	30,485	1,780	-	-	1,427	-	-	-	79,388	19,296	205,715
PERIOD 1 TOTALS		4,823	2,668	288	233	-	1,624	106,688	17,873	134,196	129,729	4,467	-	-	4,020	-	-	-	180,855	75,779	1,249,616
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	1,234	185	1,420	1,420	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	769	192	962	962	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	2,004	377	2,381	2,381	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	57,382	8,607	65,989	-	65,989	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	57,382	8,607	65,989	-	65,989	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	3,334	333	3,668	3,536	132	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	1,135	-	-	-	-	-	284	1,419	1,419	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	27	5	-	52	-	16	100	100	-	-	-	1,265	-	-	-	25,302	41	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	2,064	310	2,373	1,187	1,187	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	1,571	157	1,729	1,729	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,253	225	2,478	-	2,478	-	-	-	-	-	-	-	-	-
2a.4.8	Non-Labor Overhead	-	-	-	-	-	-	1,268	190	1,458	323	1,135	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	4,404	661	5,064	-	5,064	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	551	83	634	-	634	-	-	-	-	-	-	-	-	-
2a.4.11	Corporate A&G	-	-	-	-	-	-	3,000	450	3,450	764	2,685	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	37,626	5,644	43,270	8,342	34,928	-	-	-	-	-	-	-	-	997,766
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	26,942	4,041	30,983	6,534	24,449	-	-	-	-	-	-	-	-	453,009
2a.4	Subtotal Period 2a Period-Dependent Costs	-	1,135	27	5	-	52	83,013	12,394	96,625	23,932	72,693	-	-	1,265	-	-	-	25,302	41	1,450,774
2a.0	TOTAL PERIOD 2a COST	-	1,135	27	5	-	52	142,398	21,379	164,995	26,313	138,682	-	-	1,265	-	-	-	25,302	41	1,450,774
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	10,425	1,564	11,988	11,988	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	6,497	1,624	8,121	8,121	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	16,921	3,188	20,109	20,109	-	-	-	-	-	-	-	-	-	-
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	73,196	10,979	84,175	-	84,175	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	73,196	10,979	84,175	-	84,175	-	-	-	-	-	-	-	-	-
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	28,159	2,816	30,975	29,858	1,117	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	4,649	-	-	-	-	-	1,162	5,812	5,812	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	110	20	-	209	-	66	405	405	-	-	-	5,132	-	-	-	102,643	167	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	8,713	1,307	10,020	10,020	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	12,674	1,267	13,941	13,941	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	6,198	620	6,818	-	6,818	-	-	-	-	-	-	-	-	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
	Period 2b Period-Dependent Costs (continued)																				
2b.4.8	Non-Labor Overhead	-	-	-	-	-	-	4,336	650	4,986	2,727	2,259	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	4,657	699	5,356	-	5,356	-	-	-	-	-	-	-	-	-
2b.4.10	Corporate A&G	-	-	-	-	-	-	10,261	1,539	11,800	6,453	5,347	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	136,091	20,414	156,504	70,445	86,059	-	-	-	-	-	-	-	-	4,067,760
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	91,525	13,729	105,253	55,180	50,073	-	-	-	-	-	-	-	-	1,549,623
2b.4	Subtotal Period 2b Period-Dependent Costs	-	4,649	110	20	-	209	302,613	44,269	351,871	194,841	157,030	-	-	5,132	-	-	-	102,643	167	5,617,383
2b.0	TOTAL PERIOD 2b COST	-	4,649	110	20	-	209	392,731	58,436	456,155	214,950	241,205	-	-	5,132	-	-	-	102,643	167	5,617,383
	PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																				
	Period 2c Direct Decommissioning Activities																				
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	181	27	209	209	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	113	28	141	141	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	295	55	350	350	-	-	-	-	-	-	-	-	-	-
	Period 2c Period-Dependent Costs																				
2c.4.1	Insurance	-	-	-	-	-	-	472	47	520	520	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	76	-	-	-	-	-	19	95	95	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	2	0	-	3	-	1	6	6	-	-	-	82	-	-	-	1,645	3	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	152	23	174	174	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	203	20	224	224	-	-	-	-	-	-	-	-	-	-
2c.4.7	Non-Labor Overhead	-	-	-	-	-	-	41	6	47	47	-	-	-	-	-	-	-	-	-	-
2c.4.8	Corporate A&G	-	-	-	-	-	-	98	15	112	112	-	-	-	-	-	-	-	-	-	-
2c.4.9	Security Staff Cost	-	-	-	-	-	-	1,066	160	1,226	1,226	-	-	-	-	-	-	-	-	-	25,286
2c.4.10	Utility Staff Cost	-	-	-	-	-	-	835	125	960	960	-	-	-	-	-	-	-	-	-	14,750
2c.4	Subtotal Period 2c Period-Dependent Costs	-	76	2	0	-	3	2,868	416	3,366	3,366	-	-	-	82	-	-	-	1,645	3	40,036
2c.0	TOTAL PERIOD 2c COST	-	76	2	0	-	3	3,162	472	3,716	3,716	-	-	-	82	-	-	-	1,645	3	40,036
	PERIOD 2 TOTALS	-	5,861	139	25	-	264	538,291	80,287	624,866	244,979	379,887	-	-	6,480	-	-	-	129,591	211	7,108,192
	PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																				
	Period 3a Direct Decommissioning Activities																				
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	1,010	151	1,161	1,161	-	-	-	-	-	-	-	-	-	7,500
3a.1.7	Perform SER and EA	-	-	-	-	-	-	417	63	480	480	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	673	101	774	774	-	-	-	-	-	-	-	-	-	5,000
3a.1.9	Prepare/submit License Termination Plan	-	-	-	-	-	-	551	83	634	634	-	-	-	-	-	-	-	-	-	4,096
3a.1.10	Receive NRC approval of termination plan									a											
	Activity Specifications																				
3a.1.11.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	992	149	1,141	1,027	-	114	-	-	-	-	-	-	-	7,370
3a.1.11.2	Plant systems	-	-	-	-	-	-	561	84	645	581	-	65	-	-	-	-	-	-	-	4,167
3a.1.11.3	Reactor internals	-	-	-	-	-	-	956	143	1,099	1,099	-	-	-	-	-	-	-	-	-	7,100
3a.1.11.4	Reactor vessel	-	-	-	-	-	-	875	131	1,006	1,006	-	-	-	-	-	-	-	-	-	6,500
3a.1.11.5	Biological shield	-	-	-	-	-	-	67	10	77	77	-	-	-	-	-	-	-	-	-	500
3a.1.11.6	Steam generators	-	-	-	-	-	-	420	63	483	483	-	-	-	-	-	-	-	-	-	3,120
3a.1.11.7	Reinforced concrete	-	-	-	-	-	-	215	32	248	124	-	124	-	-	-	-	-	-	-	1,600
3a.1.11.8	Main Turbine	-	-	-	-	-	-	54	8	62	-	-	62	-	-	-	-	-	-	-	400
3a.1.11.9	Main Condensers	-	-	-	-	-	-	54	8	62	-	-	62	-	-	-	-	-	-	-	400
3a.1.11.10	Plant structures & buildings	-	-	-	-	-	-	420	63	483	242	-	242	-	-	-	-	-	-	-	3,120
3a.1.11.11	Waste management	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
3a.1.11.12	Facility & site closeout	-	-	-	-	-	-	121	18	139	70	-	70	-	-	-	-	-	-	-	900
3a.1.11	Total	-	-	-	-	-	-	5,355	803	6,158	5,421	-	738	-	-	-	-	-	-	-	39,777

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Planning & Site Preparations																					
3a.1.12	Prepare dismantling sequence	-	-	-	-	-	-	323	48	372	372	-	-	-	-	-	-	-	-	-	2,400
3a.1.13	Plant prep. & temp. svces	-	-	-	-	-	-	3,200	480	3,680	3,680	-	-	-	-	-	-	-	-	-	-
3a.1.14	Design water clean-up system	-	-	-	-	-	-	188	28	217	217	-	-	-	-	-	-	-	-	-	1,400
3a.1.15	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.16	Procure casks/liners & containers	-	-	-	-	-	-	166	25	190	190	-	-	-	-	-	-	-	-	-	1,230
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	15,288	2,293	17,581	16,844	-	738	-	-	-	-	-	-	-	72,703
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	3,640	1,092	4,733	4,733	-	-	-	-	-	-	-	-	22,800	8,812
3a.2	Subtotal Period 3a Additional Costs	-	-	-	-	-	-	3,640	1,092	4,733	4,733	-	-	-	-	-	-	-	-	22,800	8,812
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	585	58	643	643	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	450	-	-	-	-	-	112	562	562	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	707	-	-	-	-	-	106	813	813	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	2	-	21	-	7	41	41	-	-	-	514	-	-	-	10,287	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,876	281	2,158	2,158	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	371	37	408	408	-	-	-	-	-	-	-	-	-	-
3a.4.8	Non-Labor Overhead	-	-	-	-	-	-	948	142	1,090	1,090	-	-	-	-	-	-	-	-	-	-
3a.4.9	Corporate A&G	-	-	-	-	-	-	1,713	257	1,969	1,969	-	-	-	-	-	-	-	-	-	-
3a.4.10	Security Staff Cost	-	-	-	-	-	-	1,925	289	2,213	2,213	-	-	-	-	-	-	-	-	-	65,179
3a.4.11	Utility Staff Cost	-	-	-	-	-	-	15,147	2,272	17,419	17,419	-	-	-	-	-	-	-	-	-	258,629
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,156	11	2	-	21	22,564	3,562	27,316	27,316	-	-	-	514	-	-	-	10,287	17	323,807
3a.0	TOTAL PERIOD 3a COST	-	1,156	11	2	-	21	41,492	6,947	49,630	48,892	-	738	-	514	-	-	-	10,287	22,817	405,322
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	637	96	733	660	-	73	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	337	50	387	387	-	-	-	-	-	-	-	-	-	2,500
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	182	27	209	52	-	157	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	3,630
3b.1.1.8	Facility closeout	-	-	-	-	-	-	162	24	186	93	-	93	-	-	-	-	-	-	-	1,200
3b.1.1.9	Missile shields	-	-	-	-	-	-	61	9	70	70	-	-	-	-	-	-	-	-	-	450
3b.1.1.10	Biological shield	-	-	-	-	-	-	162	24	186	186	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.11	Steam generators	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	135	20	155	77	-	77	-	-	-	-	-	-	-	1,000
3b.1.1.13	Main Turbine	-	-	-	-	-	-	210	32	242	-	-	242	-	-	-	-	-	-	-	1,560
3b.1.1.14	Main Condensers	-	-	-	-	-	-	210	32	242	-	-	242	-	-	-	-	-	-	-	1,560
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	368	55	423	380	-	42	-	-	-	-	-	-	-	2,730
3b.1.1.16	Reactor building	-	-	-	-	-	-	368	55	423	380	-	42	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	4,341	651	4,992	4,024	-	968	-	-	-	-	-	-	-	32,243
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	4,341	651	4,992	4,024	-	968	-	-	-	-	-	-	-	32,243
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	946	-	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	946	1,200	-	-	-	-	1,323	520	3,989	3,989	-	-	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	29	-	-	-	-	-	-	7	37	37	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	307	31	338	338	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	251	-	-	-	-	-	63	314	314	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	358	-	-	-	-	-	54	412	412	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	1	-	12	-	4	23	23	-	-	-	295	-	-	-	5,898	10	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	951	143	1,094	1,094	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	188	19	207	207	-	-	-	-	-	-	-	-	-	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
	Period 3b Period-Dependent Costs (continued)																				
3b.4.9	Non-Labor Overhead	-	-	-	-	-	-	480	72	552	552	-	-	-	-	-	-	-	-	-	-
3b.4.10	Corporate A&G	-	-	-	-	-	-	868	130	998	998	-	-	-	-	-	-	-	-	-	-
3b.4.11	Security Staff Cost	-	-	-	-	-	-	975	146	1,122	1,122	-	-	-	-	-	-	-	-	-	33,036
3b.4.12	DOC Staff Cost	-	-	-	-	-	-	5,334	800	6,135	6,135	-	-	-	-	-	-	-	-	-	59,200
3b.4.13	Utility Staff Cost	-	-	-	-	-	-	7,677	1,152	8,829	8,829	-	-	-	-	-	-	-	-	-	131,086
3b.4	Subtotal Period 3b Period-Dependent Costs	29	609	6	1	-	12	16,782	2,620	20,060	20,060	-	-	-	295	-	-	-	5,898	10	223,321
3b.0	TOTAL PERIOD 3b COST	975	1,809	6	1	-	12	22,445	3,792	29,041	28,073	-	968	-	295	-	-	-	5,898	10	255,564
PERIOD 3 TOTALS		975	2,966	17	3	-	33	63,937	10,739	78,671	76,965	-	1,705	-	809	-	-	-	16,185	22,826	660,886
PERIOD 4a - Large Component Removal																					
	Period 4a Direct Decommissioning Activities																				
	Nuclear Steam Supply System Removal																				
4a.1.1.1	Reactor Coolant Piping	14	51	12	4	64	97	-	55	297	297	-	-	281	297	-	-	-	65,195	1,538	-
4a.1.1.2	Pressurizer Relief Tank	4	15	6	2	30	42	-	22	120	120	-	-	133	133	-	-	-	29,424	480	-
4a.1.1.3	Reactor Coolant Pumps & Motors	12	51	43	152	-	245	-	107	611	611	-	-	-	3,322	-	-	-	605,445	2,001	80
4a.1.1.4	Pressurizer	7	39	437	151	-	211	-	132	976	976	-	-	-	2,862	-	-	-	190,272	1,501	1,500
4a.1.1.5	Steam Generators	47	5,645	2,755	1,639	-	2,062	-	2,472	14,619	14,619	-	-	-	27,948	-	-	-	2,412,202	8,301	2,250
4a.1.1.6	Retired Steam Generator Units	-	-	2,755	1,639	-	2,062	-	1,037	7,493	7,493	-	-	-	27,948	-	-	-	2,250,000	-	2,250
4a.1.1.7	CRDMs/ICIs/Service Structure Removal	24	165	207	11	57	291	-	157	913	913	-	-	753	2,604	-	-	-	130,284	4,687	-
4a.1.1.8	Reactor Vessel Internals	35	4,750	5,747	230	-	3,492	221	6,853	21,328	21,328	-	-	-	1,579	376	281	-	219,076	17,873	873
4a.1.1.9	Vessel & Internals GTCC Disposal	-	-	-	-	-	11,639	-	1,746	13,384	13,384	-	-	-	-	-	-	1,773	363,061	-	-
4a.1.1.10	Reactor Vessel	-	7,308	1,157	90	-	6,522	221	9,087	24,385	24,385	-	-	-	7,625	-	-	-	769,200	17,873	873
4a.1.1	Totals	143	18,024	13,118	3,919	152	26,661	441	21,668	84,127	84,127	-	-	1,167	74,318	376	281	1,773	7,034,158	54,256	7,827
	Removal of Major Equipment																				
4a.1.2	Main Turbine/Generator	-	233	158	29	469	397	-	248	1,533	1,533	-	-	5,060	2,113	-	-	-	367,369	5,959	-
4a.1.3	Main Condensers	-	756	184	34	547	463	-	410	2,395	2,395	-	-	5,901	2,464	-	-	-	428,414	19,204	-
	Cascading Costs from Clean Building Demolition																				
4a.1.4.1	Reactor	-	377	-	-	-	-	-	57	434	434	-	-	-	-	-	-	-	-	3,705	-
4a.1.4.2	Auxiliary	-	164	-	-	-	-	-	25	189	189	-	-	-	-	-	-	-	-	1,189	-
4a.1.4.3	Fuel Handling	-	57	-	-	-	-	-	9	66	66	-	-	-	-	-	-	-	-	648	-
4a.1.4	Totals	-	599	-	-	-	-	-	90	689	689	-	-	-	-	-	-	-	-	5,542	-
	Disposal of Plant Systems																				
4a.1.5.1	Aux Boiler Steam & Reheat	-	35	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	938	-
4a.1.5.2	Aux Boiler Steam & Reheat (RCA)	-	83	4	9	225	-	-	56	379	379	-	-	2,692	-	-	-	-	109,340	1,764	-
4a.1.5.3	Auxiliary Coolant	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	665	-
4a.1.5.4	Breathing Air (RCA)	-	24	0	0	11	-	-	8	43	43	-	-	131	-	-	-	-	5,326	451	-
4a.1.5.5	Carbon Dioxide - Gen Gas & Vents	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	140	-
4a.1.5.6	Chemical Cleaning	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	244	-
4a.1.5.7	Chilled Water	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	2,963	-
4a.1.5.8	Component Cooling	-	72	-	-	-	-	-	11	83	-	-	83	-	-	-	-	-	-	1,927	-
4a.1.5.9	Condensate	-	214	-	-	-	-	-	32	246	-	-	246	-	-	-	-	-	-	5,692	-
4a.1.5.10	Condensate Demin	-	35	-	-	-	-	-	5	40	-	-	40	-	-	-	-	-	-	923	-
4a.1.5.11	Condenser Air Removal	-	85	-	-	-	-	-	13	97	-	-	97	-	-	-	-	-	-	2,274	-
4a.1.5.12	Condenser Cleaning	-	12	-	-	-	-	-	2	14	-	-	14	-	-	-	-	-	-	317	-
4a.1.5.13	Demineralized Water	-	39	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	1,003	-
4a.1.5.14	Emergency Feedwater	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	654	-
4a.1.5.15	Emergency Feedwater (RCA)	-	43	1	3	72	-	-	22	141	141	-	-	855	-	-	-	-	34,715	984	-
4a.1.5.16	Extraction Steam	-	70	-	-	-	-	-	10	80	-	-	80	-	-	-	-	-	-	1,882	-
4a.1.5.17	Feedwater	-	299	-	-	-	-	-	45	344	-	-	344	-	-	-	-	-	-	8,000	-
4a.1.5.18	Feedwater (RCA)	-	51	3	6	149	-	-	36	245	245	-	-	1,782	-	-	-	-	72,373	1,161	-
4a.1.5.19	Filtered & Raw Water Treatment	-	159	-	-	-	-	-	24	183	-	-	183	-	-	-	-	-	-	4,169	-
4a.1.5.20	Gland Sealing Steam	-	28	-	-	-	-	-	4	32	-	-	32	-	-	-	-	-	-	773	-
4a.1.5.21	Heater Drains & Vents	-	160	-	-	-	-	-	24	184	-	-	184	-	-	-	-	-	-	4,322	-
4a.1.5.22	HVAC - Control Bldg	-	34	-	-	-	-	-	5	39	-	-	39	-	-	-	-	-	-	954	-
4a.1.5.23	HVAC - Intermediate	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	823	-
4a.1.5.24	HVAC - Misc Bldgs	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	1,436	-
4a.1.5.25	HVAC - Turbine	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,876	-
4a.1.5.26	Hydrogen	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	106	-
4a.1.5.27	Hydrogen - Plant (NSSS H & O2)	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	206	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4a.1.5.28	Instrument Air	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,040	-
4a.1.5.29	Lube Oil	-	53	-	-	-	-	-	8	60	-	-	60	-	-	-	-	-	-	1,390	-
4a.1.5.30	Main Steam	-	154	-	-	-	-	-	23	177	-	-	177	-	-	-	-	-	-	4,133	-
4a.1.5.31	Main Steam (RCA)	-	65	3	5	131	-	-	37	241	241	-	-	1,563	-	-	-	-	63,494	1,396	-
4a.1.5.32	Main Steam Dump	-	23	-	-	-	-	-	4	27	-	-	27	-	-	-	-	-	-	639	-
4a.1.5.33	Nitrogen & Oxygen	-	16	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	404	-
4a.1.5.34	Nitrogen & Oxygen (RCA)	-	56	1	1	34	-	-	19	112	112	-	-	404	-	-	-	-	16,411	1,055	-
4a.1.5.35	Non-Nuclear Plant Drains	-	56	-	-	-	-	-	8	64	-	-	64	-	-	-	-	-	-	1,515	-
4a.1.5.36	Nuclear Blowdown Processing	-	224	5	10	240	-	-	94	573	573	-	-	2,868	-	-	-	-	116,458	5,018	-
4a.1.5.37	PASS - H2 Removal	-	31	1	2	41	-	-	14	89	89	-	-	486	-	-	-	-	19,748	745	-
4a.1.5.38	Reactor Coolant	-	198	150	27	-	1,113	-	347	1,834	1,834	-	-	-	5,914	-	-	-	391,758	4,793	-
4a.1.5.39	Reheat Steam	-	82	-	-	-	-	-	12	95	-	-	95	-	-	-	-	-	-	2,195	-
4a.1.5.40	RX Leak Rate Testing	-	11	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	295	-
4a.1.5.41	Safety Injection	-	470	91	17	-	683	-	300	1,561	1,561	-	-	-	3,667	-	-	-	240,663	10,564	-
4a.1.5.42	Steam Gen Blowdown	-	42	-	-	-	-	-	6	48	-	-	48	-	-	-	-	-	-	1,059	-
4a.1.5.43	Steam Gen Blowdown (RCA)	-	22	0	0	9	-	-	7	39	39	-	-	109	-	-	-	-	4,425	478	-
4a.1.5.44	TB Closed Cycle Cooling	-	56	-	-	-	-	-	8	64	-	-	64	-	-	-	-	-	-	1,492	-
4a.1.5.45	TB Cycle Chem Feed	-	81	-	-	-	-	-	12	93	-	-	93	-	-	-	-	-	-	2,088	-
4a.1.5.46	TB Cycle Sampling	-	37	-	-	-	-	-	6	43	-	-	43	-	-	-	-	-	-	962	-
4a.1.5.47	Turbine Systems	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	657	-
4a.1.5	Totals	-	3,518	259	82	911	1,796	-	1,278	7,845	5,257	-	2,588	10,891	9,581	-	-	-	1,074,710	88,565	-
4a.1.6	Scaffolding in support of decommissioning	-	1,156	26	5	102	18	-	312	1,619	1,619	-	-	1,101	97	-	-	-	55,984	32,043	-
4a.1	Subtotal Period 4a Activity Costs	143	24,287	13,745	4,069	2,181	29,335	441	24,006	98,207	95,619	-	2,588	24,120	88,574	376	281	1,773	8,960,635	205,569	7,827
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,027	308	1,335	1,335	-	-	-	-	-	-	-	-	22,836	-
4a.2	Subtotal Period 4a Additional Costs	-	-	-	-	-	-	1,027	308	1,335	1,335	-	-	-	-	-	-	-	-	22,836	-
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	5	-	9	8	-	52	-	18	91	91	-	-	-	84	-	-	-	5,038	16	-
4a.3.3	Small tool allowance	-	165	-	-	-	-	-	25	190	171	-	19	-	-	-	-	-	-	-	-
4a.3.4	On-site survey and release of 27.16 tons clean metallic waste	-	-	-	-	-	-	47	5	51	51	-	-	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	5	165	9	8	-	52	47	47	333	314	-	19	-	84	-	-	-	5,038	16	-
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	64	-	-	-	-	-	-	16	80	80	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	666	67	733	733	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,646	-	-	-	-	-	412	2,058	2,058	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,830	-	-	-	-	-	425	3,255	3,255	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	71	13	-	136	-	43	263	263	-	-	-	3,338	-	-	-	66,757	109	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	1,958	294	2,252	2,252	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	646	65	710	710	-	-	-	-	-	-	-	-	-	-
4a.4.9	Non-Labor Overhead	-	-	-	-	-	-	944	142	1,086	1,086	-	-	-	-	-	-	-	-	-	-
4a.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	531	80	611	611	-	-	-	-	-	-	-	-	-	-
4a.4.11	Corporate A&G	-	-	-	-	-	-	1,897	284	2,181	2,181	-	-	-	-	-	-	-	-	-	-
4a.4.12	Security Staff Cost	-	-	-	-	-	-	2,114	317	2,431	2,431	-	-	-	-	-	-	-	-	-	71,607
4a.4.13	DOC Staff Cost	-	-	-	-	-	-	13,357	2,004	15,361	15,361	-	-	-	-	-	-	-	-	-	158,109
4a.4.14	Utility Staff Cost	-	-	-	-	-	-	16,740	2,511	19,251	19,251	-	-	-	-	-	-	-	-	-	286,429
4a.4	Subtotal Period 4a Period-Dependent Costs	64	4,477	71	13	-	136	38,854	6,658	50,272	50,272	-	-	-	3,338	-	-	-	66,757	109	516,144
4a.0	TOTAL PERIOD 4a COST	212	28,929	13,825	4,089	2,181	29,523	40,368	31,019	150,147	147,539	-	2,607	24,120	91,996	376	281	1,773	9,032,429	228,530	523,971
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	436	44	210	22	-	894	-	477	2,083	2,083	-	-	-	4,761	-	-	-	314,710	1,311	-
Disposal of Plant Systems																					
4b.1.2.1	Auxiliary Coolant (RCA)	-	12	0	0	11	-	-	5	28	28	-	-	128	-	-	-	-	5,207	257	-
4b.1.2.2	Chemical Cleaning (RCA)	-	111	47	10	-	424	-	140	733	733	-	-	-	2,260	-	-	-	149,370	2,481	-
4b.1.2.3	Chilled Water (RCA)	-	67	1	2	44	-	-	24	138	138	-	-	530	-	-	-	-	21,542	1,333	-
4b.1.2.4	Circulating Water	-	221	-	-	-	-	-	33	254	-	-	254	-	-	-	-	-	-	5,970	-
4b.1.2.5	Component Cooling (RCA)	-	429	16	35	831	-	-	239	1,551	1,551	-	-	9,938	-	-	-	-	403,572	9,324	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4b.1.2.6	CVCS/Boron Recycle/Thermal Regen	-	893	176	35	-	1,442	-	606	3,152	3,152	-	-	-	7,761	-	-	-	507,608	20,279	-
4b.1.2.7	Demineralized Water (RCA)	-	137	2	3	83	-	-	47	272	272	-	-	989	-	-	-	-	40,169	2,671	-
4b.1.2.8	Diesel Generator Services	-	97	-	-	-	-	-	14	111	-	-	111	-	-	-	-	-	-	2,525	-
4b.1.2.9	Electrical	-	2,690	-	-	-	-	-	403	3,093	-	-	3,093	-	-	-	-	-	-	70,753	-
4b.1.2.10	Electrical - Contaminated	-	436	48	11	-	442	-	226	1,162	1,162	-	-	-	2,356	-	-	-	155,755	9,634	-
4b.1.2.11	Electrical - RCA	-	3,057	440	97	-	3,977	-	1,817	9,389	9,389	-	-	-	21,188	-	-	-	1,400,488	64,407	-
4b.1.2.12	Excess Liquid Waste	-	73	10	2	-	79	-	39	204	204	-	-	-	422	-	-	-	27,915	1,573	-
4b.1.2.13	Fire Service & Sprinkler	-	319	-	-	-	-	-	48	367	-	-	367	-	-	-	-	-	-	8,380	-
4b.1.2.14	Fire Service & Sprinkler (RCA)	-	322	5	10	235	-	-	118	689	689	-	-	2,805	-	-	-	-	113,928	6,394	-
4b.1.2.15	Fuel Handling Oil	-	75	-	-	-	-	-	11	87	-	-	87	-	-	-	-	-	-	1,958	-
4b.1.2.16	HVAC - Auxiliary	-	306	7	16	383	-	-	137	850	850	-	-	4,583	-	-	-	-	186,115	6,527	-
4b.1.2.17	HVAC - Fuel Handling	-	75	2	4	101	-	-	35	217	217	-	-	1,211	-	-	-	-	49,160	1,480	-
4b.1.2.18	HVAC - Reactor	-	312	8	17	397	-	-	141	873	873	-	-	4,744	-	-	-	-	192,638	6,587	-
4b.1.2.19	Industrial Cooling Water (RCA)	-	150	5	11	257	-	-	78	501	501	-	-	3,073	-	-	-	-	124,806	3,370	-
4b.1.2.20	Instrument Air (RCA)	-	176	4	8	180	-	-	73	441	441	-	-	2,157	-	-	-	-	87,616	3,688	-
4b.1.2.21	Liquid Effluents	-	89	-	-	-	-	-	13	102	-	-	102	-	-	-	-	-	-	2,437	-
4b.1.2.22	Misc Yard Pipe	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	127	-
4b.1.2.23	Non-Nuclear Plant Drains (RCA)	-	19	0	1	19	-	-	8	46	46	-	-	226	-	-	-	-	9,166	389	-
4b.1.2.24	Nuclear Plant Drains	-	192	22	4	-	149	-	88	454	454	-	-	-	795	-	-	-	52,561	4,163	-
4b.1.2.25	Nuclear Sampling	-	64	8	1	-	55	-	31	158	158	-	-	-	290	-	-	-	19,231	1,484	-
4b.1.2.26	Radwaste Gas Handling	-	263	62	12	-	505	-	200	1,043	1,043	-	-	-	2,737	-	-	-	177,907	5,937	-
4b.1.2.27	Residual Heat Removal	-	271	61	12	-	509	-	203	1,056	1,056	-	-	-	2,706	-	-	-	179,055	6,368	-
4b.1.2.28	RX Building Spray	-	347	8	17	395	-	-	149	915	915	-	-	4,726	-	-	-	-	191,915	7,900	-
4b.1.2.29	RX Makeup Water	-	178	36	7	-	305	-	125	652	652	-	-	-	1,668	-	-	-	107,299	4,141	-
4b.1.2.30	Sanitary & Industrial Waste	-	134	-	-	-	-	-	20	154	-	-	154	-	-	-	-	-	-	3,665	-
4b.1.2.31	Service Air	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	1,219	-
4b.1.2.32	Service Air (RCA)	-	78	1	2	43	-	-	26	150	150	-	-	514	-	-	-	-	20,870	1,431	-
4b.1.2.33	Service Water	-	324	-	-	-	-	-	49	373	-	-	373	-	-	-	-	-	-	8,722	-
4b.1.2.34	Service Water (RCA)	-	196	13	26	631	-	-	149	1,015	1,015	-	-	7,548	-	-	-	-	306,527	4,487	-
4b.1.2.35	Spent Fuel Cooling	-	510	142	30	-	1,240	-	456	2,379	2,379	-	-	-	6,727	-	-	-	436,613	12,227	-
4b.1.2.36	Waste Disposal	-	618	124	25	-	1,013	-	424	2,204	2,204	-	-	-	5,514	-	-	-	356,736	14,001	-
4b.1.2	Totals	-	13,291	1,246	398	3,612	10,140	-	6,184	34,872	30,272	-	4,599	43,172	54,425	-	-	-	5,323,768	308,289	-
4b.1.3	Scaffolding in support of decommissioning	-	1,734	39	7	153	27	-	468	2,428	2,428	-	-	1,652	146	-	-	-	83,976	48,064	-
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	902	1,065	61	168	227	1,753	-	1,221	5,396	5,396	-	-	2,712	21,587	-	-	-	1,820,204	42,870	-
4b.1.4.2	Auxiliary	682	198	10	25	106	181	-	457	1,659	1,659	-	-	1,267	2,579	-	-	-	272,818	19,715	-
4b.1.4.3	Contaminated Tool Warehouse	28	6	0	1	-	8	-	18	61	61	-	-	-	113	-	-	-	9,750	762	-
4b.1.4.4	Control Complex	81	14	1	2	5	16	-	49	169	169	-	-	64	224	-	-	-	21,955	2,152	-
4b.1.4.5	Fuel Handling	376	393	6	9	158	40	-	322	1,305	1,305	-	-	1,891	456	-	-	-	114,787	18,866	-
4b.1.4.6	Hot Machine Shop	20	7	0	1	6	6	-	14	55	55	-	-	76	84	-	-	-	10,149	610	-
4b.1.4.7	Intermediate	113	17	1	2	13	11	-	66	221	221	-	-	152	159	-	-	-	19,791	2,951	-
4b.1.4.8	Old Steam Generator Recycle Facility	28	6	0	1	-	8	-	18	61	61	-	-	-	111	-	-	-	9,636	753	-
4b.1.4.9	Reactor Building Retaining Wall	0	1	0	0	1	1	-	1	5	5	-	-	13	14	-	-	-	1,759	26	-
4b.1.4	Totals	2,231	1,707	79	209	517	2,024	-	2,165	8,932	8,932	-	-	6,176	25,327	-	-	-	2,280,849	88,705	-
4b.1	Subtotal Period 4b Activity Costs	2,667	16,776	1,575	637	4,281	13,085	-	9,294	48,315	43,715	-	4,599	51,000	84,659	-	-	-	8,003,303	446,368	-
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,448	434	1,882	1,882	-	-	-	-	-	-	-	-	-	12,480
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,286	686	2,972	2,972	-	-	-	-	-	-	-	-	50,855	-
4b.2.3	Excavation of Underground Services	-	823	-	-	-	-	752	236	1,811	1,811	-	-	-	-	-	-	-	-	13,000	-
4b.2.4	Operational Equipment	-	-	18	34	603	-	-	97	753	753	-	-	11,710	-	-	-	-	292,750	32	-
4b.2.5	Decommissioning of ISFSI	-	132	95	147	-	2,096	2,674	1,286	6,430	6,430	-	-	-	30,414	-	-	-	1,706,855	13,195	10,688
4b.2	Subtotal Period 4b Additional Costs	-	955	113	182	603	2,096	7,160	2,740	13,849	13,849	-	-	11,710	30,414	-	-	-	1,999,605	77,082	23,168
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	12	-	20	18	-	121	-	41	210	210	-	-	-	194	-	-	-	11,659	38	-
4b.3.3	Small tool allowance	-	299	-	-	-	-	-	45	343	343	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	141	31	556	99	-	127	954	954	-	-	6,000	529	-	-	-	304,968	88	-
4b.3.5	On-site survey and release of 1.13 tons clean metallic waste	-	-	-	-	-	-	2	0	2	2	-	-	-	-	-	-	-	-	-	-
4b.3	Subtotal Period 4b Collateral Costs	12	299	161	48	556	220	2	213	1,510	1,510	-	-	6,000	723	-	-	-	316,627	126	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,256	-	-	-	-	-	-	314	1,570	1,570	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	1,484	148	1,632	1,632	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	3,719	-	-	-	-	-	930	4,648	4,648	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	6,472	-	-	-	-	-	971	7,443	7,443	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	134	24	-	255	-	81	493	493	-	-	-	6,248	-	-	-	124,956	204	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	3,443	516	3,960	3,960	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	1,438	144	1,581	1,581	-	-	-	-	-	-	-	-	-	-
4b.4.9	Non-Labor Overhead	-	-	-	-	-	-	1,984	298	2,282	2,282	-	-	-	-	-	-	-	-	-	-
4b.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	1,184	178	1,361	1,361	-	-	-	-	-	-	-	-	-	-
4b.4.11	Corporate A&G	-	-	-	-	-	-	3,987	598	4,585	4,585	-	-	-	-	-	-	-	-	-	-
4b.4.12	Security Staff Cost	-	-	-	-	-	-	4,709	706	5,415	5,415	-	-	-	-	-	-	-	-	-	159,464
4b.4.13	DOC Staff Cost	-	-	-	-	-	-	29,017	4,353	33,370	33,370	-	-	-	-	-	-	-	-	-	341,891
4b.4.14	Utility Staff Cost	-	-	-	-	-	-	35,412	5,312	40,724	40,724	-	-	-	-	-	-	-	-	-	602,137
4b.4	Subtotal Period 4b Period-Dependent Costs	1,256	10,191	134	24	-	255	82,657	14,548	109,064	109,064	-	-	-	6,248	-	-	-	124,956	204	1,103,493
4b.0	TOTAL PERIOD 4b COST	3,934	28,221	1,982	891	5,441	15,656	89,819	26,794	172,738	168,138	-	4,599	68,710	122,044	-	-	-	10,444,490	523,780	1,126,661
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	157	47	204	204	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	157	47	204	204	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	8,069	2,421	10,490	10,490	-	-	-	-	-	-	-	-	177,691	6,240
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	8,069	2,421	10,490	10,490	-	-	-	-	-	-	-	-	177,691	6,240
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	825	-	-	-	-	-	206	1,032	1,032	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	7	1	-	14	-	4	27	27	-	-	-	345	-	-	-	6,897	11	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	278	42	319	319	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	435	44	479	479	-	-	-	-	-	-	-	-	-	-
4f.4.7	Non-Labor Overhead	-	-	-	-	-	-	242	36	278	278	-	-	-	-	-	-	-	-	-	-
4f.4.8	Corporate A&G	-	-	-	-	-	-	485	73	558	558	-	-	-	-	-	-	-	-	-	-
4f.4.9	Security Staff Cost	-	-	-	-	-	-	624	94	717	717	-	-	-	-	-	-	-	-	-	18,514
4f.4.10	DOC Staff Cost	-	-	-	-	-	-	5,212	782	5,994	5,994	-	-	-	-	-	-	-	-	-	56,314
4f.4.11	Utility Staff Cost	-	-	-	-	-	-	4,828	724	5,552	5,552	-	-	-	-	-	-	-	-	-	73,286
4f.4	Subtotal Period 4f Period-Dependent Costs	-	825	7	1	-	14	12,104	2,005	14,957	14,957	-	-	-	345	-	-	-	6,897	11	148,114
4f.0	TOTAL PERIOD 4f COST	-	825	7	1	-	14	21,653	4,671	27,172	27,172	-	-	-	345	-	-	-	6,897	177,702	154,354
PERIOD 4 TOTALS		4,146	57,975	15,815	4,981	7,622	45,193	151,840	62,484	350,056	342,849	-	7,207	92,830	214,385	376	281	1,773	19,483,820	930,012	1,804,986
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	2,143	-	-	-	-	-	321	2,465	-	-	2,465	-	-	-	-	-	-	21,113	-
5b.1.1.2	Auxiliary	-	1,499	-	-	-	-	-	225	1,723	-	-	1,723	-	-	-	-	-	-	11,256	-
5b.1.1.3	Circulating Water Intake	-	283	-	-	-	-	-	43	326	-	-	326	-	-	-	-	-	-	1,856	-
5b.1.1.4	Combined Maintenance Shop	-	218	-	-	-	-	-	33	251	-	-	251	-	-	-	-	-	-	3,080	-
5b.1.1.5	Containment Access Runway	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	148	-
5b.1.1.6	Contaminated Tool Warehouse	-	29	-	-	-	-	-	4	33	-	-	33	-	-	-	-	-	-	425	-
5b.1.1.7	Control Complex	-	773	-	-	-	-	-	116	889	-	-	889	-	-	-	-	-	-	8,975	-
5b.1.1.8	Cooling Tower	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	242	-
5b.1.1.9	Diesel Generator	-	156	-	-	-	-	-	23	180	-	-	180	-	-	-	-	-	-	1,274	-
5b.1.1.10	Diesel Oil Storage Tanks - Buried	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	48	-
5b.1.1.11	Emergency Response Building	-	242	-	-	-	-	-	36	278	-	-	278	-	-	-	-	-	-	3,445	-

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Demolition of Remaining Site Buildings (continued)																					
5b.1.1.12	Flex Storage Building	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	626	-
5b.1.1.13	Fuel Handling	-	554	-	-	-	-	-	83	637	-	-	637	-	-	-	-	-	-	6,825	-
5b.1.1.14	Hot Machine Shop	-	70	-	-	-	-	-	11	81	-	-	81	-	-	-	-	-	-	874	-
5b.1.1.15	Intermediate	-	813	-	-	-	-	-	122	935	-	-	935	-	-	-	-	-	-	7,824	-
5b.1.1.16	Misc Site Concrete Pads	-	698	-	-	-	-	-	105	803	-	-	803	-	-	-	-	-	-	4,169	-
5b.1.1.17	Misc Site Structures	-	2,666	-	-	-	-	-	400	3,066	-	-	3,066	-	-	-	-	-	-	42,088	-
5b.1.1.18	Old Steam Generator Recycle Facility	-	117	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	693	-
5b.1.1.19	Reactor Building Retaining Wall	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	54	-
5b.1.1.20	Service	-	231	-	-	-	-	-	35	265	-	-	265	-	-	-	-	-	-	2,272	-
5b.1.1.21	Service Water Intake Pumphouse	-	220	-	-	-	-	-	33	253	-	-	253	-	-	-	-	-	-	1,406	-
5b.1.1.22	Site Paving	-	642	-	-	-	-	-	96	739	-	-	739	-	-	-	-	-	-	9,548	-
5b.1.1.23	Site Piping, Fencing & Rail	-	751	-	-	-	-	-	113	864	-	-	864	-	-	-	-	-	-	10,989	-
5b.1.1.24	Site Tank Pads	-	190	-	-	-	-	-	28	218	-	-	218	-	-	-	-	-	-	1,128	-
5b.1.1.25	Transformer Yard	-	116	-	-	-	-	-	17	133	-	-	133	-	-	-	-	-	-	689	-
5b.1.1.26	Turbine	-	1,525	-	-	-	-	-	229	1,754	-	-	1,754	-	-	-	-	-	-	26,458	-
5b.1.1.27	Turbine Pedestal	-	307	-	-	-	-	-	46	353	-	-	353	-	-	-	-	-	-	1,839	-
5b.1.1.28	Water Treatment	-	206	-	-	-	-	-	31	237	-	-	237	-	-	-	-	-	-	2,509	-
5b.1.1	Totals	-	14,569	-	-	-	-	-	2,185	16,754	-	-	16,754	-	-	-	-	-	-	171,854	-
Site Closeout Activities																					
5b.1.2	BackFill Site	-	968	-	-	-	-	-	145	1,113	-	-	1,113	-	-	-	-	-	-	1,720	-
5b.1.3	Grade & landscape site	-	199	-	-	-	-	-	30	228	-	-	228	-	-	-	-	-	-	625	-
5b.1.4	Final report to NRC	-	-	-	-	-	-	210	32	242	242	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	15,735	-	-	-	-	210	2,392	18,337	242	-	18,095	-	-	-	-	-	-	174,200	1,560
Period 5b Additional Costs																					
5b.2.1	Concrete Crushing	-	920	-	-	-	-	11	140	1,071	-	-	1,071	-	-	-	-	-	-	4,751	-
5b.2.2	Demolition of ISFSI	-	3,295	-	-	-	-	58	503	3,856	-	-	3,856	-	-	-	-	-	-	32,435	160
5b.2.3	Circ Water Cofferdam	-	233	-	-	-	-	-	35	268	-	-	268	-	-	-	-	-	-	1,936	-
5b.2.4	Service Water Cofferdam	-	319	-	-	-	-	-	-	319	-	-	319	-	-	-	-	-	-	2,714	-
5b.2.5	Construction Debris	-	-	-	-	-	-	341	51	392	-	-	392	-	-	-	-	-	-	-	-
5b.2	Subtotal Period 5b Additional Costs	-	4,767	-	-	-	-	410	729	5,906	-	-	5,906	-	-	-	-	-	-	41,836	160
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	153	-	-	-	-	-	23	176	-	-	176	-	-	-	-	-	-	-	-
5b.3.2	Non-Labor Overhead	-	-	-	-	-	-	135	20	156	-	-	156	-	-	-	-	-	-	-	-
5b.3.3	Corporate A&G	-	-	-	-	-	-	539	81	620	-	-	620	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	153	-	-	-	-	674	124	951	-	-	951	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	7,278	-	-	-	-	-	1,092	8,369	-	-	8,369	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	376	56	432	-	-	432	-	-	-	-	-	-	-	-
5b.4.5	Security Staff Cost	-	-	-	-	-	-	1,689	253	1,942	-	-	1,942	-	-	-	-	-	-	-	50,126
5b.4.6	DOC Staff Cost	-	-	-	-	-	-	13,174	1,976	15,150	-	-	15,150	-	-	-	-	-	-	-	142,023
5b.4.7	Utility Staff Cost	-	-	-	-	-	-	5,524	829	6,353	-	-	6,353	-	-	-	-	-	-	-	81,454
5b.4	Subtotal Period 5b Period-Dependent Costs	-	7,278	-	-	-	-	20,763	4,206	32,247	-	-	32,247	-	-	-	-	-	-	-	273,603
5b.0	TOTAL PERIOD 5b COST	-	27,932	-	-	-	-	22,057	7,451	57,440	242	-	57,199	-	-	-	-	-	-	216,035	275,323
PERIOD 5 TOTALS		-	27,932	-	-	-	-	22,057	7,451	57,440	242	-	57,199	-	-	-	-	-	-	216,035	275,323
TOTAL COST TO DECOMMISSION		**9,944**	**97,401**	**16,259**	**5,242**	**7,622**	**47,114**	**882,813**	**178,833**	**1,245,229**	**794,764**	**384,354**	**66,111**	**92,830**	**225,694**	**376**	**281**	**1,773**	**19,810,450**	**1,244,864**	**11,099,000**

Table D
Virgil C. Summer Nuclear Station
SAFSTOR-1 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours

TOTAL COST TO DECOMMISSION WITH 16.77% CONTINGENCY:	$1,245,229	thousands of 2016 dollars
TOTAL NRC LICENSE TERMINATION COST IS 63.82% OR:	$794,764	thousands of 2016 dollars
SPENT FUEL MANAGEMENT COST IS 30.87% OR:	$384,354	thousands of 2016 dollars
NON-NUCLEAR DEMOLITION COST IS 5.31% OR:	$66,111	thousands of 2016 dollars
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	226,350	cubic feet
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	1,773	cubic feet
TOTAL SCRAP METAL REMOVED:	52,852	tons
TOTAL CRAFT LABOR REQUIREMENTS:	1,244,864	man-hours

End Notes:
n/a - indicates that this activity not charged as decommissioning expense.
a - indicates that this activity performed by decommissioning staff.
0 - indicates that this value is less than 0.5 but is non-zero.
a cell containing " - " indicates a zero value

APPENDIX E

DETAILED COST ANALYSIS

SAFSTOR-2

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	353	106	459	459	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	269	40	310	310	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	202	30	232	232	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	417	63	480	480	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	673	101	774	774	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
1a.1.16.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	662	99	762	762	-	-	-	-	-	-	-	-	-	4,920
1a.1.16.2	Plant systems	-	-	-	-	-	-	561	84	645	645	-	-	-	-	-	-	-	-	-	4,167
1a.1.16.3	Plant structures and buildings	-	-	-	-	-	-	420	63	483	483	-	-	-	-	-	-	-	-	-	3,120
1a.1.16.4	Waste management	-	-	-	-	-	-	269	40	310	310	-	-	-	-	-	-	-	-	-	2,000
1a.1.16.5	Facility and site dormancy	-	-	-	-	-	-	269	40	310	310	-	-	-	-	-	-	-	-	-	2,000
1a.1.16	Total	-	-	-	-	-	-	2,182	327	2,509	2,509	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.17.1	Plant systems	-	-	-	-	-	-	159	24	183	183	-	-	-	-	-	-	-	-	-	1,183
1a.1.17.2	Facility closeout & dormancy	-	-	-	-	-	-	162	24	186	186	-	-	-	-	-	-	-	-	-	1,200
1a.1.17	Total	-	-	-	-	-	-	321	48	369	369	-	-	-	-	-	-	-	-	-	2,383
1a.1.18	Procure vacuum drying system	-	-	-	-	-	-	13	2	15	15	-	-	-	-	-	-	-	-	-	100
1a.1.19	Drain/de-energize non-cont. systems									a											
1a.1.20	Drain & dry NSSS									a											
1a.1.21	Drain/de-energize contaminated systems									a											
1a.1.22	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,185	831	6,016	6,016	-	-	-	-	-	-	-	-	-	35,890
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	804	121	924	-	924	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	804	121	924	-	924	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	3,275	327	3,602	3,602	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	7,350	735	8,085	8,085	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	643	643	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	707	-	-	-	-	-	106	813	813	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	2	-	25	-	8	48	48	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,876	281	2,158	2,158	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,142	114	1,256	1,256	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,009	101	1,110	-	1,110	-	-	-	-	-	-	-	-	-
1a.4.9	Non-Labor Overhead	-	-	-	-	-	-	1,312	197	1,509	1,509	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	801	120	921	-	921	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	100	15	115	-	115	-	-	-	-	-	-	-	-	-
1a.4.12	Corporate A&G	-	-	-	-	-	-	2,804	421	3,224	3,224	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	12,906	1,936	14,842	14,842	-	-	-	-	-	-	-	-	-	381,686
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	24,505	3,676	28,180	28,180	-	-	-	-	-	-	-	-	-	423,400
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,221	13	2	-	25	57,080	8,166	66,507	64,361	2,146	-	-	610	-	-	-	12,190	20	805,086
1a.0	TOTAL PERIOD 1a COST	-	1,221	13	2	-	25	63,069	9,117	73,448	70,377	3,071	-	-	610	-	-	-	12,190	20	840,976

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	986	-	-	-	-	-	-	493	1,480	1,480	-	-	-	-	-	-	-	-	23,680	-
1b.1.1.2	Auxiliary	728	-	-	-	-	-	-	364	1,091	1,091	-	-	-	-	-	-	-	-	17,334	-
1b.1.1.3	Contaminated Tool Warehouse	28	-	-	-	-	-	-	14	41	41	-	-	-	-	-	-	-	-	640	-
1b.1.1.4	Control Complex	79	-	-	-	-	-	-	40	119	119	-	-	-	-	-	-	-	-	1,855	-
1b.1.1.5	Fuel Handling	373	-	-	-	-	-	-	186	559	559	-	-	-	-	-	-	-	-	9,025	-
1b.1.1.6	Hot Machine Shop	19	-	-	-	-	-	-	10	29	29	-	-	-	-	-	-	-	-	451	-
1b.1.1.7	Intermediate	110	-	-	-	-	-	-	55	165	165	-	-	-	-	-	-	-	-	2,580	-
1b.1.1.8	Old Steam Generator Recycle Facility	27	-	-	-	-	-	-	14	41	41	-	-	-	-	-	-	-	-	632	-
1b.1.1	Totals	2,350	-	-	-	-	-	-	1,175	3,526	3,526	-	-	-	-	-	-	-	-	56,197	-
1b.1	Subtotal Period 1b Activity Costs	2,350	-	-	-	-	-	-	1,175	3,526	3,526	-	-	-	-	-	-	-	-	56,197	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	946	-	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	196	-	126	112	-	772	-	321	1,527	1,527	-	-	-	1,240	-	-	-	74,407	242	-
1b.3.4	Small tool allowance	-	37	-	-	-	-	-	6	43	43	-	-	-	-	-	-	-	-	-	-
1b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	341	51	392	-	392	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,143	37	126	112	-	772	341	519	3,049	2,657	392	-	-	1,240	-	-	-	74,407	242	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,129	-	-	-	-	-	-	282	1,411	1,411	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	825	83	908	908	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	399	-	-	-	-	-	100	498	498	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	178	-	-	-	-	-	27	205	205	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	16	3	-	30	-	10	59	59	-	-	-	743	-	-	-	14,869	24	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	473	71	544	544	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	169	17	186	186	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	254	25	280	-	280	-	-	-	-	-	-	-	-	-
1b.4.10	Non-Labor Overhead	-	-	-	-	-	-	331	50	380	380	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	232	-	232	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	25	4	29	-	29	-	-	-	-	-	-	-	-	-
1b.4.13	Corporate A&G	-	-	-	-	-	-	707	106	813	813	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,253	488	3,741	3,741	-	-	-	-	-	-	-	-	-	96,206
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,177	926	7,103	7,103	-	-	-	-	-	-	-	-	-	106,720
1b.4	Subtotal Period 1b Period-Dependent Costs	1,129	577	16	3	-	30	12,416	2,218	16,389	15,848	541	-	-	743	-	-	-	14,869	24	202,926
1b.0	TOTAL PERIOD 1b COST	4,622	614	142	115	-	802	12,757	3,912	22,964	22,031	933	-	-	1,984	-	-	-	89,276	56,463	202,926
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	400	-	-	-	-	-	60	460	460	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	28	-	-	-	-	-	4	32	32	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	15,343	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	79	12	90	90	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	427	-	-	-	-	811	296	1,535	1,535	-	-	-	-	-	-	-	-	19,043	583
Period 1c Additional Costs																					
1c.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,358	1,704	13,062	13,062	-	-	-	-	-	-	-	-	-	-
1c.2	Subtotal Period 1c Additional Costs	-	-	-	-	-	-	11,358	1,704	13,062	13,062	-	-	-	-	-	-	-	-	-	-
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	201	-	129	115	-	791	-	328	1,565	1,565	-	-	-	1,271	-	-	-	76,282	248	-
1c.3.3	Small tool allowance	-	3	-	-	-	-	-	0	3	3	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	271	41	312	-	312	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	201	3	129	115	-	791	271	369	1,880	1,568	312	-	-	1,271	-	-	-	76,282	248	-

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	834	83	918	918	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	223	-	-	-	-	-	56	279	279	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	180	-	-	-	-	-	27	207	207	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	6	-	2	12	12	-	-	-	155	-	-	-	3,106	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	478	72	550	550	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	171	17	188	188	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	257	26	283	-	283	-	-	-	-	-	-	-	-	-
1c.4.9	Non-Labor Overhead	-	-	-	-	-	-	334	50	384	384	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	204	31	235	-	235	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	26	4	29	-	29	-	-	-	-	-	-	-	-	-
1c.4.12	Corporate A&G	-	-	-	-	-	-	714	107	821	821	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	3,288	493	3,782	3,782	-	-	-	-	-	-	-	-	-	97,251
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,244	937	7,180	7,180	-	-	-	-	-	-	-	-	-	107,880
1c.4	Subtotal Period 1c Period-Dependent Costs	-	403	3	1	-	6	12,551	1,904	14,869	14,322	547	-	-	155	-	-	-	3,106	5	205,131
1c.0	TOTAL PERIOD 1c COST	201	833	133	116	-	797	24,992	4,273	31,344	30,485	859	-	-	1,427	-	-	-	79,388	19,296	205,715
PERIOD 1 TOTALS		4,823	2,668	288	233	-	1,624	100,818	17,303	127,756	122,893	4,863	-	-	4,020	-	-	-	180,855	75,779	1,249,616
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	1,010	151	1,161	1,161	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	629	157	787	787	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	1,639	309	1,948	1,948	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	32,003	4,800	36,804	-	36,804	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	32,003	4,800	36,804	-	36,804	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	2,728	273	3,001	2,893	108	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	929	-	-	-	-	-	232	1,161	1,161	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	22	4	-	42	-	13	82	82	-	-	-	1,035	-	-	-	20,701	34	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,688	253	1,941	971	971	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	1,286	129	1,414	1,414	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,843	184	2,028	-	2,028	-	-	-	-	-	-	-	-	-
2a.4.8	Non-Labor Overhead	-	-	-	-	-	-	1,037	156	1,193	264	928	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	3,603	540	4,143	-	4,143	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	451	68	519	-	519	-	-	-	-	-	-	-	-	-
2a.4.11	Corporate A&G	-	-	-	-	-	-	2,454	368	2,822	625	2,197	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	30,783	4,617	35,401	6,825	28,576	-	-	-	-	-	-	-	-	816,309
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	22,042	3,306	25,349	5,346	20,003	-	-	-	-	-	-	-	-	370,623
2a.4	Subtotal Period 2a Period-Dependent Costs	-	929	22	4	-	42	67,916	10,140	79,053	19,580	59,473	-	-	1,035	-	-	-	20,701	34	1,186,931
2a.0	TOTAL PERIOD 2a COST	-	929	22	4	-	42	101,558	15,249	117,804	21,528	96,277	-	-	1,035	-	-	-	20,701	34	1,186,931
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	9,301	1,395	10,696	10,696	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	5,796	1,449	7,245	7,245	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	15,097	2,844	17,942	17,942	-	-	-	-	-	-	-	-	-	-
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	73,372	11,006	84,378	-	84,378	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	73,372	11,006	84,378	-	84,378	-	-	-	-	-	-	-	-	-

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	25,124	2,512	27,636	26,640	996	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	4,148	-	-	-	-	-	1,037	5,185	5,185	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	98	17	-	187	-	59	361	361	-	-	-	4,579	-	-	-	91,579	149	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	7,774	1,166	8,940	8,940	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	11,307	1,131	12,438	12,438	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	5,530	553	6,083	-	6,083	-	-	-	-	-	-	-	-	-
2b.4.8	Non-Labor Overhead	-	-	-	-	-	-	3,869	580	4,449	2,433	2,016	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	4,155	623	4,779	-	4,779	-	-	-	-	-	-	-	-	-
2b.4.10	Corporate A&G	-	-	-	-	-	-	9,155	1,373	10,528	5,757	4,771	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	121,421	18,213	139,634	62,852	76,783	-	-	-	-	-	-	-	-	3,629,280
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	81,659	12,249	93,908	49,232	44,676	-	-	-	-	-	-	-	-	1,382,583
2b.4	Subtotal Period 2b Period-Dependent Costs	-	4,148	98	17	-	187	269,993	39,497	313,941	173,838	140,103	-	-	4,579	-	-	-	91,579	149	5,011,863
2b.0	TOTAL PERIOD 2b COST	-	4,148	98	17	-	187	358,463	53,347	416,260	191,780	224,480	-	-	4,579	-	-	-	91,579	149	5,011,863
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	1,530	229	1,759	1,759	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	953	238	1,192	1,192	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	2,483	468	2,951	2,951	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	3,983	398	4,381	4,381	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	642	-	-	-	-	-	160	802	802	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	15	3	-	28	-	9	55	55	-	-	-	694	-	-	-	13,871	23	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	1,279	192	1,470	1,470	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	1,714	171	1,885	1,885	-	-	-	-	-	-	-	-	-	-
2c.4.7	Non-Labor Overhead	-	-	-	-	-	-	348	52	400	400	-	-	-	-	-	-	-	-	-	-
2c.4.8	Corporate A&G	-	-	-	-	-	-	823	124	947	947	-	-	-	-	-	-	-	-	-	-
2c.4.9	Security Staff Cost	-	-	-	-	-	-	8,988	1,348	10,337	10,337	-	-	-	-	-	-	-	-	-	213,171
2c.4.10	Utility Staff Cost	-	-	-	-	-	-	7,041	1,056	8,097	8,097	-	-	-	-	-	-	-	-	-	124,350
2c.4	Subtotal Period 2c Period-Dependent Costs	-	642	15	3	-	28	24,176	3,511	28,374	28,374	-	-	-	694	-	-	-	13,871	23	337,521
2c.0	TOTAL PERIOD 2c COST	-	642	15	3	-	28	26,658	3,979	31,325	31,325	-	-	-	694	-	-	-	13,871	23	337,521
PERIOD 2 TOTALS		-	5,719	135	24	-	257	486,679	72,575	565,389	244,632	320,757	-	-	6,308	-	-	-	126,151	206	6,536,315
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	175	26	201	201	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	1,010	151	1,161	1,161	-	-	-	-	-	-	-	-	-	7,500
3a.1.7	Perform SER and EA	-	-	-	-	-	-	417	63	480	480	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	673	101	774	774	-	-	-	-	-	-	-	-	-	5,000
3a.1.9	Prepare/submit License Termination Plan	-	-	-	-	-	-	551	83	634	634	-	-	-	-	-	-	-	-	-	4,096
3a.1.10	Receive NRC approval of termination plan									a											
Activity Specifications																					
3a.1.11.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	992	149	1,141	1,027	-	114	-	-	-	-	-	-	-	7,370
3a.1.11.2	Plant systems	-	-	-	-	-	-	561	84	645	581	-	65	-	-	-	-	-	-	-	4,167
3a.1.11.3	Reactor internals	-	-	-	-	-	-	956	143	1,099	1,099	-	-	-	-	-	-	-	-	-	7,100
3a.1.11.4	Reactor vessel	-	-	-	-	-	-	875	131	1,006	1,006	-	-	-	-	-	-	-	-	-	6,500
3a.1.11.5	Biological shield	-	-	-	-	-	-	67	10	77	77	-	-	-	-	-	-	-	-	-	500
3a.1.11.6	Steam generators	-	-	-	-	-	-	420	63	483	483	-	-	-	-	-	-	-	-	-	3,120
3a.1.11.7	Reinforced concrete	-	-	-	-	-	-	215	32	248	124	-	124	-	-	-	-	-	-	-	1,600

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Activity Specifications (continued)																					
3a.1.11.8	Main Turbine	-	-	-	-	-	-	54	8	62	-	-	62	-	-	-	-	-	-	-	400
3a.1.11.9	Main Condensers	-	-	-	-	-	-	54	8	62	-	-	62	-	-	-	-	-	-	-	400
3a.1.11.10	Plant structures & buildings	-	-	-	-	-	-	420	63	483	242	-	242	-	-	-	-	-	-	-	3,120
3a.1.11.11	Waste management	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
3a.1.11.12	Facility & site closeout	-	-	-	-	-	-	121	18	139	70	-	70	-	-	-	-	-	-	-	900
3a.1.11	Total	-	-	-	-	-	-	5,355	803	6,158	5,421	-	738	-	-	-	-	-	-	-	39,777
Planning & Site Preparations																					
3a.1.12	Prepare dismantling sequence	-	-	-	-	-	-	323	48	372	372	-	-	-	-	-	-	-	-	-	2,400
3a.1.13	Plant prep. & temp. svces	-	-	-	-	-	-	3,200	480	3,680	3,680	-	-	-	-	-	-	-	-	-	-
3a.1.14	Design water clean-up system	-	-	-	-	-	-	188	28	217	217	-	-	-	-	-	-	-	-	-	1,400
3a.1.15	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.16	Procure casks/liners & containers	-	-	-	-	-	-	166	25	190	190	-	-	-	-	-	-	-	-	-	1,230
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	15,288	2,293	17,581	16,844	-	738	-	-	-	-	-	-	-	72,703
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	3,640	1,092	4,733	4,733	-	-	-	-	-	-	-	-	22,800	8,812
3a.2	Subtotal Period 3a Additional Costs	-	-	-	-	-	-	3,640	1,092	4,733	4,733	-	-	-	-	-	-	-	-	22,800	8,812
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	585	58	643	643	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	450	-	-	-	-	-	112	562	562	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	707	-	-	-	-	-	106	813	813	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	2	-	21	-	7	41	41	-	-	-	514	-	-	-	10,287	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,876	281	2,158	2,158	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	371	37	408	408	-	-	-	-	-	-	-	-	-	-
3a.4.8	Non-Labor Overhead	-	-	-	-	-	-	948	142	1,090	1,090	-	-	-	-	-	-	-	-	-	-
3a.4.9	Corporate A&G	-	-	-	-	-	-	1,713	257	1,969	1,969	-	-	-	-	-	-	-	-	-	-
3a.4.10	Security Staff Cost	-	-	-	-	-	-	1,925	289	2,213	2,213	-	-	-	-	-	-	-	-	-	65,179
3a.4.11	Utility Staff Cost	-	-	-	-	-	-	15,147	2,272	17,419	17,419	-	-	-	-	-	-	-	-	-	258,629
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,156	11	2	-	21	22,564	3,562	27,316	27,316	-	-	-	514	-	-	-	10,287	17	323,807
3a.0	TOTAL PERIOD 3a COST	-	1,156	11	2	-	21	41,492	6,947	49,630	48,892	-	738	-	514	-	-	-	10,287	22,817	405,322
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	637	96	733	660	-	73	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	337	50	387	387	-	-	-	-	-	-	-	-	-	2,500
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	182	27	209	52	-	157	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	135	20	155	155	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	3,630
3b.1.1.8	Facility closeout	-	-	-	-	-	-	162	24	186	93	-	93	-	-	-	-	-	-	-	1,200
3b.1.1.9	Missile shields	-	-	-	-	-	-	61	9	70	70	-	-	-	-	-	-	-	-	-	450
3b.1.1.10	Biological shield	-	-	-	-	-	-	162	24	186	186	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.11	Steam generators	-	-	-	-	-	-	619	93	712	712	-	-	-	-	-	-	-	-	-	4,600
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	135	20	155	77	-	77	-	-	-	-	-	-	-	1,000
3b.1.1.13	Main Turbine	-	-	-	-	-	-	210	32	242	-	-	242	-	-	-	-	-	-	-	1,560
3b.1.1.14	Main Condensers	-	-	-	-	-	-	210	32	242	-	-	242	-	-	-	-	-	-	-	1,560
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	368	55	423	380	-	42	-	-	-	-	-	-	-	2,730
3b.1.1.16	Reactor building	-	-	-	-	-	-	368	55	423	380	-	42	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	4,341	651	4,992	4,024	-	968	-	-	-	-	-	-	-	32,243
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	4,341	651	4,992	4,024	-	968	-	-	-	-	-	-	-	32,243
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	946	-	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	946	1,200	-	-	-	-	1,323	520	3,989	3,989	-	-	-	-	-	-	-	-	-	-

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	29	-	-	-	-	-	-	7	37	37	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	307	31	338	338	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	251	-	-	-	-	-	63	314	314	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	358	-	-	-	-	-	54	412	412	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	1	-	12	-	4	23	23	-	-	-	295	-	-	-	5,898	10	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	951	143	1,094	1,094	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	188	19	207	207	-	-	-	-	-	-	-	-	-	-
3b.4.9	Non-Labor Overhead	-	-	-	-	-	-	480	72	552	552	-	-	-	-	-	-	-	-	-	-
3b.4.10	Corporate A&G	-	-	-	-	-	-	868	130	998	998	-	-	-	-	-	-	-	-	-	-
3b.4.11	Security Staff Cost	-	-	-	-	-	-	975	146	1,122	1,122	-	-	-	-	-	-	-	-	-	33,036
3b.4.12	DOC Staff Cost	-	-	-	-	-	-	5,334	800	6,135	6,135	-	-	-	-	-	-	-	-	-	59,200
3b.4.13	Utility Staff Cost	-	-	-	-	-	-	7,677	1,152	8,829	8,829	-	-	-	-	-	-	-	-	-	131,086
3b.4	Subtotal Period 3b Period-Dependent Costs	29	609	6	1	-	12	16,782	2,620	20,060	20,060	-	-	-	295	-	-	-	5,898	10	223,321
3b.0	TOTAL PERIOD 3b COST	975	1,809	6	1	-	12	22,445	3,792	29,041	28,073	-	968	-	295	-	-	-	5,898	10	255,564
PERIOD 3 TOTALS		975	2,966	17	3	-	33	63,937	10,739	78,671	76,965	-	1,705	-	809	-	-	-	16,185	22,826	660,886
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Reactor Coolant Piping	14	51	12	4	64	97	-	55	297	297	-	-	281	297	-	-	-	65,195	1,538	-
4a.1.1.2	Pressurizer Relief Tank	4	15	6	2	30	42	-	22	120	120	-	-	133	133	-	-	-	29,424	480	-
4a.1.1.3	Reactor Coolant Pumps & Motors	12	51	43	152	-	245	-	107	611	611	-	-	-	3,322	-	-	-	605,445	2,001	80
4a.1.1.4	Pressurizer	7	39	437	151	-	211	-	132	976	976	-	-	-	2,862	-	-	-	190,272	1,501	1,500
4a.1.1.5	Steam Generators	47	5,645	2,755	1,639	-	2,062	-	2,472	14,619	14,619	-	-	-	27,948	-	-	-	2,412,202	8,301	2,250
4a.1.1.6	Retired Steam Generator Units	-	-	2,755	1,639	-	2,062	-	1,037	7,493	7,493	-	-	-	27,948	-	-	-	2,250,000	-	2,250
4a.1.1.7	CRDMs/ICIs/Service Structure Removal	24	165	207	11	57	291	-	157	913	913	-	-	753	2,604	-	-	-	130,284	4,687	-
4a.1.1.8	Reactor Vessel Internals	35	4,750	5,747	230	-	3,703	221	6,959	21,645	21,645	-	-	-	1,204	751	281	-	219,076	17,873	873
4a.1.1.9	Vessel & Internals GTCC Disposal	-	-	-	-	-	11,639	-	1,746	13,384	13,384	-	-	-	-	-	-	1,773	363,061	-	-
4a.1.1.10	Reactor Vessel	-	7,308	1,157	90	-	6,533	221	9,093	24,402	24,402	-	-	-	7,625	-	-	-	769,200	17,873	873
4a.1.1	Totals	143	18,024	13,118	3,919	152	26,884	441	21,779	84,461	84,461	-	-	1,167	73,942	751	281	1,773	7,034,158	54,256	7,827
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	233	158	29	469	397	-	248	1,533	1,533	-	-	5,060	2,113	-	-	-	367,369	5,959	-
4a.1.3	Main Condensers	-	756	184	34	547	463	-	410	2,395	2,395	-	-	5,901	2,464	-	-	-	428,414	19,204	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor	-	377	-	-	-	-	-	57	434	434	-	-	-	-	-	-	-	-	3,705	-
4a.1.4.2	Auxiliary	-	164	-	-	-	-	-	25	189	189	-	-	-	-	-	-	-	-	1,189	-
4a.1.4.3	Fuel Handling	-	57	-	-	-	-	-	9	66	66	-	-	-	-	-	-	-	-	648	-
4a.1.4	Totals	-	599	-	-	-	-	-	90	689	689	-	-	-	-	-	-	-	-	5,542	-
Disposal of Plant Systems																					
4a.1.5.1	Aux Boiler Steam & Reheat	-	35	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	938	-
4a.1.5.2	Aux Boiler Steam & Reheat (RCA)	-	83	4	9	225	-	-	56	379	379	-	-	2,692	-	-	-	-	109,340	1,764	-
4a.1.5.3	Auxiliary Coolant	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	665	-
4a.1.5.4	Breathing Air (RCA)	-	24	0	0	11	-	-	8	43	43	-	-	131	-	-	-	-	5,326	451	-
4a.1.5.5	Carbon Dioxide - Gen Gas & Vents	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	140	-
4a.1.5.6	Chemical Cleaning	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	244	-
4a.1.5.7	Chilled Water	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	2,963	-
4a.1.5.8	Component Cooling	-	72	-	-	-	-	-	11	83	-	-	83	-	-	-	-	-	-	1,927	-
4a.1.5.9	Condensate	-	214	-	-	-	-	-	32	246	-	-	246	-	-	-	-	-	-	5,692	-
4a.1.5.10	Condensate Demin	-	35	-	-	-	-	-	5	40	-	-	40	-	-	-	-	-	-	923	-
4a.1.5.11	Condenser Air Removal	-	85	-	-	-	-	-	13	97	-	-	97	-	-	-	-	-	-	2,274	-
4a.1.5.12	Condenser Cleaning	-	12	-	-	-	-	-	2	14	-	-	14	-	-	-	-	-	-	317	-
4a.1.5.13	Demineralized Water	-	39	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	1,003	-
4a.1.5.14	Emergency Feedwater	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	654	-
4a.1.5.15	Emergency Feedwater (RCA)	-	43	1	3	72	-	-	22	141	141	-	-	855	-	-	-	-	34,715	984	-
4a.1.5.16	Extraction Steam	-	70	-	-	-	-	-	10	80	-	-	80	-	-	-	-	-	-	1,882	-
4a.1.5.17	Feedwater	-	299	-	-	-	-	-	45	344	-	-	344	-	-	-	-	-	-	8,000	-
4a.1.5.18	Feedwater (RCA)	-	51	3	6	149	-	-	36	245	245	-	-	1,782	-	-	-	-	72,373	1,161	-
4a.1.5.19	Filtered & Raw Water Treatment	-	159	-	-	-	-	-	24	183	-	-	183	-	-	-	-	-	-	4,169	-

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4a.1.5.20	Gland Sealing Steam	-	28	-	-	-	-	-	4	32	-	-	32	-	-	-	-	-	-	773	-
4a.1.5.21	Heater Drains & Vents	-	160	-	-	-	-	-	24	184	-	-	184	-	-	-	-	-	-	4,322	-
4a.1.5.22	HVAC - Control Bldg	-	34	-	-	-	-	-	5	39	-	-	39	-	-	-	-	-	-	954	-
4a.1.5.23	HVAC - Intermediate	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	823	-
4a.1.5.24	HVAC - Misc Bldgs	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	1,436	-
4a.1.5.25	HVAC - Turbine	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,876	-
4a.1.5.26	Hydrogen	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	106	-
4a.1.5.27	Hydrogen - Plant (NSSS H & O2)	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	206	-
4a.1.5.28	Instrument Air	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,040	-
4a.1.5.29	Lube Oil	-	53	-	-	-	-	-	8	60	-	-	60	-	-	-	-	-	-	1,390	-
4a.1.5.30	Main Steam	-	154	-	-	-	-	-	23	177	-	-	177	-	-	-	-	-	-	4,133	-
4a.1.5.31	Main Steam (RCA)	-	65	3	5	131	-	-	37	241	241	-	-	1,563	-	-	-	-	63,494	1,396	-
4a.1.5.32	Main Steam Dump	-	23	-	-	-	-	-	4	27	-	-	27	-	-	-	-	-	-	639	-
4a.1.5.33	Nitrogen & Oxygen	-	16	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	404	-
4a.1.5.34	Nitrogen & Oxygen (RCA)	-	56	1	1	34	-	-	19	112	112	-	-	404	-	-	-	-	16,411	1,055	-
4a.1.5.35	Non-Nuclear Plant Drains	-	56	-	-	-	-	-	8	64	-	-	64	-	-	-	-	-	-	1,515	-
4a.1.5.36	Nuclear Blowdown Processing	-	224	5	10	240	-	-	94	573	573	-	-	2,868	-	-	-	-	116,458	5,018	-
4a.1.5.37	PASS - H2 Removal	-	31	1	2	41	-	-	14	89	89	-	-	486	-	-	-	-	19,748	745	-
4a.1.5.38	Reactor Coolant	-	198	150	27	-	1,113	-	347	1,834	1,834	-	-	-	5,914	-	-	-	391,758	4,793	-
4a.1.5.39	Reheat Steam	-	82	-	-	-	-	-	12	95	-	-	95	-	-	-	-	-	-	2,195	-
4a.1.5.40	RX Leak Rate Testing	-	11	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	295	-
4a.1.5.41	Safety Injection	-	470	91	17	-	683	-	300	1,561	1,561	-	-	-	3,667	-	-	-	240,663	10,564	-
4a.1.5.42	Steam Gen Blowdown	-	42	-	-	-	-	-	6	48	-	-	48	-	-	-	-	-	-	1,059	-
4a.1.5.43	Steam Gen Blowdown (RCA)	-	22	0	0	9	-	-	7	39	39	-	-	109	-	-	-	-	4,425	478	-
4a.1.5.44	TB Closed Cycle Cooling	-	56	-	-	-	-	-	8	64	-	-	64	-	-	-	-	-	-	1,492	-
4a.1.5.45	TB Cycle Chem Feed	-	81	-	-	-	-	-	12	93	-	-	93	-	-	-	-	-	-	2,088	-
4a.1.5.46	TB Cycle Sampling	-	37	-	-	-	-	-	6	43	-	-	43	-	-	-	-	-	-	962	-
4a.1.5.47	Turbine Systems	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	657	-
4a.1.5	Totals	-	3,518	259	82	911	1,796	-	1,278	7,845	5,257	-	2,588	10,891	9,581	-	-	-	1,074,710	88,565	-
4a.1.6	Scaffolding in support of decommissioning	-	1,156	26	5	102	18	-	312	1,619	1,619	-	-	1,101	97	-	-	-	55,984	32,043	-
4a.1	Subtotal Period 4a Activity Costs	143	24,287	13,745	4,069	2,181	29,558	441	24,118	98,542	95,954	-	2,588	24,120	88,198	751	281	1,773	8,960,634	205,569	7,827
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,027	308	1,335	1,335	-	-	-	-	-	-	-	-	22,836	-
4a.2	Subtotal Period 4a Additional Costs	-	-	-	-	-	-	1,027	308	1,335	1,335	-	-	-	-	-	-	-	-	22,836	-
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	5	-	9	8	-	52	-	18	91	91	-	-	-	84	-	-	-	5,038	16	-
4a.3.3	Small tool allowance	-	165	-	-	-	-	-	25	190	171	-	19	-	-	-	-	-	-	-	-
4a.3.4	On-site survey and release of 27.16 tons clean metallic waste	-	-	-	-	-	-	47	5	51	51	-	-	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	5	165	9	8	-	52	47	47	333	314	-	19	-	84	-	-	-	5,038	16	-
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	64	-	-	-	-	-	-	16	80	80	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	666	67	733	733	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,646	-	-	-	-	-	412	2,058	2,058	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,830	-	-	-	-	-	425	3,255	3,255	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	71	13	-	136	-	43	263	263	-	-	-	3,338	-	-	-	66,757	109	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	1,958	294	2,252	2,252	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	646	65	710	710	-	-	-	-	-	-	-	-	-	-
4a.4.9	Non-Labor Overhead	-	-	-	-	-	-	944	142	1,086	1,086	-	-	-	-	-	-	-	-	-	-
4a.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	531	80	611	611	-	-	-	-	-	-	-	-	-	-
4a.4.11	Corporate A&G	-	-	-	-	-	-	1,897	284	2,181	2,181	-	-	-	-	-	-	-	-	-	-
4a.4.12	Security Staff Cost	-	-	-	-	-	-	2,114	317	2,431	2,431	-	-	-	-	-	-	-	-	-	71,607
4a.4.13	DOC Staff Cost	-	-	-	-	-	-	13,357	2,004	15,361	15,361	-	-	-	-	-	-	-	-	-	158,109
4a.4.14	Utility Staff Cost	-	-	-	-	-	-	16,740	2,511	19,251	19,251	-	-	-	-	-	-	-	-	-	286,429
4a.4	Subtotal Period 4a Period-Dependent Costs	64	4,477	71	13	-	136	38,854	6,658	50,272	50,272	-	-	-	3,338	-	-	-	66,757	109	516,144
4a.0	TOTAL PERIOD 4a COST	212	28,929	13,825	4,089	2,181	29,746	40,368	31,130	150,481	147,874	-	2,607	24,120	91,620	751	281	1,773	9,032,429	228,530	523,971

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	436	44	210	22	-	894	-	477	2,083	2,083	-	-	-	4,761	-	-	-	314,710	1,311	-
Disposal of Plant Systems																					
4b.1.2.1	Auxiliary Coolant (RCA)	-	12	0	0	11	-	-	5	28	28	-	-	128	-	-	-	-	5,207	257	-
4b.1.2.2	Chemical Cleaning (RCA)	-	111	47	10	-	424	-	140	733	733	-	-	-	2,260	-	-	-	149,370	2,481	-
4b.1.2.3	Chilled Water (RCA)	-	67	1	2	44	-	-	24	138	138	-	-	530	-	-	-	-	21,542	1,333	-
4b.1.2.4	Circulating Water	-	221	-	-	-	-	-	33	254	-	-	254	-	-	-	-	-	-	5,970	-
4b.1.2.5	Component Cooling (RCA)	-	429	16	35	831	-	-	239	1,551	1,551	-	-	9,938	-	-	-	-	403,572	9,324	-
4b.1.2.6	CVCS/Boron Recycle/Thermal Regen	-	893	176	35	-	1,442	-	606	3,152	3,152	-	-	-	7,761	-	-	-	507,608	20,279	-
4b.1.2.7	Demineralized Water (RCA)	-	137	2	3	83	-	-	47	272	272	-	-	989	-	-	-	-	40,169	2,671	-
4b.1.2.8	Diesel Generator Services	-	97	-	-	-	-	-	14	111	-	-	111	-	-	-	-	-	-	2,525	-
4b.1.2.9	Electrical	-	2,690	-	-	-	-	-	403	3,093	-	-	3,093	-	-	-	-	-	-	70,753	-
4b.1.2.10	Electrical - Contaminated	-	436	48	11	-	442	-	226	1,162	1,162	-	-	-	2,356	-	-	-	155,755	9,634	-
4b.1.2.11	Electrical - RCA	-	3,057	440	97	-	3,977	-	1,817	9,389	9,389	-	-	-	21,188	-	-	-	1,400,488	64,407	-
4b.1.2.12	Excess Liquid Waste	-	73	10	2	-	79	-	39	204	204	-	-	-	422	-	-	-	27,915	1,573	-
4b.1.2.13	Fire Service & Sprinkler	-	319	-	-	-	-	-	48	367	-	-	367	-	-	-	-	-	-	8,380	-
4b.1.2.14	Fire Service & Sprinkler (RCA)	-	322	5	10	235	-	-	118	689	689	-	-	2,805	-	-	-	-	113,928	6,394	-
4b.1.2.15	Fuel Handling Oil	-	75	-	-	-	-	-	11	87	-	-	87	-	-	-	-	-	-	1,958	-
4b.1.2.16	HVAC - Auxiliary	-	306	7	16	383	-	-	137	850	850	-	-	4,583	-	-	-	-	186,115	6,527	-
4b.1.2.17	HVAC - Fuel Handling	-	75	2	4	101	-	-	35	217	217	-	-	1,211	-	-	-	-	49,160	1,480	-
4b.1.2.18	HVAC - Reactor	-	312	8	17	397	-	-	141	873	873	-	-	4,744	-	-	-	-	192,638	6,587	-
4b.1.2.19	Industrial Cooling Water (RCA)	-	150	5	11	257	-	-	78	501	501	-	-	3,073	-	-	-	-	124,806	3,370	-
4b.1.2.20	Instrument Air (RCA)	-	176	4	8	180	-	-	73	441	441	-	-	2,157	-	-	-	-	87,616	3,688	-
4b.1.2.21	Liquid Effluents	-	89	-	-	-	-	-	13	102	-	-	102	-	-	-	-	-	-	2,437	-
4b.1.2.22	Misc Yard Pipe	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	127	-
4b.1.2.23	Non-Nuclear Plant Drains (RCA)	-	19	0	1	19	-	-	8	46	46	-	-	226	-	-	-	-	9,166	389	-
4b.1.2.24	Nuclear Plant Drains	-	192	22	4	-	149	-	88	454	454	-	-	-	795	-	-	-	52,561	4,163	-
4b.1.2.25	Nuclear Sampling	-	64	8	1	-	55	-	31	158	158	-	-	-	290	-	-	-	19,231	1,484	-
4b.1.2.26	Radwaste Gas Handling	-	263	62	12	-	505	-	200	1,043	1,043	-	-	-	2,737	-	-	-	177,907	5,937	-
4b.1.2.27	Residual Heat Removal	-	271	61	12	-	509	-	203	1,056	1,056	-	-	-	2,706	-	-	-	179,055	6,368	-
4b.1.2.28	RX Building Spray	-	347	8	17	395	-	-	149	915	915	-	-	4,726	-	-	-	-	191,915	7,900	-
4b.1.2.29	RX Makeup Water	-	178	36	7	-	305	-	125	652	652	-	-	-	1,668	-	-	-	107,299	4,141	-
4b.1.2.30	Sanitary & Industrial Waste	-	134	-	-	-	-	-	20	154	-	-	154	-	-	-	-	-	-	3,665	-
4b.1.2.31	Service Air	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	1,219	-
4b.1.2.32	Service Air (RCA)	-	78	1	2	43	-	-	26	150	150	-	-	514	-	-	-	-	20,870	1,431	-
4b.1.2.33	Service Water	-	324	-	-	-	-	-	49	373	-	-	373	-	-	-	-	-	-	8,722	-
4b.1.2.34	Service Water (RCA)	-	196	13	26	631	-	-	149	1,015	1,015	-	-	7,548	-	-	-	-	306,527	4,487	-
4b.1.2.35	Spent Fuel Cooling	-	510	142	30	-	1,240	-	456	2,379	2,379	-	-	-	6,727	-	-	-	436,613	12,227	-
4b.1.2.36	Waste Disposal	-	618	124	25	-	1,013	-	424	2,204	2,204	-	-	-	5,514	-	-	-	356,736	14,001	-
4b.1.2	Totals	-	13,291	1,246	398	3,612	10,140	-	6,184	34,872	30,272	-	4,599	43,172	54,425	-	-	-	5,323,768	308,289	-
4b.1.3	Scaffolding in support of decommissioning	-	1,734	39	7	153	27	-	468	2,428	2,428	-	-	1,652	146	-	-	-	83,976	48,064	-
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	902	1,065	61	168	227	1,753	-	1,221	5,396	5,396	-	-	2,712	21,587	-	-	-	1,820,204	42,870	-
4b.1.4.2	Auxiliary	682	198	10	25	106	181	-	457	1,659	1,659	-	-	1,267	2,579	-	-	-	272,818	19,715	-
4b.1.4.3	Contaminated Tool Warehouse	28	6	0	1	-	8	-	18	61	61	-	-	-	113	-	-	-	9,750	762	-
4b.1.4.4	Control Complex	81	14	1	2	5	16	-	49	169	169	-	-	64	224	-	-	-	21,955	2,152	-
4b.1.4.5	Fuel Handling	376	393	6	9	158	40	-	322	1,305	1,305	-	-	1,891	456	-	-	-	114,787	18,866	-
4b.1.4.6	Hot Machine Shop	20	7	0	1	6	6	-	14	55	55	-	-	76	84	-	-	-	10,149	610	-
4b.1.4.7	Intermediate	113	17	1	2	13	11	-	66	221	221	-	-	152	159	-	-	-	19,791	2,951	-
4b.1.4.8	Old Steam Generator Recycle Facility	28	6	0	1	-	8	-	18	61	61	-	-	-	111	-	-	-	9,636	753	-
4b.1.4.9	Reactor Building Retaining Wall	0	1	0	0	1	1	-	1	5	5	-	-	13	14	-	-	-	1,759	26	-
4b.1.4	Totals	2,231	1,707	79	209	517	2,024	-	2,165	8,932	8,932	-	-	6,176	25,327	-	-	-	2,280,849	88,705	-
4b.1	Subtotal Period 4b Activity Costs	2,667	16,776	1,575	637	4,281	13,085	-	9,294	48,315	43,715	-	4,599	51,000	84,659	-	-	-	8,003,303	446,368	-
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,448	434	1,882	1,882	-	-	-	-	-	-	-	-	-	12,480
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,286	686	2,972	2,972	-	-	-	-	-	-	-	-	50,855	-
4b.2.3	Excavation of Underground Services	-	823	-	-	-	-	752	236	1,811	1,811	-	-	-	-	-	-	-	-	13,000	-
4b.2.4	Operational Equipment	-	-	18	34	603	-	-	97	753	753	-	-	11,710	-	-	-	-	292,750	32	-
4b.2.5	Decommissioning of ISFSI	-	132	95	147	-	2,096	2,674	1,286	6,430	6,430	-	-	-	30,414	-	-	-	1,706,855	13,195	10,688
4b.2	Subtotal Period 4b Additional Costs	-	955	113	182	603	2,096	7,160	2,740	13,849	13,849	-	-	11,710	30,414	-	-	-	1,999,605	77,082	23,168

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	12	-	20	18	-	121	-	41	210	210	-	-	-	194	-	-	-	11,659	38	-
4b.3.3	Small tool allowance	-	299	-	-	-	-	-	45	343	343	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	141	31	556	99	-	127	954	954	-	-	6,000	529	-	-	-	304,968	88	-
4b.3.5	On-site survey and release of 1.13 tons clean metallic waste	-	-	-	-	-	-	2	0	2	2	-	-	-	-	-	-	-	-	-	-
4b.3	Subtotal Period 4b Collateral Costs	12	299	161	48	556	220	2	213	1,510	1,510	-	-	6,000	723	-	-	-	316,627	126	-
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,256	-	-	-	-	-	-	314	1,570	1,570	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	1,484	148	1,632	1,632	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	3,719	-	-	-	-	-	930	4,648	4,648	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	6,472	-	-	-	-	-	971	7,443	7,443	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	134	24	-	255	-	81	493	493	-	-	-	6,248	-	-	-	124,956	204	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	3,443	516	3,960	3,960	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	1,438	144	1,581	1,581	-	-	-	-	-	-	-	-	-	-
4b.4.9	Non-Labor Overhead	-	-	-	-	-	-	1,984	298	2,282	2,282	-	-	-	-	-	-	-	-	-	-
4b.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	1,184	178	1,361	1,361	-	-	-	-	-	-	-	-	-	-
4b.4.11	Corporate A&G	-	-	-	-	-	-	3,987	598	4,585	4,585	-	-	-	-	-	-	-	-	-	-
4b.4.12	Security Staff Cost	-	-	-	-	-	-	4,709	706	5,415	5,415	-	-	-	-	-	-	-	-	-	159,464
4b.4.13	DOC Staff Cost	-	-	-	-	-	-	29,017	4,353	33,370	33,370	-	-	-	-	-	-	-	-	-	341,891
4b.4.14	Utility Staff Cost	-	-	-	-	-	-	35,412	5,312	40,724	40,724	-	-	-	-	-	-	-	-	-	602,137
4b.4	Subtotal Period 4b Period-Dependent Costs	1,256	10,191	134	24	-	255	82,657	14,548	109,064	109,064	-	-	-	6,248	-	-	-	124,956	204	1,103,493
4b.0	TOTAL PERIOD 4b COST	3,934	28,221	1,982	891	5,441	15,656	89,819	26,794	172,738	168,138	-	4,599	68,710	122,044	-	-	-	10,444,490	523,780	1,126,661
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	157	47	204	204	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	157	47	204	204	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	8,069	2,421	10,490	10,490	-	-	-	-	-	-	-	-	177,691	6,240
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	8,069	2,421	10,490	10,490	-	-	-	-	-	-	-	-	177,691	6,240
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	825	-	-	-	-	-	206	1,032	1,032	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	7	1	-	14	-	4	27	27	-	-	-	345	-	-	-	6,897	11	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	278	42	319	319	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	435	44	479	479	-	-	-	-	-	-	-	-	-	-
4f.4.7	Non-Labor Overhead	-	-	-	-	-	-	242	36	278	278	-	-	-	-	-	-	-	-	-	-
4f.4.8	Corporate A&G	-	-	-	-	-	-	485	73	558	558	-	-	-	-	-	-	-	-	-	-
4f.4.9	Security Staff Cost	-	-	-	-	-	-	624	94	717	717	-	-	-	-	-	-	-	-	-	18,514
4f.4.10	DOC Staff Cost	-	-	-	-	-	-	5,212	782	5,994	5,994	-	-	-	-	-	-	-	-	-	56,314
4f.4.11	Utility Staff Cost	-	-	-	-	-	-	4,828	724	5,552	5,552	-	-	-	-	-	-	-	-	-	73,286
4f.4	Subtotal Period 4f Period-Dependent Costs	-	825	7	1	-	14	12,104	2,005	14,957	14,957	-	-	-	345	-	-	-	6,897	11	148,114
4f.0	TOTAL PERIOD 4f COST	-	825	7	1	-	14	21,653	4,671	27,172	27,172	-	-	-	345	-	-	-	6,897	177,702	154,354
PERIOD 4 TOTALS		4,146	57,975	15,815	4,981	7,622	45,416	151,840	62,595	350,390	343,183	-	7,207	92,830	214,009	751	281	1,773	19,483,820	930,012	1,804,986
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	2,143	-	-	-	-	-	321	2,465	-	-	2,465	-	-	-	-	-	-	21,113	-
5b.1.1.2	Auxiliary	-	1,499	-	-	-	-	-	225	1,723	-	-	1,723	-	-	-	-	-	-	11,256	-
5b.1.1.3	Circulating Water Intake	-	283	-	-	-	-	-	43	326	-	-	326	-	-	-	-	-	-	1,856	-
5b.1.1.4	Combined Maintenance Shop	-	218	-	-	-	-	-	33	251	-	-	251	-	-	-	-	-	-	3,080	-

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
	Demolition of Remaining Site Buildings (continued)																				
5b.1.1.5	Containment Access Runway	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	148	-
5b.1.1.6	Contaminated Tool Warehouse	-	29	-	-	-	-	-	4	33	-	-	33	-	-	-	-	-	-	425	-
5b.1.1.7	Control Complex	-	773	-	-	-	-	-	116	889	-	-	889	-	-	-	-	-	-	8,975	-
5b.1.1.8	Cooling Tower	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	242	-
5b.1.1.9	Diesel Generator	-	156	-	-	-	-	-	23	180	-	-	180	-	-	-	-	-	-	1,274	-
5b.1.1.10	Diesel Oil Storage Tanks - Buried	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	48	-
5b.1.1.11	Emergency Response Building	-	242	-	-	-	-	-	36	278	-	-	278	-	-	-	-	-	-	3,445	-
5b.1.1.12	Flex Storage Buiding	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	626	-
5b.1.1.13	Fuel Handling	-	554	-	-	-	-	-	83	637	-	-	637	-	-	-	-	-	-	6,825	-
5b.1.1.14	Hot Machine Shop	-	70	-	-	-	-	-	11	81	-	-	81	-	-	-	-	-	-	874	-
5b.1.1.15	Intermediate	-	813	-	-	-	-	-	122	935	-	-	935	-	-	-	-	-	-	7,824	-
5b.1.1.16	Misc Site Concrete Pads	-	698	-	-	-	-	-	105	803	-	-	803	-	-	-	-	-	-	4,169	-
5b.1.1.17	Misc Site Structures	-	2,666	-	-	-	-	-	400	3,066	-	-	3,066	-	-	-	-	-	-	42,088	-
5b.1.1.18	Old Steam Generator Recycle Facility	-	117	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	693	-
5b.1.1.19	Reactor Building Retaining Wall	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	54	-
5b.1.1.20	Service	-	231	-	-	-	-	-	35	265	-	-	265	-	-	-	-	-	-	2,272	-
5b.1.1.21	Service Water Intake Pumphouse	-	220	-	-	-	-	-	33	253	-	-	253	-	-	-	-	-	-	1,406	-
5b.1.1.22	Site Paving	-	642	-	-	-	-	-	96	739	-	-	739	-	-	-	-	-	-	9,548	-
5b.1.1.23	Site Piping, Fencing & Rail	-	751	-	-	-	-	-	113	864	-	-	864	-	-	-	-	-	-	10,989	-
5b.1.1.24	Site Tank Pads	-	190	-	-	-	-	-	28	218	-	-	218	-	-	-	-	-	-	1,128	-
5b.1.1.25	Transformer Yard	-	116	-	-	-	-	-	17	133	-	-	133	-	-	-	-	-	-	689	-
5b.1.1.26	Turbine	-	1,525	-	-	-	-	-	229	1,754	-	-	1,754	-	-	-	-	-	-	26,458	-
5b.1.1.27	Turbine Pedestal	-	307	-	-	-	-	-	46	353	-	-	353	-	-	-	-	-	-	1,839	-
5b.1.1.28	Water Treatment	-	206	-	-	-	-	-	31	237	-	-	237	-	-	-	-	-	-	2,509	-
5b.1.1	Totals	-	14,569	-	-	-	-	-	2,185	16,754	-	-	16,754	-	-	-	-	-	-	171,854	-
	Site Closeout Activities																				
5b.1.2	BackFill Site	-	968	-	-	-	-	-	145	1,113	-	-	1,113	-	-	-	-	-	-	1,720	-
5b.1.3	Grade & landscape site	-	199	-	-	-	-	-	30	228	-	-	228	-	-	-	-	-	-	625	-
5b.1.4	Final report to NRC	-	-	-	-	-	-	210	32	242	242	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	15,735	-	-	-	-	210	2,392	18,337	242	-	18,095	-	-	-	-	-	-	174,200	1,560
	Period 5b Additional Costs																				
5b.2.1	Concrete Crushing	-	920	-	-	-	-	11	140	1,071	-	-	1,071	-	-	-	-	-	-	4,751	-
5b.2.2	Demolition of ISFSI	-	3,295	-	-	-	-	58	503	3,856	-	-	3,856	-	-	-	-	-	-	32,435	160
5b.2.3	Circ Water Cofferdam	-	233	-	-	-	-	-	35	268	-	-	268	-	-	-	-	-	-	1,936	-
5b.2.4	Service Water Cofferdam	-	319	-	-	-	-	-	-	319	-	-	319	-	-	-	-	-	-	2,714	-
5b.2.5	Construction Debris	-	-	-	-	-	-	341	51	392	-	-	392	-	-	-	-	-	-	-	-
5b.2	Subtotal Period 5b Additional Costs	-	4,767	-	-	-	-	410	729	5,906	-	-	5,906	-	-	-	-	-	-	41,836	160
	Period 5b Collateral Costs																				
5b.3.1	Small tool allowance	-	153	-	-	-	-	-	23	176	-	-	176	-	-	-	-	-	-	-	-
5b.3.2	Non-Labor Overhead	-	-	-	-	-	-	135	20	156	-	-	156	-	-	-	-	-	-	-	-
5b.3.3	Corporate A&G	-	-	-	-	-	-	539	81	620	-	-	620	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	153	-	-	-	-	674	124	951	-	-	951	-	-	-	-	-	-	-	-
	Period 5b Period-Dependent Costs																				
5b.4.2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	7,278	-	-	-	-	-	1,092	8,369	-	-	8,369	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	376	56	432	-	-	432	-	-	-	-	-	-	-	-
5b.4.5	Security Staff Cost	-	-	-	-	-	-	1,689	253	1,942	-	-	1,942	-	-	-	-	-	-	-	50,126
5b.4.6	DOC Staff Cost	-	-	-	-	-	-	13,174	1,976	15,150	-	-	15,150	-	-	-	-	-	-	-	142,023
5b.4.7	Utility Staff Cost	-	-	-	-	-	-	5,524	829	6,353	-	-	6,353	-	-	-	-	-	-	-	81,454
5b.4	Subtotal Period 5b Period-Dependent Costs	-	7,278	-	-	-	-	20,763	4,206	32,247	-	-	32,247	-	-	-	-	-	-	-	273,603
5b.0	TOTAL PERIOD 5b COST	-	27,932	-	-	-	-	22,057	7,451	57,440	242	-	57,199	-	-	-	-	-	-	216,035	275,323
PERIOD 5 TOTALS		-	27,932	-	-	-	-	22,057	7,451	57,440	242	-	57,199	-	-	-	-	-	-	216,035	275,323
TOTAL COST TO DECOMMISSION		**9,944**	**97,259**	**16,255**	**5,241**	**7,622**	**47,330**	**825,331**	**170,663**	**1,179,646**	**787,916**	**325,619**	**66,111**	**92,830**	**225,146**	**751**	**281**	**1,773**	**19,807,010**	**1,244,859**	**10,527,130**

Table E
Virgil C. Summer Nuclear Station
SAFSTOR-2 Decommissioning Cost Estimate
(thousands of 2016 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours

TOTAL COST TO DECOMMISSION WITH 16.91% CONTINGENCY:	$1,179,646	thousands of 2016 dollars
TOTAL NRC LICENSE TERMINATION COST IS 66.79% OR:	$787,916	thousands of 2016 dollars
SPENT FUEL MANAGEMENT COST IS 27.6% OR:	$325,619	thousands of 2016 dollars
NON-NUCLEAR DEMOLITION COST IS 5.6% OR:	$66,111	thousands of 2016 dollars
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	226,178	cubic feet
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	1,773	cubic feet
TOTAL SCRAP METAL REMOVED:	52,852	tons
TOTAL CRAFT LABOR REQUIREMENTS:	1,244,859	man-hours

End Notes:
n/a - indicates that this activity not charged as decommissioning expense.
a - indicates that this activity performed by decommissioning staff.
0 - indicates that this value is less than 0.5 but is non-zero.
a cell containing " - " indicates a zero value

APPENDIX F

DETAILED COST ANALYSIS

ISFSI

Table F
Virgil C. Summer Nuclear Station
ISFSI Decommissioning Cost Estimate
DECON and SAFSTOR-1 Decommissioning Alternatives
(thousands of 2016 dollars)

Activity Description	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor									
Planning (characterization, specs and procedures)	-	-	-	-	290	290	-	-	1,096
Decontamination (activated disposition)	132	95	147	2,096	29	2,499	30,414	2,135	-
License Termination (radiological surveys)	-	-	-	-	1,313	1,313	-	11,060	-
Subtotal	**132**	**95**	**147**	**2,096**	**1,632**	**4,102**	**30,414**	**13,195**	**1,096**
Supporting Costs									
NRC and NRC Contractor Fees and Costs	-	-	-	-	400	400	-	-	776
Insurance	-	-	-	-	117	117	-	-	-
Property taxes	-	-	-	-	-	-	-	-	-
Plant energy budget	-	-	-	-	46	46	-	-	-
Non-Labor Overhead	-	-	-	-	12	12	-	-	-
Corporate A&G	-	-	-	-	25	25	-	-	
Security Staff Cost	-	-	-	-	206	206	-	-	5,013
Oversight Staff Cost	-	-	-	-	235	235	-	-	3,803
Subtotal	-	-	-	-	1,042	1,042	-	-	9,592
Total (w/o contingency)	132	95	147	2,096	2,674	5,144	30,414	13,195	10,688
Total (w/25% contingency)	165	119	184	2,620	3,342	6,430			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

DSM Account Balances

October 1, 2016 - September 30, 2017

DSM Account	Account Description	Sept 2017 Balance
1823256	1823256 - Res Appliance Recycling	610,561.88
1823259	1823259 - Res Limited Income	920,437.35
1823260	1823260 - Dsm Admin	643,578.12
1823261	1823261 - Res Benchmarking	508,026.32
1823263	1823263 - Res Energy Check Up	653,061.11
1823264	1823264 - Res Estar Light And Appliance	680,570.07
1823265	1823265 - Res New Hvac And Duct Work	1,401,620.40
1823271	1823271 - C & I Energy Wise For Business	3,593,317.64
1823273	1823273 - Small Business Direct Install	2,337,867.80
1823280	1823280 - Res Dsm Accum Amort	(7,020,933.03)
1823281	1823281 - Com Ind Dsm Accum Amort	(5,687,651.98)
1823282	1823282 - Res Dsm Carrying Costs	1,022,276.40
1823283	1823283 - Com Ind Dsm Carrying Costs	866,695.93
		529,428.01

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2013-2-E

March 14, 2013

IN RE: Annual Review of Base Rates for Fuel Costs of South Carolina Electric & Gas Company	)))	**SETTLEMENT AGREEMENT**

This Settlement Agreement is made between the South Carolina Office of Regulatory Staff ("ORS"), South Carolina Energy Users Committee ("SCEUC"), and South Carolina Electric & Gas Company ("SCE&G" or the "Company") (collectively referred to as the "Parties" or sometimes individually as a "Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina (the "Commission") pursuant to the procedure established in S.C. Code Ann. §58-27-865 (Supp. 2012), and the Parties to this Settlement Agreement are parties of record in the above-captioned docket;

WHEREAS, the Parties have varying legal positions regarding the issues in this case;

WHEREAS, the Parties have engaged in discussions to determine if a settlement would be in their best interest;

WHEREAS, following these discussions the Parties have each determined that their interest and the public interest would be best served by settling matters in the above-captioned case under the terms and conditions set forth below:

1. ORS's review of SCE&G's operation of its generating facilities resulted in ORS concluding that SCE&G has made reasonable efforts to maximize unit availability and minimize fuel costs. Additionally, ORS has determined that SCE&G took appropriate corrective action with respect to outages that occurred during the review period.

2. The Parties agree to stipulate into the record before the Commission the direct testimony and exhibits of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

a. SCE&G witnesses:
   i. Andy T. Barbee
   ii. Joseph K. Todd
   iii. Michael D. Shinn
   iv. Rose M. Jackson
   v. Allen W. Rooks
b. ORS witnesses:
   i. Joseph W. Coates
   ii. Michael L. Seaman-Huynh

3. SCE&G's net cumulative (under)-recovered balance of total fuel and variable environmental costs for the periods ending December 31, 2012, and April 30, 2013, are ($84,155,155) and ($71,310,286), respectively. As of December 31, 2012, the net cumulative (under)-recovered balance of ($84,155,155) consists of cumulative (under)-recovered base fuel costs of ($82,500,782) and cumulative (under)-recovered environmental costs of ($1,654,373). As of April 2013, the projected net cumulative (under)-recovered balance of ($71,310,286) consists of cumulative (under)-recovered base fuel costs of ($71,234,193) and cumulative (under)-recovered environmental costs of ($76,093).

4. Commission Order No. 2012-951 (issued December 20, 2012) established a base fuel component of 3.278 cents per kilowatt-hour ("kWh") for the period January 1, 2013, through the last billing cycle of April 2014 based on the Company's forecast. In keeping with that Order, SCE&G agrees to carry forward an amount equal to the actual base fuel (under)-recovered balance as of April 30, 2013, which is projected to be ($71,234,193). Carrying costs will be permitted for any (under)-collected amounts of base fuel costs that exceed ($24,338,526) from January 2013 through April 2014 at the rate of the 3-year U.S. Government Treasury Note as reported by the Wall Street Journal plus an all-in spread of 65 basis points (0.65 percentage points).

5. The appropriate fuel factors for SCE&G to charge pursuant to this Settlement Agreement for the period beginning with the first billing cycle in May 2013 and extending through the last billing cycle for April 2014 are listed below and set forth in the tariff sheet entitled "Adjustment for Fuel and Variable Environmental Costs," which is attached hereto as Exhibit A.

Class	Base Fuel Cost Component (cents/kWh)	Environmental Fuel Cost Component (cents/kWh)	Total Fuel Costs Factor (cents/kWh)
Residential	3.278	0.079	3.357
Small General Service	3.278	0.066	3.344
Medium General Service	3.278	0.055	3.333
Large General Service	3.278	0.036	3.314
Lighting	3.278	--	3.278

6. The Parties agree the fuel factors set forth above are consistent with S.C. Code Ann. § 58-27-865 (Supp. 2012) and Order No. 2012-951. The Parties further agree that, except as provided in Paragraph 7 herein, any and all challenges to SCE&G's historical fuel costs recovery for the period ending December 31, 2012, are not subject to further review; however,

the projected fuel costs for the period beginning January 1, 2013, and thereafter shall be an open issue in future fuel costs proceedings held under the procedure and criteria established in S.C. Code Ann. § 58-27-865 (Supp. 2012).

7. With regards to plant outages not completed as of December 31, 2012 and outages where final reports of the Company, contractor, governmental entities or others are not available, the Parties agree that ORS retains the right to review the reasonableness of the plant outage(s) and associated costs in the review period during which the outage is completed or when the report(s) on such outage(s) become available.

8. SCE&G agrees to apply any money received from litigation, arbitration, or negotiated settlements with coal suppliers, where the dispute is for non-deliveries, defaults or other similar non-performance issues or for other matters related to or associated with S.C. Code § 58-27-865 (Supp. 2012), to reduce the fuel costs account(s). SCE&G also agrees to provide the Parties with reports showing SCE&G's efforts to seek compensation for non-deliveries, defaults or other similar non-performance upon request.

9. SCE&G agrees to provide to ORS and SCEUC the following:

   a. Copies of the monthly fuel recovery reports currently filed with the Commission and ORS; and,

   b. Quarterly forecasts beginning with the quarter ending June 30, 2013, of the expected fuel factors to be set at SCE&G's next annual fuel proceeding and SCE&G's historical over (under)-recovered balance to date. SCE&G agrees it will put forth reasonable efforts to forecast the expected fuel factors to be set at its next annual fuel proceeding; however, the Parties agree that these quarterly forecasts will not be admitted into evidence in any future SCE&G proceeding.

10. The Parties agree this Settlement Agreement is reasonable, in the public interest, and in accordance with law and regulatory policy. This Settlement Agreement in no way constitutes a waiver or acceptance of the position of any Party concerning the requirements of S.C. Code Ann. § 58-27-865 (Supp. 2012) in any future proceeding.

11. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code § 58-4-10(B) (Supp. 2012). S.C. Code § 58-4-10(B)(1) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) Economic development and job attraction and retention in South Carolina; and
> (3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

12. The Parties agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission as a fair, reasonable, and full resolution in the above-captioned proceeding. The Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Settlement Agreement and the terms and conditions contained herein.

13. This written Settlement Agreement contains the complete agreement of the Parties. There are no other terms and conditions to which the Parties have agreed. This Settlement Agreement integrates all discussions among the Parties into the terms of this written document. The Parties agree that this Settlement Agreement will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will this Settlement Agreement or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If

the Commission should decline to approve this Settlement Agreement in its entirety, then any Party desiring to do so may withdraw from this Settlement Agreement without penalty.

14. This Settlement Agreement shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Settlement Agreement by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

Jeffrey M. Nelson, Esquire
South Carolina Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
Phone: (803) 737-0823
Fax: (803) 737-0895
Email: jnelson@regstaff.sc.gov

WE AGREE:

Representing and binding South Carolina Energy Users Committee

____

Scott Elliott, Esquire
Elliott and Elliott, P.A.
1508 Lady Street
Columbia, SC 29201
Phone: (803) 771-0555
Fax: (803) 771-8010
Email: selliott@elliottlaw.us

WE AGREE:

Representing and binding South Carolina Electric & Gas Company

Matthew W. Gissendanner

K. Chad Burgess, Esquire
Matthew W. Gissendanner, Esquire
South Carolina Electric & Gas Company
Mail Code C222
220 Operation Way
Cayce, SC 29033
Phone: (803) 217-8141
(803) 217-5359
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Email: chad.burgess@scana.com
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SOUTH CAROLINA ELECTRIC & GAS COMPANY — ELECTRICITY

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS — **RETAIL RATES**

APPLICABILITY

This adjustment is applicable to and is part of the Utility's South Carolina retail electric rate schedules.

The fuel and variable environmental costs, to be recovered in an amount rounded to the nearest one-thousandth of a cent per kilowatt-hour, will be determined by the following formulas:

$$F_C = \frac{E_F}{S} + \frac{G_F}{S_1}$$

$$F_{EC} = \frac{E_{EC} + G_{EC}}{S_2}$$

$$\text{Total Fuel Rate} = F_C + F_{EC}$$

Where:

F_C = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one-thousandth of a cent.

E_F = Total projected system fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

PLUS

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel costs associated with energy purchased are identifiable and are identified in the billing statement. Also, the cost of "firm generation capacity purchases," which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. Costs of "firm generation capacity purchases" includes the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

PLUS

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing Utility's avoided variable costs for the generation of an equivalent quantity of electric power.

Energy receipts that do not involve money payments such as diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

MINUS

(D) The cost of fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G_F = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E_F and S.

S_1 = Projected jurisdictional kilowatt-hour sales, for the period covered by the fuel costs included in E_F.

F_{EC} = Customer class variable environmental costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

SOUTH CAROLINA ELECTRIC & GAS COMPANY **ELECTRICITY**

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS **RETAIL RATES**

E_{EC} = The projected variable environmental costs including: a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, plus b) the cost of emission allowances, as used, including allowances for SO2, NOx, mercury and particulates minus net proceeds of sales of emission allowances, and c) as approved by the Commission, all other variable environmental costs incurred in relation to the consumption of fuel and air emissions caused thereby, including but not limited to environmental reagents, other environmental allowances, and emission related taxes. Any environmental related costs recovered through intersystem sales would be subtracted from the totals produced by subparts a), b), and c).

These environmental costs will be allocated to retail customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{EC} = Cumulative difference between jurisdictional customer class environmental fuel revenues billed and jurisdictional customer class environmental costs at the end of the month preceding the projected period utilized in E_{EC} and S_2.

S_2 = The projected jurisdictional customer class kilowatt-hour sales.

The appropriate revenue-related tax factor is to be included in these calculations.

FUEL RATES BY CLASS

The total fuel costs in cents per kilowatt-hour by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2013 through April, 2014:

Customer Class	F_C Rate	+	F_{EC} Rate	=	Total Fuel Rate
Residential	**3.278**		**0.079**		**3.357**
Small General Service	**3.278**		**0.066**		**3.344**
Medium General Service	**3.278**		**0.055**		**3.333**
Large General Service	**3.278**		**0.036**		**3.314**
Lighting	**3.278**		**0.000**		**3.278**

Effective Upon Approval by the Public
Service Commission of South Carolina

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2014-2-E

March 27, 2014

IN RE:	Annual Review of Base Rates for Fuel Costs of South Carolina Electric & Gas Company	)))	**SETTLEMENT AGREEMENT**

This Settlement Agreement is made among the South Carolina Office of Regulatory Staff ("ORS"), South Carolina Energy Users Committee ("SCEUC"), and South Carolina Electric & Gas Company ("SCE&G" or the "Company") (collectively referred to as the "Parties" or sometimes individually as a "Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina ("Commission") pursuant to the procedure established in S.C. Code Ann. § 58-27-865 (Supp. 2013), and the Parties to this Settlement Agreement are parties of record in the above-captioned docket;

WHEREAS, the Parties have varying legal positions regarding the issues in this proceeding;

WHEREAS, the Parties have engaged in discussions to determine if a settlement would be in their best interest;

WHEREAS, following these discussions the Parties have each determined that their interests and the public interest would be best served by settling matters in the above-captioned case under the terms and conditions set forth below:

1. ORS's review of SCE&G's operation of its generating facilities resulted in ORS concluding that SCE&G has made reasonable efforts to maximize unit availability and minimize fuel costs. Additionally, ORS has determined that SCE&G took appropriate corrective action with respect to outages that occurred during the review period of January 1, 2013, through December 31, 2013. Further, ORS has concluded that, subject to the adjustments set forth in its pre-filed direct testimony, SCE&G's accounting practices are in compliance with S.C. Code Ann. § 58-27-865 (Supp. 2013).

2. The Parties agree to stipulate into the record before the Commission the direct testimony and exhibits of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

a. SCE&G witnesses:
   i. George A. Lippard, III
   ii. Joseph K. Todd
   iii. Michael D. Shinn
   iv. Rose M. Jackson
   v. Keith C. Coffer, Jr.
   vi. Allen W. Rooks

b. ORS witnesses:
   i. Ivana C. Gearheart
   ii. Michael L. Seaman-Huynh

3. SCE&G and SCEUC agree with the accounting adjustment proposed by ORS. Accordingly, SCE&G's net cumulative (under)-recovered balance of total fuel and variable environmental costs for the periods ending December 31, 2013, and projected through April 30, 2014, are ($60,509,405) and ($54,444,098), respectively. As of December 31, 2013, the net cumulative (under)-recovered balance of ($60,509,405) consists of cumulative (under)-recovered

base fuel costs of ($60,307,192) and cumulative (under)-recovered environmental costs of ($202,213). As of April 30, 2014, the projected net cumulative (under)-recovered balance of ($54,444,098) consists of cumulative (under)-recovered base fuel costs of ($54,247,591) and cumulative (under)-recovered environmental costs of ($196,507). The projected net cumulative (under)-recovered balance as of April 30, 2014, totaling ($54,444,098) reflects the application of an estimated $46 million of gains from the settlement of certain forward-starting interest rate swap contracts to reduce fuel costs.

4. The Parties agree that the appropriate fuel factors for SCE&G to charge pursuant to this Settlement Agreement for the period beginning with the first billing cycle for May 2014 and extending through the last billing cycle for April 2015 are listed below and set forth in the tariff sheet entitled "Adjustment for Fuel and Variable Environmental Costs," which is attached hereto as Exhibit A.

Class	Base Fuel Cost Component (cents/kWh)	Environmental Fuel Cost Component (cents/kWh)	Total Fuel Costs Factor (cents/kWh)
Residential	3.325	0.079	3.404
Small General Service	3.325	0.066	3.391
Medium General Service	3.325	0.055	3.380
Large General Service	3.325	0.036	3.361
Lighting	3.325	--	3.325

5. The Parties agree that the total fuel costs factors set forth in Paragraph 4 do not completely eliminate the (under)-collected balance of total fuel costs. Therefore, the Parties agree that SCE&G will be allowed to charge and accrue carrying costs monthly on its base fuel (under)-collected balance. The applicable period during which carrying costs may be applied pursuant to this Settlement Agreement begins May 1, 2014, and ends April 30, 2015. The applicable interest rate used to calculate the carrying costs under this Settlement Agreement is

the rate of interest as of the first day of each month during the applicable period for the 3-year U.S. Government Treasury Note, as reported by the *Wall Street Journal*, either in its print edition or on its website, plus an all-in spread of 65 basis points (0.65 percentage points).

6. In Docket No. 2014-88-E, SCE&G proposed decreasing its Rider Related to Pension Costs ("Pension Rider") from $0.00051 per kilowatt-hour ("kWh") to $0.00004 per kWh, resulting in a reduction in the Pension Rider of $0.00047. The Parties agree that the rate rider decrease proposed in Docket No. 2014-88-E offsets the adjustment to the base fuel factor set forth in Paragraph 4, resulting in no net increase to retail electric customers' bills.

7. The Parties agree the fuel factors set forth above are consistent with S.C. Code Ann. § 58-27-865 (Supp. 2013). The Parties further agree that, except as provided in Paragraph 8 herein, any and all challenges to SCE&G's historical fuel costs recovery for the period ending December 31, 2013, are not subject to further review; however, the projected fuel costs for the period beginning January 1, 2014, and thereafter shall be an open issue in future fuel costs proceedings held under the procedure and criteria established in S.C. Code Ann. § 58-27-865 (Supp. 2013).

8. With regards to plant outages not completed as of December 31, 2013, and outages where final reports of the Company, contractors, governmental entities or others are not available, the Parties agree that ORS retains the right to review the reasonableness of the plant outage(s) and associated costs in the review period during which the outage is completed or when the report(s) on such outage(s) become available.

9. SCE&G agrees to apply any money received from litigation, arbitration, or negotiated settlements with coal suppliers, where the dispute is for non-deliveries, defaults or other similar non-performance issues or for other matters related to or associated with S.C. Code

§ 58-27-865 (Supp. 2013), to reduce the fuel costs account(s). SCE&G also agrees to provide the Parties with reports showing SCE&G's efforts to seek compensation for non-deliveries, defaults or other similar non-performance upon request.

10. SCE&G agrees to provide to ORS and SCEUC the following:

a. Copies of the monthly fuel recovery reports currently filed with the Commission and ORS; and,

b. Quarterly forecasts beginning with the quarter ending June 30, 2014, of the expected fuel factors to be set at SCE&G's next annual fuel proceeding and SCE&G's historical over (under)-recovered balance to date. SCE&G agrees it will put forth reasonable efforts to forecast the expected fuel factors to be set at its next annual fuel proceeding; however, the Parties agree that these quarterly forecasts will not be admitted into evidence in any future SCE&G proceeding.

11. The Parties agree this Settlement Agreement is reasonable, in the public interest, and in accordance with law and regulatory policy. This Settlement Agreement in no way constitutes a waiver or acceptance of the position of any Party concerning the requirements of S.C. Code Ann. § 58-27-865 (Supp. 2013) in any future proceeding.

12. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code § 58-4-10(B) (Supp. 2013). S.C. Code § 58-4-10(B)(1) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) Economic development and job attraction and retention in South Carolina; and
> (3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of

> utility facilities so as to provide reliable and high quality utility services."

13. The Parties agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission as a fair, reasonable, and full resolution in the above-captioned proceeding. The Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Settlement Agreement and the terms and conditions contained herein.

14. This written Settlement Agreement contains the complete agreement of the Parties. There are no other terms and conditions to which the Parties have agreed. This Settlement Agreement integrates all discussions among the Parties into the terms of this written document. The Parties agree that this Settlement Agreement will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will this Settlement Agreement or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If the Commission should decline to approve this Settlement Agreement in its entirety, then any Party desiring to do so may withdraw from this Settlement Agreement without penalty.

15. This Settlement Agreement shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Settlement Agreement by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

Jeffrey M. Nelson, Esquire
South Carolina Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
Phone: (803) 737-0823
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WE AGREE:

Representing and binding South Carolina Energy Users Committee

Scott Elliott, Esquire
Elliott and Elliott, P.A.
1508 Lady Street
Columbia, SC 29201
Phone: (803) 771-0555
Fax: (803) 771-8010
Email: selliott@elliottlaw.us

WE AGREE:

Representing and binding South Carolina Electric & Gas Company

K. Chad Burgess, Esquire
Matthew W. Gissendanner, Esquire
South Carolina Electric & Gas Company
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Phone: (803) 217-8141
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SOUTH CAROLINA ELECTRIC & GAS COMPANY **ELECTRICITY**

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS **RETAIL RATES**
(Page 1 of 2)

APPLICABILITY

This adjustment is applicable to and is part of the Utility's South Carolina retail electric rate schedules.

The fuel and variable environmental costs, to be recovered in an amount rounded to the nearest one-thousandth of a cent per kilowatt-hour, will be determined by the following formulas:

$$F_C = \frac{E_F}{S} + \frac{G_F}{S_1}$$

$$F_{EC} = \frac{E_{EC} + G_{EC}}{S_2}$$

$$\text{Total Fuel Rate} = F_C + F_{EC}$$

Where:

F_C = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one-thousandth of a cent.

E_F = Total projected system fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

PLUS

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel costs associated with energy purchased are identifiable and are identified in the billing statement. Also, the cost of "firm generation capacity purchases," which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. Costs of "firm generation capacity purchases" includes the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

PLUS

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing Utility's avoided variable costs for the generation of an equivalent quantity of electric power.

Energy receipts that do not involve money payments such as diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

MINUS

(D) The cost of fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G_F = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E_F and S.

S_1 = Projected jurisdictional kilowatt-hour sales, for the period covered by the fuel costs included in E_F.

F_{EC} = Customer class variable environmental costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

SOUTH CAROLINA ELECTRIC & GAS COMPANY **ELECTRICITY**

ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS **RETAIL RATES**
(Page 2 of 2)

E_{EC} = The projected variable environmental costs including: a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, plus b) the cost of emission allowances, as used, including allowances for SO2, NOx, mercury and particulates minus net proceeds of sales of emission allowances, and c) as approved by the Commission, all other variable environmental costs incurred in relation to the consumption of fuel and air emissions caused thereby, including but not limited to environmental reagents, other environmental allowances, and emission related taxes. Any environmental related costs recovered through intersystem sales would be subtracted from the totals produced by subparts a), b), and c).

These environmental costs will be allocated to retail customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{EC} = Cumulative difference between jurisdictional customer class environmental fuel revenues billed and jurisdictional customer class environmental costs at the end of the month preceding the projected period utilized in E_{EC} and S_2.

S_2 = The projected jurisdictional customer class kilowatt-hour sales.

The appropriate revenue-related tax factor is to be included in these calculations.

FUEL RATES BY CLASS

The total fuel costs in cents per kilowatt-hour by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2014 through April, 2015:

Customer Class	F_C Rate	+	F_{EC} Rate	=	Total Fuel Rate
Residential	**3.325**		**0.079**		**3.404**
Small General Service	**3.325**		**0.066**		**3.391**
Medium General Service	**3.325**		**0.055**		**3.380**
Large General Service	**3.325**		**0.036**		**3.361**
Lighting	**3.325**		**0.000**		**3.325**

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2014-86-E

IN RE:

Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of Two 230 kV Transmission Lines from its Lyles Substation to its Lake Murray Substation	))))))))	**STIPULATION**

This Stipulation is made by and between the South Carolina Office of Regulatory Staff ("ORS") and South Carolina Electric & Gas Company ("SCE&G") (collectively referred to as the "Parties" or sometimes individually as a "Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina ("Commission") pursuant to the provisions in S.C. Code Ann. § 58-33-10 *et seq.* (1976 & Supp. 2013) ("the Siting Act") and 10 S.C. Ann. Regs. 103-304 (2012) at the request of SCE&G, which filed an Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of Two 230 kV Transmission Lines from its Lyles Substation to its Lake Murray Substation ("Application");

WHEREAS, in the Application, SCE&G seeks a Certificate of Environmental Compatibility and Public Convenience and Necessity ("Certificate") for the construction and operation of two 230 kV Transmission Lines from its Lyles 230/115 kV Substation in

Columbia, South Carolina, to its Lake Murray 230/115 kV Substation near the Saluda River Dam on the basis that, after the retirement of the McMeekin Generating Station, in the event of the loss of the existing Edenwood-Lake Murray 230 kV Line and one of the 230/115 kV autotransformers at the Lake Murray 230/115 kV Substation, the remaining Lake Murray 230/115 kV autotransformer would be overloaded;

WHEREAS, the Parties to this Stipulation are parties of record in the above-captioned docket;

WHEREAS, in accordance with the provisions of S.C. Code Ann. § 58-33-140 (1976 & Supp. 2013) the South Carolina Department of Health and Environmental Control, the Department of Natural Resources, and the Department of Parks, Recreation, and Tourism, are also parties to this proceeding (collectively, the "Other Parties of Record"). The Other Parties of Record have been contacted with regard to the Stipulation; however, they have not taken a position on this matter;

WHEREAS, the Parties have engaged in discussions to determine if a Stipulation would be in their best interest; and

WHEREAS, following these discussions the Parties have determined that their interests, and those of the public, would be best served by reaching an agreement on matters set forth in SCE&G's Application in the above-captioned case under the terms and conditions set forth below:

1. The Parties agree to stipulate into the record before the Commission the direct testimony of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

A. SCE&G witnesses: Hubert C. Young, III and Dwight M. Hollifield
B. ORS witness: Michael L. Seaman-Huynh.

2. As a compromise, the following is adopted, accepted, and acknowledged as the agreement of the Parties:

A. ORS will recommend that the Commission approve SCE&G's Application and grant SCE&G a Certificate for two 230 kV Transmission Lines, and associated facilities, between its Lyles Substation and its Lake Murray Substation, as requested in the Application in this Docket;

B. SCE&G agrees to follow all South Carolina, Commission and local government regulations and laws arising from matters set forth in the Application; and

C. SCE&G will notify ORS and the Commission when the facilities begin commercial operation and of any changes to the planned commercial operation dates.

3. The Parties agree this Stipulation is reasonable, in the public interest and in accordance with law and regulatory policy.

4. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code §58-4-10(B) (Supp. 2013). S.C. Code §58-4-10(B)(1) through (3) reads in part as follows:

"... public interest' means a balancing of the following:

(1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
(2) Economic development and job attraction and retention in South Carolina; and
(3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

5. The Parties agree to cooperate in good faith with one another in recommending to the Commission that this Stipulation be accepted and approved by the Commission as a fair, reasonable and full resolution in the above-captioned proceeding. The Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Stipulation and the terms and conditions contained herein.

6. This written Stipulation contains the complete agreement of the Parties. There are no other terms and conditions to which the Parties have agreed. The Parties agree that this Stipulation will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will the Stipulation or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If the Commission should decline to approve the Stipulation in its entirety, then any Party desiring to do so may withdraw from the Stipulation without penalty.

7. This Stipulation shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Stipulation by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Stipulation.

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

Jeffrey M. Nelson, Esquire
South Carolina Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, South Carolina 29201
Phone: 803.737.0823
Fax: 803.737.0895
Email: jnelson@regstaff.sc.gov

WE AGREE:

Representing and binding South Carolina Electric & Gas Company

Matthew W. Gissendanner

K. Chad Burgess, Esquire
Matthew W. Gissendanner, Esquire
South Carolina Electric & Gas Company
220 Operation Way MC C222
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matthew.gissendanner@scana.com

BEFORE

THE PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2014-86-E

IN RE:	Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of Two 230 kV Transmission Lines from Its Lyles Substation to Its Lake Murray Substation	))))))	**CERTIFICATE OF SERVICE**

This is to certify that I, Karen D. Elliott, have this date served one (1) copy of the **STIPULATION** in the above-referenced matter to the person(s) named below by causing said copy to be deposited in the United States Postal Service, first class postage prepaid and affixed thereto, and addressed as shown below:

Jacquelyn S. Dickman, Esquire
SCDHEC
2600 Bull Street
Columbia, SC, 29201

Alvin A. Taylor, Director
South Carolina Department of Natural Resources
Post Office Box 167
Columbia, SC, 29202

Duane Parrish, Director
South Carolina Department of Parks, Recreation and Tourism
1205 Pendleton Street, Suite 248
Columbia, SC, 29201

Matthew W. Gissendanner, Esquire
K. Chad Burgess, Esquire
South Carolina Electric & Gas Company/SCANA Corporation
220 Operation Way - MC C222
Cayce, SC, 29033-3701

Karen D. Elliott

Karen D. Elliott

May 13, 2014
Columbia, South Carolina

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2015-2-E

April 2, 2015

IN RE: Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	)))	**SETTLEMENT AGREEMENT**

This Settlement Agreement is made among the South Carolina Office of Regulatory Staff ("ORS"), South Carolina Energy Users Committee, and South Carolina Electric & Gas Company ("SCE&G") (collectively referred to as the "Settling Parties" or sometimes individually as a "Settling Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina ("Commission") pursuant to the procedure established in S.C. Code Ann. § 58-27-865 (Supp. 2014), and the Settling Parties to this Settlement Agreement are parties of record in the above-captioned docket;

WHEREAS, the Settling Parties have varying legal positions regarding the issues in this proceeding;

WHEREAS, the Settling Parties have engaged in discussions to determine if a settlement would be in their best interest;

WHEREAS, following these discussions the Settling Parties have each determined that their interests and the public interest would be best served by settling matters in the above-captioned case under the terms and conditions set forth below:

1. ORS's review of SCE&G's operation of its generating facilities resulted in ORS concluding that SCE&G has made reasonable efforts to maximize unit availability and minimize fuel costs. Additionally, ORS has determined that SCE&G took appropriate corrective action with respect to outages that occurred during the review period of January 1, 2014, through December 31, 2014. Further, ORS has concluded that, subject to the adjustments set forth in its pre-filed direct testimony, SCE&G's accounting practices are in compliance with S.C. Code Ann. § 58-27-865 (Supp. 2014).

2. The Settling Parties agree to stipulate into the record before the Commission the direct testimony and exhibits of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

a. SCE&G witnesses:
   i. George A. Lippard, III
   ii. Joseph K. Todd
   iii. Michael D. Shinn
   iv. J. Darrin Kahl
   v. Thomas N. Effinger
   vi. Allen W. Rooks
b. ORS witnesses:
   i. Robert A. Lawyer
   ii. Michael L. Seaman-Huynh

3. The Settling Parties agree to accept all recommendations in ORS's testimony and exhibits. Accordingly, SCE&G's net cumulative (under)-recovered balance of total base fuel, variable environmental, and avoided capacity costs for the periods ending December 31, 2014, and projected through April 30, 2015, are ($64,150,324) and ($36,081,435), respectively. As of December 31, 2014, the net cumulative (under)-recovered balance of ($64,150,324) consists of

cumulative (under)-recovered base fuel costs of ($64,427,701) and cumulative over-recovered environmental and avoided capacity costs of $277,377. As of April 30, 2015, the projected net cumulative (under)-recovered balance of ($36,081,435) consists of cumulative (under)-recovered base fuel costs of ($36,467,759) and cumulative over-recovered environmental and avoided capacity costs of $386,324.

4. The Settling Parties agree that the appropriate fuel factors for SCE&G to charge pursuant to this Settlement Agreement for the period beginning with the first billing cycle for May 2015 and extending through the last billing cycle for April 2016 are listed below and set forth in the tariff sheet entitled "Adjustment for Fuel, Variable Environmental, and Avoided Capacity Costs," which is attached hereto as Exhibit A.

Class	Base Fuel Cost Component (cents/kWh)	Environmental Fuel & Avoided Capacity Cost Component (cents/kWh)	Total Fuel Costs Factor (cents/kWh)
Residential	3.137	0.076	3.213
Small General Service	3.137	0.076	3.213
Medium General Service	3.137	0.066	3.203
Large General Service	3.137	0.037	3.174
Lighting	3.137	0.000	3.137

5. The Settling Parties agree that the total fuel costs factors set forth in Paragraph 4 above are projected to eliminate SCE&G's (under)-collected balance of total fuel costs as of April 30, 2016.

6. If approved by the Commission, the ORS proposed rates would decrease the average monthly bill for a residential customer on Rate 8 using 1,000 kWh by approximately $1.91, from $146.40 to $144.49.

7. The Settling Parties agree the fuel factors set forth above are consistent with S.C. Code Ann. § 58-27-865 (Supp. 2014). The Settling Parties further agree that, except as provided

in Paragraph 8 herein, any and all challenges to SCE&G's historical fuel costs recovery for the period ending December 31, 2014, are not subject to further review; however, the projected fuel costs for the period beginning January 1, 2015, and thereafter, shall be an open issue in future fuel costs proceedings held under the procedure and criteria established in S.C. Code Ann. § 58-27-865 (Supp. 2014).

8. With regards to plant outages not completed as of December 31, 2014, and outages where final reports of SCE&G, contractors, governmental entities or others are not available, the Settling Parties agree that ORS retains the right to review the reasonableness of the plant outage(s) and associated costs in the review period during which the outage is completed or when the report(s) on such outage(s) become available.

9. SCE&G agrees to apply any money received or saved from litigation, arbitration, termination of contract, or negotiated settlements with coal suppliers, where the dispute is for non-deliveries, defaults or other similar non-performance issues or for other matters related to or associated with S.C. Code § 58-27-865 (Supp. 2014), to reduce the fuel costs account(s).

10. SCE&G agrees to provide the following to the other Settling Parties:

a. Copies of the monthly fuel recovery reports currently filed with the Commission and ORS; and,

b. Quarterly forecasts beginning with the quarter ending June 30, 2015, of the expected fuel factors to be set at SCE&G's next annual fuel proceeding and SCE&G's historical over (under)-recovered balance to date. SCE&G agrees it will put forth reasonable efforts to forecast the expected fuel factors to be set at its next annual fuel proceeding; however, the Settling Parties agree that these quarterly forecasts will not be admitted into evidence in any future SCE&G proceeding.

11. The Settling Parties agree this Settlement Agreement is reasonable, in the public interest, and in accordance with law and regulatory policy. This Settlement Agreement in no way constitutes a waiver or acceptance of the position of any Settling Party concerning the requirements of S.C. Code Ann. § 58-27-865 (Supp. 2014) in any future proceeding.

12. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code § 58-4-10(B) (Supp. 2014). S.C. Code § 58-4-10(B)(1) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) Economic development and job attraction and retention in South Carolina; and
> (3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

13. The Settling Parties agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission as a fair, reasonable, and full resolution in the above-captioned proceeding. The Settling Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Settlement Agreement and the terms and conditions contained herein.

14. This written Settlement Agreement contains the complete agreement of the Settling Parties. There are no other terms and conditions to which the Settling Parties have agreed. This Settlement Agreement integrates all discussions among the Settling Parties into the terms of this written document. The Settling Parties agree that this Settlement Agreement will

not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will this Settlement Agreement or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If the Commission should decline to approve this Settlement Agreement in its entirety, then any Settling Party desiring to do so may withdraw from this Settlement Agreement without penalty.

15. This Settlement Agreement shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Settling Parties hereto. Therefore, each Settling Party acknowledges its consent and agreement to this Settlement Agreement by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Settling Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

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Andrew M. Bateman, Esquire
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WE AGREE:

Representing and binding South Carolina Energy Users Committee

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WE AGREE:

Representing and binding South Carolina Electric & Gas Company

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ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL, AND AVOIDED CAPACITY COSTS **RETAIL RATES**

APPLICABILITY

This adjustment is applicable to and is part of the Utility's South Carolina retail electric rate schedules.

The fuel, variable environmental, and avoided capacity costs, to be recovered in an amount rounded to the nearest one-thousandth of a cent per kilowatt-hour, will be determined by the following formulas:

$$F_C = \frac{E_F}{S} + \frac{G_F}{S_1}$$

$$F_{EC} = \frac{E_{EC} + G_{EC}}{S_2}$$

$$\text{Total Fuel Rate} = F_C + F_{EC}$$

Where:

F_C = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one-thousandth of a cent.

E_F = Total projected system fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

PLUS

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel costs associated with energy purchased are identifiable and are identified in the billing statement, and also including avoided energy costs incurred by the Utility. Also, the cost of "firm generation capacity purchases," which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. Costs of "firm generation capacity purchases" includes the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

PLUS

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing Utility's avoided variable costs for the generation of an equivalent quantity of electric power.

Energy receipts that do not involve money payments such as diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

MINUS

(D) The cost of fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G_F = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E_F and S.

S_1 = Projected jurisdictional kilowatt-hour sales, for the period covered by the fuel costs included in E_F.

F_{EC} = Customer class variable environmental and avoided capacity costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

EXHIBIT A

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL, AND AVOIDED CAPACITY COSTS **RETAIL RATES**

E_{EC} = The projected variable environmental costs including: a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, plus b) the cost of emission allowances, as used, including allowances for SO2, NOx, mercury and particulates minus net proceeds of sales of emission allowances, and c) as approved by the Commission, all other variable environmental costs incurred in relation to the consumption of fuel and air emissions caused thereby, including but not limited to environmental reagents, other environmental allowances, and emission related taxes. Any environmental related costs recovered through intersystem sales would be subtracted from the totals produced by subparts a), b), and c). This component also includes avoided capacity costs incurred by the Utility.

These environmental and avoided capacity costs will be allocated to retail customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{EC} = Cumulative difference between jurisdictional customer class environmental fuel revenues billed and jurisdictional customer class environmental costs at the end of the month preceding the projected period utilized in E_{EC} and S_2.

S_2 = The projected jurisdictional customer class kilowatt-hour sales.

The appropriate revenue-related tax factor is to be included in these calculations.

FUEL RATES BY CLASS

The total fuel costs in cents per kilowatt-hour by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2015 through April, 2016:

Customer Class	F_C Rate	+	F_{EC} Rate	=	Total Fuel Rate
Residential	**3.137**		**0.076**		**3.213**
Small General Service	**3.137**		**0.076**		**3.213**
Medium General Service	**3.137**		**0.066**		**3.203**
Large General Service	**3.137**		**0.037**		**3.174**
Lighting	**3.137**		**0.000**		**3.137**

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December 11, 2014

VIA ELECTRONIC FILING

Jocelyn Boyd, Esquire
Chief Clerk/Administrator
Public Service Commission of South Carolina
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Columbia, SC 29210

Re: Petition of the Office of Regulatory Staff to Establish Generic Proceeding Pursuant to the Distributed Energy Resource Program Act, No. 236 of 2014, Ratification No. 241, Senate Bill No. 1189
Docket No. 2014-246-E

Dear Ms. Boyd:

Please find enclosed a Settlement Agreement in the above-referenced matter. Should you have any questions or concerns, please do not hesitate to contact me.

Sincerely,

Shannon B. Hudson

Shannon B. Hudson

Enclosure

cc: All Parties of Record

I. Parties to this Settlement Agreement

The parties to this Settlement Agreement (individually, the "Party" or collectively, the "Parties") are listed on the signature pages that follow. The following Parties may be referenced hereafter as follows: South Carolina Office of Regulatory Staff ("ORS"); Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., South Carolina Electric & Gas Company (individually, the "Utility" and collectively, the "Utilities"); Central Electric Power Cooperative, Inc. and The Electric Cooperatives of South Carolina, Inc. (collectively, the "Coops"); South Carolina Coastal Conservation League, the Southern Alliance for Clean Energy, the South Carolina Solar Business Alliance, LLC, Sustainable Energy Solutions, LLC, Solbridge Energy, LLC, The Alliance for Solar Choice, and the Sierra Club (collectively, the "Solar Parties").

II. Introduction and Preamble

1. The Parties believe that this Settlement Agreement is consistent with both the spirit and the letter of Act 236 ("the Act").

2. The Parties acknowledge and agree that this Settlement Agreement is a product of negotiations and includes compromises made in order to reach a comprehensive settlement that all Parties can support. The Parties accept this Settlement Agreement as a whole and agree not to challenge any term or part for the duration of this Settlement Agreement, which expires January 1, 2021. However, Parties are not precluded from participating in future proceedings to set and adopt policies which will be implemented after the expiration of this Settlement Agreement. If any term or part of this Settlement Agreement is not adopted, a Party reserves the right to withdraw from the Settlement Agreement pursuant to the steps in Section IV.2.

3. The Solar Parties take the position (a) that due to environmental and other factors, if all inputs are fully quantified, the true value of solar would be such that each kilowatt hour ("kWh") of energy generated by a solar customer-generator, and intended primarily to offset part or all of the customer-generator's own electrical use, would be at least as valuable, for ratemaking purposes, as a kWh of power supplied to that customer from the Utility grid ("1:1 Rate"), and (b) that no charges specific to solar customer-generators should be levied.

4. The Solar Parties, however, acknowledge that quantifying the value of certain benefits of solar power would be difficult and contentious at this time. In the interest of settlement, the Solar Parties are willing to agree to forego quantifying the value of certain benefits of solar power so long as the 1:1 Rate can be achieved.

5. The ORS, Utilities, and Coops take the position (a) that S.C. Code §§ 58-40-10, et seq., ("the Net Metering Statute") requires net metering rates to be set based on the net cost to serve customer-generators; (b) that it would constitute a subsidy to Distributed Energy Resource ("DER") customers to value DER generation at a level higher than is indicated by the benefits quantifiable under the known and measurable standard for ascertaining costs in a ratemaking context, and (c) that by law any subsidy for DER generation should be captured in the Utility's DER Program ("DER Program") as a DER expense to be measured and recovered subject to the cost caps and other limitations that apply under S.C. Code § 58-39-110.

6. The ORS, Utilities, and Coops, however, acknowledge that those provisions of the Act were intended and designed to incent the development of DER such as solar customer-generation, in South Carolina. In the interest of settlement, the Utilities are willing to agree to incent net metered DER

generation to achieve the 1:1 Rate during the term of this Settlement Agreement and to recover such incentive costs from customers as a component of the Utilities' respective DER Programs, subject to the limitations of South Carolina law.

7. As a practical means to bridge the differences between the Parties in their positions in this proceeding and without any Party waiving or abandoning its positions related to the proper interpretation or application of the Net Metering Statute or any other matter set forth in this proceeding, the Parties have agreed to resolve the matters at issue in this proceeding by agreeing as follows:

a. The 1:1 Rate shall be preserved for the term of this Settlement Agreement as set forth below;
b. The ORS Methodology, as defined below, shall be used to compute the value of DER generation;
c. The difference between the value of DER generation, as computed using the ORS Methodology, and the 1:1 Rate shall be treated as a DER program expense and collected accordingly through the fuel clause. This difference shall not be recovered through base rates;
d. The other terms of this Settlement Agreement, as set forth below, detail how this arrangement will be carried out.

III. Elements of Settlement Proposal

1. Within 60 days of the effective date of this Settlement Agreement, the Utilities will each file with the Public Service Commission of South Carolina ("Commission") applications for the approval of the initial DER Program consistent with the terms of this Settlement Agreement and the terms and conditions of the Act. Utility DER Programs will include provisions for incentives to residential and small commercial customers and will make new tariffs, amendments to existing tariffs, and/or programs available to customer-generators with production of less than 20 kilowatt ("kW") ("Residential/Small Commercial"). DER Programs will include the following provisions:

a. The Utilities shall propose to make available DER incentives available to Residential/Small Commercial customer-generators with production of less than 20 kW ("Residential/Small Commercial DER Incentives") that provide these customer-generators with an investment incentive (i.e., an up-front incentive or rebate) and/or a fixed, production-based incentive payment. These incentives shall provide price-certainty to the customer-generator over a defined term.
b. In aggregate and over the DER planning horizon, the proposed Residential/Small Commercial DER Incentives shall be reasonably sufficient to enable the Utilities to meet the Residential/Small Commercial customer-generator adoption targets enumerated in S.C. Code § 58-39-130 (C)(2).
c. The Utilities shall propose to make Residential/Small Commercial DER Incentives available to all qualifying customer-generators on a non-discriminatory basis subject to the terms and provisions of general law, including the Act, and any limitations contained therein, up to a cumulative capacity no less than 0.25% of the Utility's previous five-year average South Carolina retail peak demand, as defined by the Act.

d. The Utilities shall propose to make Residential/Small Commercial DER Incentives available retroactively to customer-generators who interconnect between January 1, 2015, and the date on which the Commission approves each Utility's DER application.
e. To be eligible for the Residential/Small Commercial DER Incentive, the customer-generator must agree to the installation of metering equipment, as specified by the Utility, sufficient to read the production of the facility.
f. The Utilities shall include in their DER applications a provision that allows customer-generators the option, at the expiration of the term of a particular DER Incentive, to request and receive service under any available schedule or tariff for which they qualify.
g. Nothing herein is intended to obviate the Utilities' statutory obligation as enumerated in S.C. Code § 58-39-130 (C)(2)(b) to provide incentives to customers to purchase or lease renewable energy facilities up to 1,000 kW.
h. The rate and tariff structure under which Residential/Small Commercial DER Incentives are to be provided shall be determined in the proceedings to consider the DER Program filings of the Utilities.

2. Within 60 days of the adoption by the Commission of a final, unappealable order that approves and adopts the terms of this Settlement Agreement as the generic net metering methodology required by S.C. Code § 58-40-20(F)(4) of the Act, the Utilities will each file with the Commission separate applications for approval of the following:

a. **Net Metering Tariffs:** New net metering tariffs (the "Net Metering Tariffs") shall incorporate the terms of this Settlement Agreement as well as the terms defined in S.C. Code § 58-40-10, including allowable customer-generator system size up to 1,000 kW, net metering capacity cap, annual kWh credit reconciliation, and other terms and conditions required by the Act for net metering tariffs adopted under its provisions. Settlement Agreement Attachment B is illustrative of the Net Metering Tariffs and the required tariff components.
b. **Net Metering Incentives:** A Net Metering Incentive, funded through a DER Program ("DER NEM Incentive"), shall be applied to qualifying net metering customers sufficient to make such customer-generators' bills equal to the bills they would have received if the power generated by their DER facilities were valued at the 1:1 Rate.
    i. The DER NEM Incentive will be applied to customer-generators receiving service under the Net Metering Tariffs prior to January 1, 2021. DER NEM Incentives shall be available to these customers through December 31, 2025, or until these customers elect to receive service under a different tariff, whichever occurs first.
    ii. Net Metering Tariffs shall reference any Commission order(s) approving the terms of this Settlement Agreement which addresses the calculation of DER NEM Incentives. DER NEM Incentives will not be separately stated on each net metering customer's bill. All DER NEM Incentives shall be treated as Incremental Costs as defined in S.C. Code § 58-39-140.
    iii. Any DER Program must conform to the terms of this Settlement Agreement to trigger the requirement under this Settlement Agreement that the Utilities implement its Net Metering Tariff and DER Program. The Utilities shall propose

and seek in good faith to adopt DER Programs that provide DER NEM Incentives for net metering customers representing up to 2% of the Utility's five-year average South Carolina retail peak demand, which is the statutory cap on net metering customers under the Act, or until the expiration of this Settlement Agreement, whichever occurs first.

3. The net metering and DER program applications will be considered in separate, Utility-specific dockets before the Commission. All issues related to net metering rates and DER programs not addressed in this Settlement Agreement will be addressed in these Utility-specific proceedings, as appropriate. All interested parties shall have the right to fully participate in these proceedings. Utility cost recovery from customers related to net metering and DER programs shall be reviewed and determined in each Utility's fuel cost proceeding.
4. All Parties will support the terms of this Settlement Agreement and will support the adoption by the Utilities and Commission of programs, tariffs, orders and other rulings consistent with the terms of this Settlement Agreement and the Act. The Parties will take no action or advocate any position inconsistent with this commitment.
5. If the Utilities fail to comply with their obligations under Section III.2 above, the other Parties to this Settlement Agreement may seek a rule to show cause or other order of the Commission compelling the Utilities to take the action required or ordering other relief necessary or appropriate in the circumstances.
6. If any of the Parties to this Settlement Agreement other than a Utility fail to comply with their obligations under Section III.4 above, then the Utility shall notice the Parties of their intent to treat this Settlement Agreement as null and void and forego, withdraw, terminate or seek to cancel any applications, programs, tariffs, filings, orders or other proceedings undertaken in reliance on this Settlement Agreement. Within five (5) days of receiving notice of the Utility's intent, the Parties may petition the Commission for relief.
7. This Settlement Agreement shall expire on January 1, 2021 (the "Settlement Expiration Date"). Subject to the regulatory authority of the Commission and ORS, the Utilities will adopt Net Metering Tariffs that are consistent with the terms of this Settlement Agreement and will make them available to customers on a first-come, first-served basis until the Settlement Expiration Date, and subject to the caps on DER program expenses contained in S.C. Code § 58-39-150 of the Act.
8. The Parties have convened and developed, according to a process managed by ORS and its consultant Energy + Environmental Economics ("E3"), a specific, standardized methodology for assessing costs and benefits of the net metering program. The standardized methodology is reflected in Settlement Agreement Attachment A (the "Methodology"). The Methodology includes all categories of potential costs or benefits to the Utility system that are capable of quantification or possible quantification in the future. Where there is currently a lack of capability to accurately quantify a particular category and/or a lack of cost or benefit to the Utility system, that category has been included in the Methodology as a placeholder. (For example, Avoided CO_2 Emission Cost is included as a placeholder. A zero monetary value will be used until state or federal laws or regulations result in an avoidable cost on Utility systems for these emissions.) Placeholder categories will be updated and included in the calculation of costs and benefits of net metering if and when capabilities to reasonably

quantify those values and quantifiable costs or benefits to the Utility system in such categories become available.

9. As set forth below, the Utilities shall use the following methodology to compute the net estimated under-recovered (lost revenue) or over-recovered revenue (net benefit) from net metering customers under existing rate structures, based on the Utility's cost of service study within its last general rate case. The formula used to apply the Methodology shall be as follows:
   a. To determine the under-recovered or over-recovered revenue from the net metering customer:
      i. Compute what the actual or a representative customer's bill would have been under the applicable standard rate, without consideration of the production of the DER.
      ii. Subtract from that amount the actual or a representative customer's estimated bill under the applicable standard rates with consideration of the production of the DER.
      iii. Subtract from that amount the net benefits delivered by the DER as computed according to the Methodology and based upon the production of the DER.
      iv. If the final number is positive, the result is the "under-recovered revenue from the net metering customer."
      v. If the final number is negative, the result is the "over-recovered revenue from the net metering customer."
   b. For under-recovered revenue, calculate the amount of any DER NEM Incentive to be applied to allow a net metering customer to achieve the 1:1 Rate for gross production from the net metering facility.
   c. For over-recovered revenue, calculate the credit, if any, to be applied to a net metering customer.
      i. No DER NEM Incentive shall be provided when the net metering customer receives a credit.

10. The Utilities shall use actual customer-generator energy production data to the maximum extent available to calculate the costs and benefits of net metering on their system using the Methodology. In the absence of actual customer metered production data from a customer-generator's DER, the Utilities shall be allowed to estimate DER energy production for purposes of implementing the Methodology, consistent with best practices relating to such estimation and modeling.

11. The costs and benefits of net metering and the required amount of the DER NEM Incentive shall be computed and updated annually coincident in time with the Utility's filing under the fuel clause.

12. Each Utility shall file reports with the Commission and copy ORS when the following participation levels are reached to identify and illustrate the costs unrecovered, if any, arising from customer adoption of net metered DER generation through December 31, 2020: (1) 0.5%; (2) 1.0%; (3) 1.5%; and (4) 2.0% of the Utility's previous five-year average South Carolina retail peak demand, as defined by the Act.

13. The Parties acknowledge that the establishment of appropriate net metering rates is complicated by current Utility ratemaking methodologies which collect a substantial part of a

Utility's fixed cost of providing service to customers through volumetric or kWh charges. The Utilities and any interested parties may participate in the study of these issues to be conducted by ORS as required by S.C. Code § 58-27-1050.

14. Each Utility shall monitor and track ongoing unrecovered DER costs or unpaid benefits associated with the net metering program after the Settlement Agreement Expiration Date. The Utilities shall not propose any new separately enumerated charges or fees to be imposed specifically on customer-generators before the Settlement Agreement Expiration Date, and no standby service charges shall be imposed on customer-generators pursuant to the Utilities' Net Metering Tariffs before the Settlement Agreement Expiration Date. A Utility is not precluded, however, from seeking a change in general rates that apply in an identical manner to customer-generators and non-participating customers prior to reaching the 2% participation cap or the Settlement Expiration Date. If a general rate change is sought prior to the Settlement Expiration Date, the general rate change shall not include DER Program costs.

15. A customer-generator taking service under any net metering rates resulting from this Settlement Agreement shall have the right to remain on that rate, according to the terms and conditions specified in this Settlement Agreement through December 31, 2025, including protection against any new separately enumerated charges or fees that would only apply to DER customer-generators. The right to remain on a Net Metering Tariff shall be assignable by the customer-generator to subsequent owners of the premises to which the electrical generating system is connected and providing electrical service. The Utilities agree to file applications in a specific docket with the Commission for new net metering tariffs to replace the Net Metering Tariffs based on this Settlement Agreement no later than January 31, 2020; all interested parties shall have the right to fully participate in these proceedings.

IV. Miscellaneous

1. The Parties acknowledge that ORS has an on-going statutory mandate from the General Assembly of the State of South Carolina to protect the interest of the public in all matters related to the electric utility rates and terms and conditions of service. Nothing in this Settlement Agreement shall be construed to limit ORS in its fulfillment of this mandate.
2. This written Settlement Agreement contains the complete agreement of the Parties. The Parties agree that signing this Settlement Agreement does not constrain, inhibit or impair their arguments or positions in future proceedings. If the Commission declines to approve the agreement in its entirety, then any Party desiring to do so may withdraw from the agreement without penalty, within three (3) days of receiving notice of the decision, by providing written notice of withdrawal via electronic mail to all parties in that time period.
3. The Parties agree that the terms of this Settlement Agreement shall have no precedential value and shall not be cited in legal or regulatory proceedings except to enforce the terms of this Settlement Agreement.
4. This Settlement Agreement does not limit the rights of the signatories with respect to their ability to participate in a proceeding wherein the Utilities propose to populate the Methodology with Utility-specific data and information, or their ability to participate in

Commission review of Utility DER program offerings and proposals except as specified herein.

5. This Settlement Agreement is binding on the Parties only. It creates no rights in third parties nor are there third party beneficiaries to it. Only Parties who are signatories may make any claim under this Settlement Agreement.

6. The Parties agree to stipulate into the record before the Commission this Settlement Agreement. The Parties agree to stipulate into the record before the Commission the pre-filed testimony and exhibits of each Parties' witness(es) without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction. The Parties, however, reserve the right to engage in redirect examination of witnesses as necessary to respond to issues raised during the examination of their respective witnesses, if any, by the Commission or any non-settling party or by subsequently filed testimony.

7. The Parties agree this Settlement Agreement is reasonable, in the public interest, and in accordance with law and regulatory policy.

8. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code § 58-4-10(B) (Supp. 2013). S.C. Code § 58-4-10(B)(l) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) Economic development and job attraction and retention in South Carolina; and
> (3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

9. This Settlement Agreement shall be effective upon execution of the Parties and shall be interpreted according to South Carolina law.

10. This Settlement Agreement shall bind and inure to the benefit of each of the signatories hereto and their representatives, predecessors, successors, assigns, agents, shareholders, officers, directors (in their individual and representative capacities), subsidiaries, affiliates, parent corporations, if any, joint ventures, heirs, executors, administrators, trustees, and attorneys.

11. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Settlement Agreement by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the Settlement Agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind each Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

In witness whereof see our signatures below:

[SIGNATURE PAGES TO FOLLOW]

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

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WE AGREE:

Representing and binding The Sierra Club

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WE AGREE:

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WE AGREE:

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WE AGREE:

Representing and binding Central Electric Power Cooperative, Inc.

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I AGREE:

Representing and binding Frank Knapp, Jr., ***pro se***

Frank Knapp, Jr.
Frank Knapp, Jr.
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WE AGREE:

Representing and binding Wal-Mart Stores East, LP and Sam's East, Incorporated

<u>**NOT A PARTY TO THE SETTLEMENT**</u>
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WE AGREE:

Representing and binding South Carolina Energy Users Committee

NOT A PARTY TO THE SETTLEMENT

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Net Energy Metering ("NEM") Methodology

+/- Avoided Energy
+/- Energy Losses/Line Losses
+/- Avoided Capacity
+/- Ancillary Services
+/- Transmission and Distribution ("T&D") Capacity
+/- Avoided Criteria Pollutants
+/- Avoided CO_2 Emission Cost
+/- Fuel Hedge
+/- Utility Integration & Interconnection Costs
+/- Utility Administration Costs
+/- Environmental Costs
= **Total Value of NEM Distributed Energy Resource**

The following table details the components of the Methodology.

Methodology Component	Description	Calculation Methodology/Value
+/- Avoided Energy	Increase/reduction in variable costs to the Utility from conventional energy sources, i.e. fuel use and power plant operations, associated with the adoption of NEM.	Component is the marginal value of energy derived from production simulation runs per the Utility's most recent Integrated Resource Planning ("IRP") study and/or Public Utility Regulatory Policy Act ("PURPA") Avoided Cost formulation.
+/- Energy Losses/Line Losses	Increase/reduction of electricity losses by the Utility from the points of generation to the points of delivery associated with the adoption of NEM.	Component is the generation, transmission, and distribution loss factors from either the Utility's most recent cost of service study or its approved Tariffs. Average loss factors are more readily available, but marginal loss data is more appropriate and should be used when available.
+/- Avoided Capacity	Increase/reduction in the fixed costs to the Utility of building and maintaining new conventional generation resources associated with the adoption of NEM.	Component is the forecast of marginal capacity costs derived from the Utility's most recent IRP and/or PURPA Avoided Cost formulation. These capacity costs should be adjusted for the appropriate energy losses.
+/- Ancillary Services	Increase/reduction of the costs of services for the Utility such as operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of NEM.	Component includes the increase/decrease in the cost of each Utility's providing or procurement of services, whether services are based on variable load requirements and/or based on a fixed/static requirement, i.e. determined by an N-1 contingency. It also includes the cost of future NEM technologies like "smart inverters" if such technologies can provide services like VAR support, etc.

Methodology Component	Description	Calculation Methodology/Value
+/- T&D Capacity	Increase/reduction of costs to the Utility associated with expanding, replacing and/or upgrading transmission and/or distribution capacity associated with the adoption of NEM.	Marginal T&D distribution costs will need to be determined to expand, replace, and/or upgrade capacity on each Utility's system. Due to the nature of NEM generation, this analysis will be highly locational as some distribution feeders may or may not be aligned with the NEM generation profile although they may be more aligned with the transmission system profile/peak. These capacity costs should be adjusted for the appropriate energy losses.
+/- Avoided Criteria Pollutants	Increase/reduction of SOx, NOx, and PM10 emission costs to the Utility due to increase/reduction in production from the Utility's marginal generating resources associated with the adoption of NEM generation if not already included in the Avoided Energy component.	The costs of these criteria pollutants are most likely already accounted for in the Avoided Energy Component, but, if not, they should be accounted for separately. The Avoided Energy component must specify if these are included.
+/- Avoided CO_2 Emissions Cost	Increase/reduction of CO_2 emissions due to increase/reduction in production from each Utility's marginal generating resources associated with the adoption of NEM generation.	The cost of CO_2 emissions may be included in the Avoided Energy Component, but, if not, they should be accounted for separately. A zero monetary value will be used until state or federal laws or regulations result in an avoidable cost on Utility systems for these emissions.
+/- Fuel Hedge	Increase/reduction in administrative costs to the Utility of locking in future price of fuel associated with the adoption of NEM.	Component includes the increases/decreases in administrative costs of any Utility's current fuel hedging program as a result of NEM adoption and the cost or benefit associated with serving a portion of its load with a resource that has less volatility due to fuel costs than certain fossil fuels. This value does not include commodity gains or losses and may currently be zero.
+/- Utility Integration & Interconnection Costs	Increase/reduction of costs borne by each Utility to interconnect and integrate NEM.	Costs can be determined most easily by detailed studies and/or literature reviews that have examined the costs of integration and interconnection associated with the adoption of NEM. Appropriate levels of photovoltaic penetration increases in South Carolina should be included.
+/- Utility Administration Costs	Increase/reduction of costs borne by each Utility to administer NEM.	Component includes the incremental costs associated with net metering, such as hand billing of net metering customers and other administrative costs.
+/- Environmental Costs	Increase/reduction of environmental compliance and/or system costs to the Utility.	The environmental compliance and/or Utility system costs might be accounted for in the Avoided Energy component, but, if not, should be accounted for separately. The Avoided Energy component must specify if these are included. These environmental compliance and/ or Utility system costs must be quantifiable and not based on estimates.

Example of Net Energy Metering Generic Tariff Components

The standard Net Energy Metering ("NEM") tariff will contain the following components:

1. Availability provisions;
2. General eligibility and technical service-related provisions;
3. Monthly rate provisions relating to administrative charges and/or excess energy credit calculations;
4. Terms;

Customers electing service under (Tariff Name) or after (Effective Date of New Tariff) are eligible to remain on (Tariff Name) until December 31, 2025, or until such time the customer elects to terminate service under (Tariff Name), whichever occurs first. The rates set forth here are subject to Commission Order No. ___, in Docket No. 2014-246-E entered under the terms of S.C. Code § 58-40-20(F)(4). Eligibility for this rate will terminate as set forth in that Order. The value of distributed energy resource generation shall be computed using the methodology contained in Commission Order No. ____, in Docket No. 2014-246-E and updated annually. The value for (Year) is $____ per kilowatt hour ("kWh").

If a customer-generator's energy consumption exceeds the electricity provided by the customer-generator during a monthly billing period, the customer-generator shall be billed in kWh for the net electricity supplied by the Utility.

If a customer-generator's energy generation exceeds the electricity provided by the Utility during a monthly billing period, the customer-generator shall be credited for the excess kWh generated during that billing period.

Excess energy not used in the current billing month to reduce billed kWh usage shall be accumulated and used to reduce usage in future months. Any accumulated excess energy not used to reduce billed kWh usage shall be paid to the customer-generator each (Date of Zeroing Out) at the Utility's avoided cost for qualified facilities, zeroing-out the customer-generator's account of net excess kWh credits.

Service on (Tariff Name) will be closed to new participants as of January 1, 2021, or after statutory caps described in S.C. Code § 58-39-130 have been reached, whichever occurs first.

Customers who elect NEM service after January 1, 2021, will receive service in accordance with the NEM tariff in effect the time at which the customer requests NEM service.

5. Language specifying that the customer is responsible for the applicable customer charge/basic facilities charge and any applicable demand charges or extra facilities charges associated with standard rate (non-NEM), etc.;

6. Metering requirement provisions;

7. Safety, interconnection and inspection requirements;

8. Power factor provisions;

9. Contract period provisions;

10. Any other standard tariff language, as required.

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2015-103-E

June 29, 2015

IN RE: Petition of South Carolina Electric & Gas Company for Updates and Revisions to Schedules Related to the Construction of a Nuclear Base Load Generation Facility at Jenkinsville, South Carolina	)))))))	**SETTLEMENT AGREEMENT**

This Settlement Agreement ("Settlement Agreement") is made by and among the South Carolina Office of Regulatory Staff ("ORS"); South Carolina Energy Users Committee ("SCEUC"); and South Carolina Electric & Gas Company ("SCE&G" or the "Company") (collectively referred to as the "Parties" or sometimes individually as a "Party").

WHEREAS, on March 12, 2015, SCE&G filed a petition with the Public Service Commission of South Carolina ("Commission") requesting an order from the Commission approving an updated capital cost schedule and updated construction schedule for the construction of two 1,117 net megawatt nuclear units (the "Units") to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina (the "Petition");

WHEREAS, SCE&G filed its Petition pursuant to S.C. Code Ann. § 58-33-270(E) (Supp. 2014) of the Base Load Review Act ("BLRA"), which states:

> (E) As circumstances warrant, the utility may petition the commission, with notice to the Office of Regulatory Staff, for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order issued under this section. The commission

shall grant the relief requested if, after a hearing, the commission finds:

(1) as to the changes in the schedules, estimates, findings, or conditions, that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility; and

(2) as to the changes in the class allocation factors or rate designs, that the evidence of record indicates the proposed class allocation factors or rate designs are just and reasonable.

WHEREAS, the Commission established Docket No. 2015-103-E in which to hear the Company's request set forth in the Petition;

WHEREAS, among other statements, SCE&G states in its Petition that circumstances warrant modifying the schedules approved in the most recent Base Load Review order because in 2014 Westinghouse Electric Company ("WEC") and Chicago Bridge & Iron ("CB&I", and together with WEC, the "Consortium") reevaluated the engineering, procurement, and construction ("EPC") activities necessary to complete the Units and provided SCE&G a revised, fully-integrated construction schedule (the "Revised Fully-Integrated Construction Schedule") with an associated cash flow forecast for completion of the project (the "Revised Cash Flow Forecast");

WHEREAS, the Revised Fully-Integrated Construction Schedule reflects new substantial completion dates for Units 2 and 3 of June 19, 2019, and June 16, 2020, respectively ("Substantial Completion Dates");

WHEREAS, the updated capital cost schedule associated with the revised Substantial Completion Dates includes approximately $698 million in additional capital costs of which $245 million represents Owner's costs and $453 million represents EPC Contract costs;

WHEREAS, SCE&G has asserted, among other things, that it is not responsible for costs related to the delay in the project and that the Consortium is liable for these costs as a result of its failure to meet its responsibilities under the EPC Contract and otherwise. Nevertheless, it is clear that it will take the Consortium until June 19, 2019, and June 16, 2020, to complete Units 2 and 3, respectively, and that the additional costs reflected in the updated capital cost schedule will be incurred and are reasonable and necessary in completing the work on the Units;[1]

WHEREAS, the Consortium has not accepted responsibility for SCE&G's assertions;

WHEREAS, as set forth in the prefiled direct testimony of Stephen A. Byrne, SCE&G and the Consortium currently are engaged in active negotiations concerning the responsibility for the increased cost resulting from the delay and other disputed issues;

WHEREAS, after careful review conducted over many weeks and the performance of careful analyses using teams of experts in accounting, finance, and construction, SCE&G determined that circumstances warranted petitioning the Commission, under the BLRA, to update the approved construction schedule and the approved capital cost schedule to reflect reasonable and prudent changes to these schedules based upon the information currently available to SCE&G;[2]

WHEREAS, based on its review and analyses and as stated in its Petition, SCE&G has modified, and submitted for consideration and approval of the Commission the BLRA Milestone Construction Schedule, as reflected in Settlement Exhibit 1 attached hereto and incorporated herein by this reference, to align remaining BLRA Milestones as approved in Order No. 2012-884 to the new Substantial Completion Dates and to the current construction and fabrication schedules;

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[1] The Parties' agreement that these additional capital costs are "reasonable and necessary," in the context of the BLRA, is independent of the issue of whether SCE&G or the Consortium is ultimately responsible for the delay and associated costs, which is an issue that is governed by the EPC Agreement.

[2] In presenting the modified and updated construction and capital cost schedules as reasonable and prudent for approval under the BLRA, SCE&G does not waive, but specifically reserves, its rights against the Consortium under the EPC Contract and otherwise to dispute who is liable for the increased cost of the project, to recover damages for the delay in the Substantial Completion Dates of the Units, to continue to negotiate with the Consortium seeking to achieve fair resolutions of these disputes, and for other appropriate relief.

WHEREAS, based on its review and analyses and as stated in its Petition, SCE&G has also modified, and submitted for consideration and approval of the Commission, the capital cost schedule for completion of the Units, as reflected in Settlement Exhibit 2, attached hereto and incorporated herein by this reference, to reflect (a) the effect of the new Substantial Completion Dates on Owner's costs and EPC Contract costs, and (b) other changes in costs that have been identified since Order Exhibit No. 1 was approved by the Commission in Order No. 2012-884;

WHEREAS, S.C. Code Ann. § 58-33-277(B) (Supp. 2014) of the BLRA provides that ORS:

> shall conduct on-going monitoring of the construction of the plant and expenditure of capital through review and audit of the quarterly reports under this article, and shall have the right to inspect the books and records regarding the plant and the physical progress of construction upon reasonable notice to the utility.

WHEREAS, in connection with this case as well as since the inception of this project, ORS has exercised its rights and fulfilled its responsibilities under S.C. Code Ann. § 58-33-277 (Supp. 2014) to monitor the status of the project, by, among other things, routinely and regularly observing the progress of the plant construction and submodule production, requesting and reviewing substantial amounts of relevant financial data from the Company, auditing the quarterly reports submitted by the Company pursuant to the BLRA, inspecting the books and records of the Company regarding the plant and physical progress of construction, and reviewing in detail SCE&G's request to modify the Units' construction schedule and capital cost schedule in the above-captioned matter;

WHEREAS, SCE&G has provided information deemed satisfactory by ORS and SCEUC to support the relief requested in the Petition that the delay in the Substantial Completion Dates and other changes in construction, construction oversight, and operational readiness requirements result in necessary and reasonable modifications to the capital cost and BLRA Milestone

Construction schedule under the terms of the BLRA and are not the result of imprudence on the part of the Company;

WHEREAS, the Commission allowed for public comment and intervention in the above-captioned docket;

WHEREAS, ORS is automatically a party of record to proceeding pursuant to S.C. Code Ann. § 58-4-10(B) (Supp. 2014);

WHEREAS, SCEUC made a timely request to intervene in this docket;

WHEREAS, the Parties have varying positions regarding the issues in this case;

WHEREAS, the Parties to this Settlement Agreement have engaged in discussions to determine if a Settlement Agreement would be in their best interest; and

WHEREAS, following these discussions the Parties have each determined that their interest and the public interest would be best served by agreeing to settle the issues in the above-captioned case under the terms and conditions set forth in this Settlement Agreement;

NOW, THEREFORE, the Parties hereby stipulate and agree to the following terms:

A. STIPULATION OF SETTLEMENT AGREEMENT, TESTIMONY AND WAIVER OF CROSS-EXAMINATION

1. The Settling Parties agree to stipulate into the record before the Commission this Settlement Agreement.

2. The Settling Parties agree to stipulate into the record before the Commission the prefiled testimony and exhibits (collectively "Stipulated Testimony") of the following witnesses without objection, change, amendment, or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction consistent with this Settlement Agreement. The Settling Parties agree that no other evidence will be offered in the proceeding by them other than the Stipulated Testimony and exhibits and this Settlement Agreement unless additional evidence is necessary to support the

Settlement Agreement. The Settling Parties also reserve the right to engage in redirect examination of witnesses as necessary to respond to issues raised by the examination of their witnesses, if any, by non-Parties or by testimony filed by non-Parties.

SCE&G witnesses

1. Kevin B. Marsh
2. Stephen A. Byrne
3. Ronald A. Jones
4. Carlette L. Walker
5. Joseph M. Lynch

ORS witness:

1. M. Anthony James

If SCE&G determines that rebuttal testimony should be filed in response to any testimony filed by any Intervenor that is not a signatory to this Settlement Agreement, then the Parties hereto agree that any such testimony likewise would be stipulated into the record before the Commission under this Settlement Agreement without objection, change, amendment, or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction consistent with this Settlement Agreement.

B. SETTLEMENT TERMS

3. SCE&G has identified and itemized approximately $698 million in additional capital costs that it deems as reasonable and necessary for completion of the construction of the Units through the delayed Substantial Completion Dates. These additional capital costs have been assigned to specific cost categories and are reflected and included in Settlement Exhibit 2.

4. These modifications increase the capital cost for the Units in 2007 dollars from the approximately $4.5 billion, approved by the Commission in Order No. 2012-884, Order Exhibit No. 1 to approximately $5.2 billion. Further, along with changes in escalation rates, these

modifications increase the gross construction cost of the Units in current dollars from the approximately $5.7 billion approved by the Commission in Order No. 2012-884, Order Exhibit No. 1 to approximately $6.8 billion as reflected in Settlement Exhibit 2.

5. The Parties agree that the modified construction schedule and capital cost schedule are not the result of imprudence by SCE&G and are fully consistent with the requirements of the BLRA.

6. The Parties agree that the updated construction schedule, as reflected in the updated BLRA Milestone Construction schedule attached hereto as Settlement Exhibit 1, should be approved by the Commission as the new construction schedule.

7. The Parties also agree that the restated and updated capital cost schedule, as reflected in Settlement Exhibit 2 attached hereto, should be approved by the Commission as the new construction expenditure schedule for completion of the Units. Specifically, Settlement Exhibit 2 should replace and supersede Order Exhibit No. 1 of Order No. 2012-884.

8. By Commission Order No. 2009-104(A), the Commission established a return on equity of eleven percent (11%), which is applicable for revised rates filings under the Base Load Review Act. This return on equity has been consistently and lawfully used for each revised rates filing advanced by the Company since issuance of the initial Base Load Review order in 2009. However, as an integral part of this Settlement Agreement and for Base Load Review Act purposes only, beginning with any revised rates filing made on or after January 1, 2016, and prospectively thereafter until such time as the Units are completed, SCE&G agrees to develop and calculate its revised rates filings using ten and one-half percent (10.5%) as the return on common equity rather than the approved return on common equity of eleven percent (11%) subject to Paragraph 14 hereof.[3]

[3] Any revised rates placed into effect prior to January 1, 2016, shall not be affected by this Settlement Agreement, and the Parties specifically agree that Paragraph 8 of the Settlement Agreement is not intended to

9. As set forth in S.C. Code Ann. § 58-33-277 (Supp. 2014) of the BLRA, ORS will continue to monitor the progress of the Units' construction, including the ongoing status of negotiations between SCE&G and the Consortium of disputes related to the delayed Substantial Completion Dates and costs associated therewith.

10. The Parties agree that the terms of this Settlement Agreement are reasonable, in the public interest and in accordance with law and regulatory policy.

11. ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B) (Supp. 2014). S.C. Code Ann. § 58-4-10(B)(1) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) Economic development and job attraction and retention in South Carolina; and
> (3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

12. The Parties agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission as a fair, reasonable and full resolution of all issues in the above-captioned proceeding, and shall neither take any position contrary to the good faith duty agreed to herein nor encourage or aid any other Intervenors to take a position contrary to the terms of this Settlement Agreement. The Parties agree to use reasonable efforts to defend and support any Commission order with no

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require SCE&G to provide any offset, credit, refund, reimbursement, or other compensation to customers for rates considered and approved by the Commission and placed into effect prior to January 1, 2016. The reduction in the Company's return on equity shall only be prospectively applied for the purpose of calculating revised rates sought by the Company on and after January 1, 2016, until such time as the Units are completed and for Base Load Review Act purposes only.

other provisions issued approving this Settlement Agreement and the terms and conditions contained herein.

13. The Parties request that the Commission hold a hearing on this Settlement Agreement, pursuant to S.C. Code Ann. § 58-33-270(G) (Supp. 2014), simultaneously with the hearing on the merits of the Petition, which is currently scheduled to begin on July 21, 2015, and request that the Commission adopt this Settlement Agreement as part of its order in this proceeding. In furtherance of this request, the Parties stipulate and agree that the terms of this Settlement Agreement comport with the terms of the BLRA.

14. This Settlement Agreement contains the complete agreement of the Parties. There are no other terms and conditions to which the Parties have agreed. The Parties agree that this Settlement Agreement will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will this Settlement Agreement, or any of the matters agreed to in it, be used as evidence or precedent in any future proceeding. Any Party may withdraw from the Settlement Agreement without penalty if (i) the Commission does not approve this Settlement Agreement in its entirety or (ii) an appellate court does not affirm in all respects the Commission's order approving this Settlement Agreement in its entirety. If a Party elects to withdraw from the Settlement Agreement pursuant to this paragraph, then the provisions of this Settlement Agreement will no longer be binding upon the Parties.

15. This Settlement Agreement shall be effective upon execution by the Parties and shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to the terms and conditions of this Settlement Agreement by affixing his or her signature or authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the Settlement Agreement. Facsimile signatures and e-mail

signatures shall be as effective as original signatures to bind any party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

[Signatures on the following pages.]

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

Shannon B. Hudson

Shannon Bowyer Hudson, Esquire
Jeffrey M. Nelson, Esquire
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WE AGREE:

Representing and binding South Carolina Energy Users Committee

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WE AGREE:

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BLRA Milestones
VC Summer Units 2 and 3

Tracking ID	Order No. 2012-884 Description	Order No. 2012-884 Date	Revised Completion Date	Unit
1	Approve Engineering Procurement and Construction Agreement	Complete	Complete	
2	Issue POs to nuclear component fabricators for Units 2 & 3 Containment Vessels	Complete	Complete	
3	Contractor Issue PO to Passive Residual Heat Removal Heat Exchanger Fabricator - First Payment - Unit 2	Complete	Complete	
4	Contractor Issue PO to Accumulator Tank Fabricator - Unit 2	Complete	Complete	
5	Contractor Issue PO to Core Makeup Tank Fabricator - Units 2 & 3	Complete	Complete	
6	Contractor Issue PO to Squib Valve Fabricator - Units 2 & 3	Complete	Complete	
7	Contractor Issue PO to Steam Generator Fabricator - Units 2 & 3	Complete	Complete	
8	Contractor Issue Long Lead Material PO to Reactor Coolant Pump Fabricator - Units 2 & 3	Complete	Complete	
9	Contractor Issue PO to Pressurizer Fabricator - Units 2 & 3	Complete	Complete	
10	Contractor Issue PO to Reactor Coolant Loop Pipe Fabricator - First Payment - Units 2 & 3	Complete	Complete	
11	Reactor Vessel Internals - Issue Long Lead Material PO to Fabricator - Units 2 & 3	Complete	Complete	
12	Contractor Issue Long Lead Material PO to Reactor Vessel Fabricator - Units 2 & 3	Complete	Complete	
13	Contractor Issue PO to Integrated Head Package Fabricator - Units 2 & 3	Complete	Complete	
14	Control Rod Drive Mechanism Issue PO for Long Lead Material to Fabricator - Units 2 & 3 - first payment	Complete	Complete	
15	Issue POs to nuclear component fabricators for Nuclear Island structural CA20 Modules	Complete	Complete	
16	Start Site Specific and balance of plant detailed design	Complete	Complete	
17	Instrumentation & Control Simulator - Contractor Place Notice to Proceed - Units 2 & 3	Complete	Complete	
18	Steam Generator - Issue Final PO to Fabricator for Units 2 & 3	Complete	Complete	
19	Reactor Vessel Internals - Contractor Issue PO for Long Lead Material (Heavy Plate and Heavy Forgings) to Fabricator - Units 2 & 3	Complete	Complete	
20	Contractor Issue Final PO to Reactor Vessel Fabricator - Units 2 & 3	Complete	Complete	
21	Variable Frequency Drive Fabricator Issue Transformer PO - Units 2 & 3	Complete	Complete	
22	Start clearing, grubbing and grading	Complete	Complete	
23	Core Makeup Tank Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	Complete	
24	Accumulator Tank Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	Complete	
25	Pressurizer Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	Complete	
26	Reactor Coolant Loop Pipe - Contractor Issue PO to Fabricator - Second Payment - Units 2 & 3	Complete	Complete	
27	Integrated Head Package - Issue PO to Fabricator - Units 2 and 3 - second payment	Complete	Complete	
28	Control Rod Drive Mechanisms - Contractor Issue PO for Long Lead Material to Fabricator - Units 2 & 3	Complete	Complete	
29	Contractor Issue PO to Passive Residual Heat Removal Heat Exchanger Fabricator - Second Payment - Units 2 & 3	Complete	Complete	
30	Start Parr Road intersection work	Complete	Complete	
31	Reactor Coolant Pump - Issue Final PO to Fabricator - Units 2 & 3	Complete	Complete	
32	Integrated Heat Packages Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	Complete	
33	Design Finalization Payment 3	Complete	Complete	
34	Start site development	Complete	Complete	
35	Contractor Issue PO to Turbine Generator Fabricator - Units 2 & 3	Complete	Complete	
36	Contractor Issue PO to Main Transformers Fabricator - Units 2 & 3	Complete	Complete	
37	Core Makeup Tank Fabricator Notice to Contractor Receipt of Long Lead Material - Units 2 & 3	Complete	Complete	
38	Design Finalization Payment 4	Complete	Complete	
39	Turbine Generator Fabricator Issue PO for Condenser Material - Unit 2	Complete	Complete	
40	Reactor Coolant Pump Fabricator Issue Long Lead Material Lot 2 - Units 2 & 3	Complete	Complete	
41	Passive Residual Heat Removal Heat Exchanger Fabricator Receipt of Long Lead Material - Units 2 & 3	Complete	Complete	
42	Design Finalization Payment 5	Complete	Complete	
43	Start erection of construction buildings, to include craft facilities for personnel, tools, equipment; first aid facilities; field offices for site management and support personnel; temporary warehouses; and construction hiring office	Complete	Complete	
44	Reactor Vessel Fabricator Notice to Contractor of Receipt of Flange Nozzle Shell Forging - Unit 2	Complete	Complete	
45	Design Finalization Payment 6	Complete	Complete	
46	Instrumentation and Control Simulator - Contractor Issue PO to Subcontractor for Radiation Monitor System - Units 2 & 3	Complete	Complete	
47	Reactor Vessel Internals - Fabricator Start Fit and Welding of Core Shroud Assembly - Unit 2	Complete	Complete	
48	Turbine Generator Fabricator Issue PO for Moisture Separator Reheater/Feedwater Heater Material - Unit 2	Complete	Complete	
49	Reactor Coolant Loop Pipe Fabricator Acceptance of Raw Material - Unit 2	Complete	Complete	

BLRA Milestones
VC Summer Units 2 and 3

Tracking ID	Order No. 2012-884 Description	Order No. 2012-884 Date	Revised Completion Date	Unit
50	Reactor Vessel Internals - Fabricator Start Weld Neutron Shield Spacer Pads to Assembly - Unit 2	Complete	Complete	
51	Control Rod Drive Mechanisms - Fabricator to Start Procurement of Long Lead Material - Unit 2	Complete	Complete	
52	Contractor Notified that Pressurizer Fabricator Performed Cladding on Bottom Head - Unit 2	Complete	Complete	
53	Start excavation and foundation work for the standard plant for Unit 2	Complete	Complete	
54	Steam Generator Fabricator Notice to Contractor of Receipt of 2nd Steam Generator Tubesheet Forging - Unit 2	Complete	Complete	
55	Reactor Vessel Fabricator Notice to Contractor of Outlet Nozzle Welding to Flange Nozzle Shell Completion - Unit 2	Complete	Complete	
56	Turbine Generator Fabricator Notice to Contractor Condenser Fabrication Started - Unit 2	Complete	Complete	
57	Complete preparations for receiving the first module on site for Unit 2	Complete	Complete	
58	Steam Generator Fabricator Notice to Contractor of Receipt of 1st Steam Generator Transition Cone Forging - Unit 2	Complete	Complete	
59	Reactor Coolant Pump Fabricator Notice to Contractor of Manufacturing of Casing Completion - Unit 2	Complete	Complete	
60	Reactor Coolant Loop Pipe Fabricator Notice to Contractor of Machining, Heat Treating & Non-Destructive Testing Completion - Unit 2	Complete	Complete	
61	Core Makeup Tank Fabricator Notice to Contractor of Satisfactory Completion of Hydrotest - Unit 2	Complete	Complete	
62	Polar Crane Fabricator Issue PO for Main Hoist Drum and Wire Rope - Units 2 & 3	Complete	Complete	
63	Control Rod Drive Mechanisms - Fabricator to Start Procurement of Long Lead Material - Unit 3	Complete	Complete	
64	Turbine Generator Fabricator Notice to Contractor Condenser Ready to Ship - Unit 2	Complete	Complete	
65	Start placement of mud mat for Unit 2	Complete	Complete	
66	**Steam Generator Fabricator Notice to Contractor of Receipt of 1st Steam Generator Tubing - Unit 2**	Complete	Complete	
67	Pressurizer Fabricator Notice to Contractor of Welding of Upper and Intermediate Shells Completion - Unit 2	Complete	Complete	
68	Reactor Vessel Fabricator Notice to Contractor of Closure Head Cladding Completion - Unit 3	Complete	Complete	
69	Begin Unit 2 first nuclear concrete placement	Complete	Complete	
70	Reactor Coolant Pump Fabricator Notice to Contractor of Stator Core Completion - Unit 2	Complete	Complete	
71	Fabricator Start Fit and Welding of Core Shroud Assembly - Unit 2	Complete	Complete	
72	Steam Generator Fabricator Notice to Contractor of Completion of 1st Steam Generator Tubing Installation - Unit 2	Complete	Complete	
73	Reactor Coolant Loop Pipe - Shipment of Equipment to Site - Unit 2	Complete	Complete	
74	Control Rod Drive Mechanism - Ship Remainder of Equipment (Latch Assembly & Rod Travel Housing) to Head Supplier - Unit 2	Complete	Complete	
75	Pressurizer Fabricator Notice to Contractor of Welding of Lower Shell to Bottom Head Completion - Unit 2	Complete	Complete	
76	Steam Generator Fabricator Notice to Contractor of Completion of 2nd Steam Generator Tubing Installation - Unit 2	Complete	Complete	
77	Design Finalization Payment 14	Complete	Complete	
78	Set module CA04 for Unit 2	Complete	Complete	
79	Passive Residual Heat Removal Heat Exchanger Fabricator Notice to Contractor of Final Post Weld Heat Treatment - Unit 2	Complete	Complete	
80	Passive Residual Heat Removal Heat Exchanger Fabricator Notice to Contractor of Completion of Tubing - Unit 2	Complete	Complete	
81	Polar Crane Fabricator Notice to Contractor of Girder Fabrication Completion - Unit 2	Complete	Complete	
82	Turbine Generator Fabricator Notice to Contractor Condenser Ready to Ship - Unit 3	Complete	Complete	
83	Set Containment Vessel ring #1 for Unit 2	Complete	Complete	
84	Reactor Coolant Pump Fabricator Delivery of Casings to Port of Export - Unit 2	Complete	Complete	
85	Reactor Coolant Pump Fabricator Notice to Contractor of Stator Core Completion - Unit 3	Complete	Complete	
86	Reactor Vessel Fabricator Notice to Contractor of Receipt of Core Shell Forging - Unit 3	Complete	Complete	
87	Contractor Notified that Pressurizer Fabricator Performed Cladding on Bottom Head - Unit 3	Complete	Complete	
88	Set Nuclear Island structural module CA03 for Unit 2	6/26/2013	12/28/2015	Unit 2
89	Squib Valve Fabricator Notice to Contractor of Completion of Assembly and Test for Squib Valve Hardware - Unit 2	Complete	Complete	
90	Accumulator Tank Fabricator Notice to Contractor of Satisfactory Completion of Hydrotest - Unit 3	Complete	Complete	
91	Polar Crane Fabricator Notice to Contractor of Electric Panel Assembly Completion - Unit 2	Complete	Complete	
92	Start containment large bore pipe supports for Unit 2	Complete	Complete	
93	Integrated Head Package - Shipment of Equipment to Site - Unit 2	Complete	Complete	
94	Reactor Coolant Pump Fabricator Notice to Contractor of Final Stator Assembly Completion - Unit 2	Complete	Complete	
95	Steam Generator Fabricator Notice to Contractor of Completion of 2nd Steam Generator Tubing Installation - Unit 3	Complete	Complete	
96	Steam Generator Fabricator Notice to Contractor of Satisfactory Completion of 1st Steam Generator Hydrotest - Unit 2	Complete	Complete	
97	Start concrete fill of Nuclear Island structural modules CA01 and CA02 for Unit 2	4/3/2014	7/18/2016	Unit 2
98	Passive Residual Heat Removal Heat Exchanger - Delivery of Equipment to Port of Entry - Unit 2	Complete	Complete	
99	Refueling Machine Fabricator Notice to Contractor of Satisfactory Completion of Factory Acceptance Test - Unit 2	Complete	Complete	

BLRA Milestones
VC Summer Units 2 and 3

Tracking ID	Order No. 2012-884 Description	Order No. 2012-884 Date	Revised Completion Date	Unit
100	Deliver Reactor Vessel Internals to Port of Export - Unit 2	1/31/2014	7/30/2015	Unit 2
101	Set Unit 2 Containment Vessel #3	4/24/2014	8/23/2016	Unit 2
102	Steam Generator - Contractor Acceptance of Equipment at Port of Entry - Unit 2	Complete	Complete	
103	Turbine Generator Fabricator Notice to Contractor Turbine Generator Ready to Ship - Unit 2	Complete	Complete	
104	Pressurizer Fabricator Notice to Contractor of Satisfactory Completion of Hydrotest - Unit 3	3/31/2014	3/28/2015	Unit 3
105	**Polar Crane - Shipment of Equipment to Site - Unit 2**	1/31/2014	12/31/2015	Unit 2
106	Receive Unit 2 Reactor Vessel on site from fabricator	Complete	Complete	
107	Set Unit 2 Reactor Vessel	6/23/2014	8/9/2016	Unit 2
108	Steam Generator Fabricator Notice to Contractor of Completion of 2nd Channel Head to Tubesheet Assembly Welding - Unit 3	12/31/2013	3/30/2015	Unit 3
109	Reactor Coolant Pump Fabricator Notice to Contractor of Final Stator Assembly Completion - Unit 3	8/31/2014	10/30/2015	Unit 3
110	Reactor Coolant Pump - Shipment of Equipment to Site (2 Reactor Coolant Pumps) - Unit 2	10/31/2013	5/30/2016	Unit 2
111	Place first nuclear concrete for Unit 3	Complete	Complete	
112	Set Unit 2 Steam Generator	10/23/2014	10/10/2016	Unit 2
113	Main Transformers Ready to Ship - Unit 2	Complete	Complete	
114	Complete Unit 3 Steam Generator Hydrotest at fabricator	2/28/2014	7/30/2015	Unit 3
115	Set Unit 2 Containment Vessel Bottom Head on basemat legs	Complete	Complete	
116	**Set Unit 2 Pressurizer Vessel**	5/16/2014	8/23/2016	Unit 2
117	Reactor Coolant Pump Fabricator Notice to Contractor of Satisfactory Completion of Factory Acceptance Test - Unit 3	2/28/2015	1/31/2017	Unit 3
118	Deliver Reactor Vessel Internals to Port of Export - Unit 3	6/30/2015	12/31/2016	Unit 3
119	Main Transformers Fabricator Issue PO for Material - Unit 3	Complete	Complete	
120	Complete welding of Unit 2 Passive Residual Heat Removal System piping	2/5/2015	1/16/2017	Unit 2
121	Steam Generator - Contractor Acceptance of Equipment at Port of Entry - Unit 3	4/30/2015	1/30/2016	Unit 3
122	Refueling Machine - Shipment of Equipment to Site - Unit 3	2/28/2015	3/27/2016	Unit 3
123	Set Unit 2 Polar Crane	1/9/2015	12/19/2016	Unit 2
124	Reactor Coolant Pumps - Shipment of Equipment to Site - Unit 3	6/30/2015	4/30/2017	Unit 3
125	Main Transformers Ready to Ship - Unit 3	7/31/2015	12/30/2015	Unit 3
126	Spent Fuel Storage Rack - Shipment of Last Rack Module - Unit 3	7/31/2014	5/31/2015	Unit 3
127	Start electrical cable pulling in Unit 2 Auxiliary Building	8/14/2013	11/29/2016	Unit 2
128	Complete Unit 2 Reactor Coolant System cold hydro	1/22/2016	2/19/2018	Unit 2
129	Activate class 1E DC power in Unit 2 Auxiliary Building	3/15/2015	6/22/2017	Unit 2
130	Complete Unit 2 hot functional test	5/3/2016	5/23/2018	Unit 2
131	Install Unit 3 ring 3 for containment vessel	8/25/2015	2/27/2017	Unit 3
132	Load Unit 2 nuclear fuel	9/15/2016	12/21/2018	Unit 2
133	Unit 2 Substantial Completion	3/15/2017	6/19/2019	Unit 2
134	Set Unit 3 Reactor Vessel	10/22/2015	5/26/2017	Unit 3
135	Set Unit 3 Steam Generator #2	2/25/2016	9/22/2017	Unit 3
136	Set Unit 3 Pressurizer Vessel	7/16/2015	11/27/2017	Unit 3
137	Complete welding of Unit 3 Passive Residual Heat Removal System piping	6/16/2016	1/29/2018	Unit 3
138	Set Unit 3 polar crane	5/9/2016	12/18/2017	Unit 3
139	Start Unit 3 Shield Building roof slab rebar placement	5/26/2016	5/11/2018	Unit 3
140	Start Unit 3 Auxiliary Building electrical cable pulling	11/7/2014	6/23/2017	Unit 3
141	Activate Unit 3 Auxiliary Building class 1E DC power	5/15/2016	3/13/2018	Unit 3
142	Complete Unit 3 Reactor Coolant System cold hydro	3/22/2017	2/26/2019	Unit 3
143	Complete Unit 3 hot functional test	7/3/2017	5/26/2019	Unit 3
144	Complete Unit 3 nuclear fuel load	11/15/2017	12/19/2019	Unit 3
145	Begin Unit 3 full power operation	4/8/2018	5/20/2020	Unit 3
146	Unit 3 Substantial Completion	5/15/2018	6/16/2020	Unit 3

RESTATED and UPDATED CONSTRUCTION EXPENDITURES
(Thousands of $)

V.C. Summer Units 2 and 3 - Summary of SCE&G Capital Cost Components

Actual through December 2014* plus Projected		Actual								Projected					
Plant Cost Categories	Total	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Fixed with No Adjustment															
Firm with Fixed Adjustment A															
Firm with Fixed Adjustment B															
Firm with Indexed Adjustment															
Actual Craft Wages															
Non-Labor Costs															
Time & Materials															
Owners Costs															
Transmission Costs	329,512	-	26	724	927	11,984	51,677	58,593	47,207	64,576	64,794	30,314	710	-	-
Total Base Project Costs(2007 $)	5,246,638	21,723	97,386	319,073	374,810	314,977	488,461	448,947	422,076	742,980	759,311	658,948	389,617	169,840	38,269
Total Project Escalation	1,300,486	-	3,519	20,930	23,741	34,084	74,485	88,622	89,890	196,694	247,926	240,312	151,548	92,670	36,085
Total Revised Project Cash Flow	6,547,124	21,723	100,905	340,003	398,551	349,061	562,946	537,569	511,966	939,674	1,007,237	899,260	541,385	262,510	74,354
Cumulative Project Cash Flow(Revised)		21,723	122,629	462,632	861,183	1,210,244	1,773,190	2,310,759	2,822,725	3,762,398	4,769,835	5,668,895	6,210,280	6,472,770	6,547,124
AFUDC(Capitalized Interest)	278,790	645	3,497	10,564	17,150	14,218	18,941	27,722	26,131	30,502	44,426	39,884	30,984	11,529	3,599
Gross Construction	6,826,914	22,368	104,403	350,567	415,701	363,278	581,886	565,291	538,097	970,176	1,051,663	939,143	572,349	274,039	77,953
Construction Work in Progress		22,368	126,771	477,338	893,039	1,256,317	1,838,203	2,403,495	2,941,591	3,911,767	4,963,430	5,902,573	6,474,923	6,748,962	6,826,914

***Applicable index escalation rates for 2014 are estimated. Escalation is subject to restatement when actual indices for 2014 are final.**

Notes:
Current Period AFUDC rate applied 5.68%

Escalation rates vary from reporting period to reporting period according to the terms of Commission Order 2009-104(A).
These projections reflect current escalation rates. Future changes in escalation rates could substatially change these projections.
The AFUDC rate applied is the current SCE&G rate. AFUDC rates can vary with changes in market interest rates,
SCE&G's embedded cost of capital, capitalization ratios, construction work in process, and SCE&G's short-term debt outstanding.

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2015-54-E

May 26, 2015

IN RE:	)	
Petition of South Carolina Electric & Gas Company for Approval to Participate in a Distributed Energy Resource Program	)	**SETTLEMENT AGREEMENT**

This Settlement Agreement is made by and among: (1) the South Carolina Office of Regulatory Staff ("ORS"); (2) South Carolina Electric & Gas Company ("SCE&G" or the "Company"); (3) Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); (4) The Alliance for Solar Choice ("TASC"); (5) South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy ("SCCCL" and "SACE"); and (6) South Carolina Solar Business Alliance, LLC (collectively referred to as the "Settling Parties" and "Parties" or sometimes individually as "Party").

WHEREAS, pursuant to S.C. Code Ann. § 58-39-130, and the settlement agreement ("NEM Settlement Agreement") entered into in Docket No. 2014-246-E by the ORS, SCE&G, Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., Central Electric Power Cooperative, Inc. and The Electric Cooperatives of South Carolina, Inc., SCCCL, SACE, the South Carolina Solar Business Alliance, LLC, Sustainable Energy Solutions, LLC, Solbridge Energy, LLC, TASC, Nucor Steel-South Carolina and Frank Knapp, Jr., the Company prepared and filed a Petition (the "Petition") to establish a Distributed Energy Resource Program ("DERP") to accomplish and further the purposes and goals of the South Carolina Distributed Energy Resource Program Act ("Act 236");

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina (the "Commission") pursuant to the Act 236 codified at S.C. Code Ann. §§ 58-39-110 *et seq.*;

WHEREAS, the Settling Parties to this Settlement Agreement are parties of record in the above-captioned Docket;

WHEREAS, ORS is charged by law with the duty to represent the public interest of South Carolina pursuant to S.C. Code § 58-4-10(B);

WHEREAS, ORS reviewed the Petition filed in this Docket;

WHEREAS, the Settling Parties have varying positions regarding the issues in this case;

WHEREAS, the Parties engaged in discussions to determine if a settlement of some or all of the issues would be in their best interests and, in the case of ORS, in the public interest; and,

WHEREAS, following those discussions, the Settling Parties determined that their interests, and ORS determined that the public interest, would be best served by stipulating to a comprehensive settlement of all issues raised by the Settling Parties and pending in the above-captioned case under the terms and conditions set forth herein.

NOW, THEREFORE, the Parties hereby stipulate and agree to the following terms:

A. STIPULATION OF SETTLEMENT AGREEMENT, TESTIMONY AND WAIVER OF CROSS-EXAMINATION

A.1 The Settling Parties agree to stipulate into the record before the Commission this Settlement Agreement.

A.2 The Settling Parties agree to stipulate into the record before the Commission the pre-filed testimony and exhibits (collectively "Stipulated Testimony") of the following witnesses without objection, change, amendment, or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction consistent with this Settlement Agreement. The Settling Parties agree that no other evidence will be offered in the proceeding by them other than the Stipulated Testimony and exhibits and this Settlement Agreement unless additional evidence is necessary to support the Settlement Agreement. The Settling Parties also reserve the right to engage in redirect examination of witnesses as necessary to respond to issues raised by the examination of their witnesses, if any, by non-Parties or by late filed testimony by non-Parties.

ORS witness:
1. Lynda S. Shafer

SCE&G witnesses

1. John H. Raftery
2. Allen W. Rooks

Wal-Mart witness:
1. Kenneth E. Baker

SCCCL AND SACE witnesses:
1. Hamilton Davis
2. John D. Wilson

TASC witness
1. Justin R. Barnes

B. SETTLEMENT TERMS

B.1. As a compromise, the Settling Parties agree to the proposal set out immediately below, and this proposal is hereby adopted, accepted, and acknowledged as the agreement of the Settling Parties.

B.2. Except as set forth explicitly below in this Settlement Agreement, the Parties agree to accept all recommendations and modifications in ORS's testimony. Where the Petition and Company testimony differ from ORS testimony, ORS testimony governs.

MW Goals

B.3. The Settling Parties agree that the Company's DERP Petition is designed to meet the Company's statutorily designated goals as set by S.C. Code Ann. § 58-39-130. According to S.C. Code Ann. § 58-39-130, the Company's DERP shall, at a minimum result in development by December 31, 2020 of renewable energy facilities located in South Carolina with a nameplate capacity equal to at least two percent of the previous five-year average of the electrical utility's South Carolina retail peak demand. For SCE&G, this amount equates to approximately 84.5 megawatts ("MW"). Of this two percent, Act 236 states that half shall be met by facilities sized between one (1) and ten (10) MW, hereafter defined as "Utility Scale Program." The remaining half shall be met by facilities sized less than one (1) MW ("Customer Scale Program") with a quarter of the one percent (0.25%) nameplate capacity being from renewable energy generation 20 kilowatts ("kW") or less ("Small Scale Requirement").

Utility-Scale Program

B.4. The Settling Parties agree that the Company will make a good faith effort to have at least 30 MW of utility-scale solar capacity in service before the end of 2016. To accelerate the development of this capacity, the Company agrees to solicit proposals for utility-scale solar engineering, procurement and construction for projects that are located on non-Company owned land within SCE&G's electric service territory.

Customer Scale Program - Performance Based Incentive

B.5. The Settling Parties agree that SCE&G's DERP will include a Performance Based Incentive ("PBI") to residential customers who install solar photovoltaic facilities of not more than 20 kW AC nameplate capacity. This PBI will be provided in conjunction with the Company's net metering tariff. The PBI will be provided to residential customers for a term of ten (10) years. The PBI is prospective and retroactive for facilities constructed after January 1, 2015.

B.6. After such time that the Company's PBI reservation system is publicly available, customers must submit a PBI application prior to installation of the generating system and, upon approval, the Company will guarantee the amount of the incentive for one hundred and eighty (180) days from the date the Applicant is notified of PBI application approval. The Company will grant up to two (2) extensions of 90 days each upon written request of the Applicant, or a designated representative, such as the installer or lessor of the generating system. Customers applying for net metering after January 1, 2015, and that install or are in the process of installing a generating system prior to the time the Company's PBI reservation system is publicly available, shall have 90 days from the date the reservation system is established by the Company to apply, retroactively, for the net metering PBI and shall be treated on a first-come, first serve basis according to the date of the net metering application.

B.7. The PBI will be administered using the capacity-based step-down tiers set forth in Chart A below. Each step-down level shall be triggered when the capacity limit for a given PBI step level has been reserved by residential customer-generators. Once sufficient reservations have been secured to meet a capacity limit, the PBI shall be automatically adjusted downward for all new customers enrolling in the PBI program. The PBI program shall be open to new net metering customers through (i) December 31, 2020, or (ii) until the date on which the total capacity limit in Chart A has been met by approved PBI reservations for residential net metering customers, whichever is earlier.

Chart A

PBI Program Incentive Step-Down

Cumulative Capacity ***(Megawatts)***	**Performance Based Incentive** ***(per kWh)***
0 – 2.5	$0.04
2.5 - 5	$0.03
5 – 7.5	$0.02
7.5 - 9	$0.01

B.8. The Settling Parties agree that the Company shall update the current PBI generator capacity reservations, in kW, on its website on a monthly basis.

B.9. The Settling Parties further agree that: SCE&G's customers will be allowed to assign the right to receive payment of their PBI to a third-party installer or lessor of the solar facility and SCE&G will communicate with, and require, each customer to execute the necessary documents to effectuate such assignments.

Customer Scale Program - Bill Credit Agreements

B.10. The Settling Parties agree that as part of its DERP SCE&G will offer bill credit agreements ("BCA") to its non-residential customers but will not offer any BCA to its residential customers. Initially SCE&G will offer non-residential customers the BCA bill credit rates presented in Company witness John Raftery's direct testimony. BCA bill credit rates will be fixed and offered for a term of ten (10) years. Facilities constructed after January 1, 2015 which are eligible for BCA, credits pursuant to the customer's ten-year BCA term will begin upon the customer's acceptance into the BCA bill credit rate program, and will not be paid retroactively to the time the facility was constructed.

B.11. If capacity installed by non-residential customers participating in the BCA program is no greater than 20 kW, this capacity shall count toward the Small Scale Requirement pursuant to S.C. Code Ann. § 58-39-130(C)(2), but shall not count toward reaching the capacity-based PBI net metering program step-down levels that are set forth in Paragraph B.7 of this Settlement Agreement.

B.12. The Settling Parties agree that the Company offered BCA is available to any non-residential customer, including those who lease a solar electric generating facility from a third-party provider or those who own a solar electric generating facility.

Customer Scale Program - Lease/Finance Program

B.13. The Settling Parties agree that SCE&G will withdraw its proposal to offer a Lease/Finance Program as part of its DERP. The Settling Parties also agree that the Company may request approval of a Lease/Finance Program in the future.

Customer Scale Program - Community Solar

B.14. The Settling Parties agree that at this time capacity from SCE&G's Community Solar Program shall not count toward the Small Scale Requirement and Customer Scale Program pursuant to S.C. Code Ann. § 58-39-130(C)(2). The Company is not precluded from seeking approval from the Commission to count the Community Solar Program capacity towards satisfying the Small Scale Requirement and Customer Scale Program.

B.15. Community Solar capacity shall not impact any BCA offerings or be used in calculating the capacity-based PBI step-down levels that are set forth in Paragraph B.7 of this Settlement Agreement.

B.16. The Settling Parties agree that the Company will evaluate the per-watt price paid by a customer to ensure that it accurately reflects the developer's per-watt cost. Should the Company choose to incentivize the up-front customer costs for Community Solar, these incentives shall be deemed DER Program incremental costs.

DERP Advisory Group

B.17. The Settling Parties agree that the Company shall convene a DERP Advisory Group to use as a resource for sharing ideas and advancing the effectiveness of the Company's DERP. The DERP Advisory Group shall meet at least twice a year, and group participants shall receive notification 15 days prior to the Company filing with the Commission to add, modify or terminate any DERP offering. Pending exigent circumstances, the DERP Advisory Group may meet more than twice a year. All Settling Parties have the right to participate in the DERP Advisory Group. To the extent possible, the DERP Advisory Group shall consist of no more than twelve (12) participants, inclusive of the Company and ORS. The DERP Advisory Group participants will represent interested stakeholders with diverse viewpoints, for example those including but not limited to consumer groups, developers of large scale renewable energy, developers of small-scale renewable energy, lessors of renewable energy facilities, and environmental advocates.

B.18. The Settling Parties agree that within the first two (2) DERP Advisory Group meetings, evaluation of the viability of future incentives or offerings designed for the needs of economically disadvantaged customers will begin. Within eighteen (18) months of the date of the Settlement Agreement, the Company will propose to the Commission a DERP initiative or offering designed for the needs of economically disadvantaged customers.

B.19. The Settling Parties agree that, on or before November 1, 2015, the Company will discuss with the DERP Advisory Group a program that allows an owner of a structure with SCE&G load and meters on-site to enter a buy-all/sell-all agreement for a term of 10 years at the same rates available to customers receiving the BCA provided that the system is sized not to produce more than 100% of energy consumed by the aggregate of the existing meters on the property over the prior 12 months so long as the program is consistent with Act 236.

Renewable Energy Credits

B.20. The Settling Parties agree that the Company will retain ownership of the renewable energy credits ("RECs") until all DERP Incremental Costs are recovered by the Company and DERP charges are removed from all customer bills. At such time the system owner will begin retaining ownership of any RECs generated from that point forward.

B.21. The Settling Parties agree that all value derived by the Company from RECs be credited against DERP incremental costs or used to offset future South Carolina environmental compliance costs or requirements incurred by the Company.

DERP Modification

B.22. The Settling Parties agree that, with the exception of the pre-approved step-down method outlined in paragraph B.7, Chart A, the Company shall file for Commission approval of any program additions or terminations, and that the Company shall seek Commission approval for any program modifications that result in a variation greater than twenty-five percent (25%) of a program tariff's approved charges, incentives or credits.

Other

B.23. The Parties agree that the Company will file tariffs for each of its DERP offerings within 90 days of the issuance of a Commission Order in this Docket.

B.24. The Settling Parties agree that SCE&G will only allow a customer-generator to size their renewable generator in such a manner so that the renewable generation will off-set part, or all, of the customer's own electrical energy requirements, as determined by historic data on the customer's annual electricity usage or as estimated by SCE&G where annual usage data does not exist (e.g., new customer).

DERP Cost Recovery

B.25. The Parties agree that DERP costs shall be allocated and recovered pursuant to S.C. Code Ann. §§ 58-27-865 and 58-39-140, to the extent such costs are reasonably and prudently incurred to implement an approved program.

B.26. For purposes of cost allocation and recovery, the Parties agree that the following DERP costs shall be treated as avoided costs (instead of as incremental costs subject to the cap): (i) amounts paid under avoided cost rates or rates negotiated under the Public Utility Regulatory Policy Act ("PURPA") for purchased power agreements, and (ii) amounts paid for generation purchased at the Company's avoided cost rates from Community Solar, net metering and BCA. Though not included for recovery as avoided costs in the Company's Application, the Company may have avoided costs arising from the following areas in the future: (i) the avoided cost component of SCE&G owned generation constructed to implement a DERP, as set forth in S.C. Code Section 58-39-140, and (ii) the avoided cost component related to new programs introduced in the future to implement a DERP, as set forth in S.C. Code Ann. § 58-39-140.

B.27. The Parties agree that the Company will recover from customers avoided DERP costs using the same methodology used for the variable environmental component of the fuel factor for SCE&G's rate classes and customers.

B.28. The Parties agree that because the incremental DERP costs that may be recovered from ratepayers are capped pursuant to S.C. Code Ann. § 58-39-150, it would be reasonable for the Company to establish a fixed incremental dollar amount per-account charge ("DER Component") within its fuel factor to collect incremental DERP costs from customers not to exceed annually per account: $12 for residential; $120 for commercial; and $1,200 for industrial.

B.29. The Parties agree that for the purpose of billing the DER Component, the Company shall define an account as a single point of delivery in the same manner as SCE&G applies its basic facilities charge. For industrial customers being served on more than one large general service rate (i.e. Rate 23, Rate, 24, or Rate 27) and located on the same property, only one DER Component will be assessed.

B.30. The Parties agree that, in the event the incremental costs to be recovered from any customer class in a given year exceeds the per-account annual cost caps set forth in S.C. Code Ann. § 58-39-150, the Company will follow and use deferral accounting and may carry forward such costs in excess of the per-account annual cost caps for recovery to be reallocated among all customer classes, consistent with the methodology for allocating variable environmental costs, through the fuel factor in subsequent years as an incremental DERP cost subject to the caps. Non-capital incremental costs will be deferred with carrying costs calculated at the three-year treasury note plus 65 basis points. Incremental capital costs will be deferred using the Company's weighted average cost of capital as defined in Act 236.

C. REMAINING TERMS AND CONDITIONS

C.1 The Parties agree this Settlement Agreement is reasonable, in the public interest and in accordance with law and regulatory policy.

C.2 Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B). S.C. Code Ann. § 58-4-10(B)(1) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;

(2) Economic development and job attraction and retention in South Carolina; and

(3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

C.3 The Settling Parties agree to advocate that the Commission accept and approve this Settlement Agreement in its entirety as a fair, reasonable and full resolution of all issues in the above-captioned proceeding, and to take no action inconsistent with its adoption by the Commission.

C.4 The Settling Parties further agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission in its entirety.

C.5 This Settlement Agreement is binding on the Settling Parties only. It creates no rights in third parties nor are there third party beneficiaries to it. Only Parties who are signatories may make any claim under this Settlement Agreement.

C.6 The Settling Parties agree that signing this Settlement Agreement (a) will not constrain, inhibit, impair, waive, or prejudice their arguments or positions held in future or collateral proceedings; (b) will not constitute a precedent or evidence of acceptable practice in future proceedings; and (c) will not limit the relief, rates, recovery or rates of return that any Party may seek or advocate in any future proceeding.

C.7 If the Commission declines to approve this Settlement Agreement in its entirety, then any Party may withdraw from the Settlement Agreement without penalty or obligation within three (3) days of receiving notice of the decision, by providing written notice of withdrawal via electronic mail to all parties in that time period.

C.8 This Settlement Agreement shall be effective upon execution by the Settling Parties and shall be interpreted according to South Carolina law.

C.9 This Settlement Agreement contains the complete agreement of the Settling Parties. This Settlement Agreement shall bind and inure to the benefit of each of the signatories hereto and their representatives, predecessors, successors, assigns, agents, shareholders, officers, directors (in their individual and representative capacities), subsidiaries, affiliates, parent corporations, if any, joint ventures, heirs, executors, administrators, trustees, and attorneys.

C.10 The above terms and conditions fully represent the agreement of the Settling Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Settlement Agreement, by affixing its signature or by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement. The Settling Parties agree that in the event any Party should fail to indicate its consent to this Settlement Agreement and the terms contained herein, then this Settlement Agreement shall be null and void and will not be binding on any Party.

[THE REMAINDER OF THIS PAGE HAS BEEN LEFT INTENTIONALLY BLANK]
[SIGNATURE PAGES FOLLOW]

WE AGREE:

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WE AGREE:

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WE AGREE:

Representing and binding South Carolina Energy Users Committee

____

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WE AGREE:

Representing and binding the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy

J. Blanding Holman IV

by JJB w/permission

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WE AGREE:

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____

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WE AGREE:

Representing and binding Central Electric Power Cooperative, Inc.

____

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WE AGREE:
Representing and binding The Sierra Club

____

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BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2016-2-E

April 4, 2016

IN RE:	Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	)))	**SETTLEMENT AGREEMENT**

This Settlement Agreement is made among the South Carolina Office of Regulatory Staff ("ORS"), South Carolina Energy Users Committee, South Carolina Solar Business Alliance, LLC, South Carolina Solar Development, LLC, Southern Current, LLC, and South Carolina Electric & Gas Company ("SCE&G") (collectively referred to as the "Settling Parties" or sometimes individually as a "Settling Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina ("Commission") pursuant to the procedure established in S.C. Code Ann. § 58-27-865 (2015), and the Settling Parties to this Settlement Agreement are parties of record in the above-captioned docket;

WHEREAS, the Settling Parties have varying legal positions regarding the issues in this proceeding;

WHEREAS, the Settling Parties have engaged in discussions to determine if a settlement would be in their best interest;

WHEREAS, following these discussions the Settling Parties have each determined that their interests and the public interest would be best served by settling matters in the above-captioned case under the terms and conditions set forth below:

A. STIPULATION OF SETTLEMENT AGREEMENT, TESTIMONY, AND WAIVER OF CROSS EXAMINATION

A.1. The Settling Parties agree to stipulate into the record before the Commission this Settlement Agreement.

A.2. The Settling Parties agree to stipulate into the record before the Commission the direct testimony and exhibits of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

a. SCE&G witnesses:

i. Todd B. Johnson

ii. Joseph K. Todd

iii. Michael D. Shinn

iv. J. Darrin Kahl

v. Joseph M. Lynch

vi. Allen W. Rooks

vii. John H. Raftery

b. ORS witnesses:

i. Margaret D. Romaniello

ii. Michael L. Seaman-Huynh

iii. Lynda S. Shafer

c. S. C. Solar Business Alliance:

i. Paul Fleury

The Settling Parties further agree to stipulate into the record before the Commission the rebuttal testimony and exhibits of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

d. SCE&G witnesses:

i. Joseph M. Lynch

ii. Allen W. Rooks

iii. John H. Raftery

The Settling Parties reserve the right to engage in redirect of witnesses as may be necessary to respond to issues raised by the examination of their witnesses, if any, by non-parties or parties that are not signatories to this Settlement Agreement.

A.3. The Settling Parties agree that no other evidence will be offered in this proceeding by them other than the Stipulated Testimony and Exhibits, and this Settlement Agreement.

B. SETTLEMENT TERMS

B.1. As a compromise, the Settling Parties agree to the proposal set out immediately below, and this proposal is hereby adopted, accepted, and acknowledged as the agreement of the Settling Parties.

Avoided Costs, Net Energy Metering, and Distributed Energy Resources

B.2. As a compromise and without constraining, inhibiting, or impairing their arguments or positions in future proceedings, the Settling Parties agree to resolve the matters at issue in this proceeding by agreeing as follows:

a. The methodologies used by SCE&G to calculate its avoided energy and capacity costs under the Public Utility Regulatory Policies Act of 1978 ("PURPA") as described in the testimony of SCE&G Witness Lynch are reasonable and prudent.

b. Rate Schedules PR-1 and PR-2, attached hereto as Attachments A and B, including the rates, credits, charges, and underlying methodologies, and the terms and conditions of service, are lawful, just, and reasonable. If approved by the Commission, Rate Schedules PR-1 and PR-2 shall become effective for the period beginning with the first billing cycle for May 2016.

c. The updated components of value for Net Energy Metering ("NEM") Distributed Energy Resources as shown in Table 6 on corrected page 23 in the testimony of SCE&G Witness Lynch and listed below are reasonable and prudent, comply with the NEM methodology approved by the Commission in Order No. 2015-194, properly evaluate and/or quantify all categories of potential costs or benefits to SCE&G's system, and satisfy the requirements of S.C. Code Ann. § 58-40-10, *et seq*. (2015).

	Current Period ($/kWh)	IRP Planning Horizon (15-Year Levelized) ($/kWh)	Components
1	$0.02984	$0.03201	Avoided Energy Costs
2	$0	$0.00600	Avoided Capacity Costs
3	$0	$0	Ancillary Services
4	$0	$0	T & D Capacity
5	$0.00006	$0.00006	Avoided Criteria Pollutants
6	$0	$0	Avoided CO_2 Emission Cost
7	$0	$0	Fuel Hedge
8	$0	$0	Utility Integration & Interconnection Costs
9	$0	$0	Utility Administration Costs
10	$0	$0	Environmental Costs
11	$0.02990	$0.03807	Subtotal
12	$0.00251	$0.00319	Line Losses @ 0.9226
13	$0.03241	$0.04126	**Total Value of NEM Distributed Energy Resources**

d. SCE&G's proposed revisions to its "Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities" tariff sheet, attached hereto as Attachment C, including the rates, terms, and conditions, are lawful, just, and reasonable, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2016.

e. SCE&G's calculation and method of accounting for avoided and incremental costs for NEM during the review period of January 1, 2015, through December 31, 2015, were reasonable and prudent, were consistent with methodology approved in Commission Order No. 2015-194, and complied with S.C. Code Ann. § 58-40-10, *et seq.* (2015).

f. During the review period of January 1, 2015, through December 31, 2015, SCE&G offered Distributed Energy Resource ("DER") programs and took steps to fulfill its DER goals approved by the Commission in Order No. 2015-194, which programs and steps were reasonable and prudent, complied with Commission Order Nos. 2015-194 and 2015-512, and were designed to meet SCE&G's statutorily designated goals as set by S.C. Code Ann. § 58-39-130 (2015).

g. As a result of SCE&G's efforts to provide the DER programs, the balance of the DER program costs as of December 31, 2015, totaled $2,035 in avoided costs and $729,474 in incremental costs, which costs are reasonable and prudent.

h. SCE&G reasonably projected its DER program costs for the period January 1, 2016, through April 30, 2017, which projected costs include $2,390,670 in avoided costs and $4,479,822 in incremental costs.

i. SCE&G's proposed DER Avoided Cost Component by class, as set forth below, are reasonable and prudent, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2016.

Class	DER Avoided Cost Component (cents/kWh)
Residential	0.015
Small General Service	0.012
Medium General Service	0.011
Large General Service	0.007

j. SCE&G's proposed monthly per account DER Incremental Cost Component by class, as set forth below, properly allocates SCE&G's DER program incremental costs, are reasonable and prudent, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2016.

Class	Monthly Per Account DER Incremental Cost Component
Residential	$ 0.34
Small & Medium Gen. Svc.	$ 1.27
Large General Service	$ 100.00

k. SCE&G's proposed "Adjustment for Fuel, Variable Environmental, & Avoided Capacity, and Distributed Energy Resource Program Costs" tariff sheet, attached hereto as Attachment D, including the rates, terms, and conditions, is lawful, just, and reasonable, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2016.

<u>Fuel Expenses and Power Plant Operations</u>

B.3. ORS's review of SCE&G's operation of its generating facilities resulted in ORS concluding that SCE&G has made reasonable efforts to maximize unit availability and minimize fuel costs. Additionally, ORS has determined that SCE&G took appropriate corrective action with respect to outages that occurred during the review period of January 1, 2015, through December 31, 2015. Further, ORS has concluded that, subject to the adjustments set forth in its pre-filed direct testimony, SCE&G's accounting practices are in compliance with S.C. Code Ann. § 58-27-865 (2015).

B.4 The Settling Parties agree to accept all recommendations, if any, in ORS Witnesses Romaniello's and Seaman-Huynh's testimonies and exhibits pertaining to SCE&G's fuel expenses and power plant operations for the periods January 1, 2015, through December 31, 2015 ("Actual Period"), and January 1, 2016, through April 30, 2016 ("Estimated Period"), as well as forecasted data for the period May 1, 2016 through April 30, 2017 ("Forecasted Period"). Accordingly, SCE&G's net cumulative over-recovered balance of total base fuel, variable environmental, and avoided capacity costs for the periods ending December 31, 2015, and projected through April 30, 2016, are $25,667,141 and $61,020,158, respectively. As of December 31, 2015, the net cumulative over-recovered balance of $25,667,141 consists of cumulative over-recovered base fuel costs of $21,307,142 and cumulative over-recovered environmental and avoided capacity costs of $4,359,999. As of April 30, 2016, the projected net cumulative over-recovered balance of $61,020,158 consists of cumulative over-recovered base fuel costs of $55,924,568 and cumulative over-recovered environmental and avoided capacity costs of $5,095,590.

Fuel Factors

B.5. The Settling Parties agree that the appropriate fuel factors for SCE&G to charge pursuant to this Settlement Agreement for the period beginning with the first billing cycle for May 2016 and extending through the last billing cycle for April 2017 are listed below and set forth in the tariff sheet entitled "Adjustment for Fuel, Variable Environmental, and Avoided Capacity Costs," which is attached hereto as Attachment D.

Class	Base Fuel Cost Component (cents/kWh)	DERP Avoided Cost Component	Environmental Fuel & Avoided Capacity Component (cents/kWh)	Total Fuel Costs Factor (cents/kWh)
Residential	2.445	0.015	0.032	2.492
Small General Service	2.445	0.012	0.026	2.483
Medium General Service	2.445	0.011	0.024	2.480
Large General Service	2.445	0.007	0.017	2.469
Lighting	2.445	0.000	0.000	2.445

B.6. The Settling Parties agree that the total fuel costs factors set forth in Paragraph B.5 above are projected to eliminate SCE&G's over-collected balance of total fuel costs as of April 30, 2017.

B.7. If approved by the Commission, the proposed rates would decrease the average monthly bill for a residential customer on Rate 8 using 1,000 kWh by approximately $6.87, from $149.58 to $142.71.

B.8. The Settling Parties agree the fuel factors set forth above are consistent with S.C. Code Ann. § 58-27-865 (2015). The Settling Parties further agree that, except as provided in Paragraph B.2 and C.4 herein, any and all challenges to SCE&G's historical fuel costs recovery for the period ending December 31, 2015, are not subject to further review; however, the projected fuel costs for the period beginning January 1, 2016, and thereafter, shall be an open issue in future fuel costs proceedings held under the procedure and criteria established in S.C. Code Ann. § 58-27-865 (2015).

Other

B.9. With regards to plant outages not completed as of December 31, 2015, if any, and outages where final reports of SCE&G, contractors, governmental entities or others are not available, if any, the Settling Parties agree that ORS retains the right to review the reasonableness of the plant outage(s) and associated costs in the review period during which the outage is completed or when the report(s) on such outage(s) become available.

B.10. Upon written request, SCE&G will provide the following to the Settling Parties:

a. Copies of the monthly fuel recovery reports currently filed with the Commission and ORS; and,

b. Quarterly forecasts beginning with the quarter ending June 30, 2016, of the expected fuel factors to be set at SCE&G's next annual fuel proceeding and SCE&G's historical over (under)-recovered balance to date. SCE&G agrees it will put forth reasonable efforts to forecast the expected fuel factors to be set at its next annual fuel proceeding; however, the Settling Parties agree that these quarterly forecasts will not be admitted into evidence in any future SCE&G proceeding.

C. REMAINING SETTLEMENT TERMS AND CONDITIONS

C.1 The Settling Parties agree this Settlement Agreement is reasonable, in the public interest, and in accordance with law and regulatory policy. This Settlement Agreement in no way constitutes a waiver or acceptance of the position of any Settling Party concerning the requirements of S.C. Code Ann. § 58-27-865 (2015) in any future proceeding.

C.2. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B) (2015). S.C. Code Ann. § 58-4-10(B)(1) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) Economic development and job attraction and retention in South Carolina; and
> (3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

C.3. The Settling Parties agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission as a fair, reasonable, and full resolution in the above-captioned proceeding. The

Settling Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Settlement Agreement and the terms and conditions contained herein.

C.4. This written Settlement Agreement contains the complete agreement of the Settling Parties. There are no other terms and conditions to which the Settling Parties have agreed. This Settlement Agreement integrates all discussions among the Settling Parties into the terms of this written document. The Settling Parties agree that this Settlement Agreement will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will this Settlement Agreement or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If the Commission should decline to approve this Settlement Agreement in its entirety, then any Settling Party desiring to do so may withdraw from this Settlement Agreement without penalty.

C.5. This Settlement Agreement shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Settling Parties hereto. Therefore, each Settling Party acknowledges its consent and agreement to this Settlement Agreement by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Settling Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

[PARTY SIGNATURES TO FOLLOW ON SEPARATE PAGES]

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____

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Representing and binding Southern Current, LLC

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ATTACHMENT A

SOUTH CAROLINA ELECTRIC & GAS COMPANY **ELECTRICITY**

RATE PR-1 **SMALL POWER PRODUCTION, COGENERATION**

AVAILABILITY

Available to Small Power Producers and Cogenerators that are a Qualifying Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54. This schedule is not available for Qualifying Facilities that have power production capacity greater than 100 KW.

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATE
(Seller Charges & Credits)

For Qualifying Facilities, Company will pay Seller a monthly credit equal to the Energy Credit and the Capacity Credit reduced by the Seller Charge.

I. Energy Credit:

Company shall pay Seller the following rates per KWH for energy delivered by the Seller to Company's system.

		Summer (June -September)	Winter (October-May)
1.	On-Peak	$0.03274	$0.03525
2.	Off-Peak	$0.02662	$0.03379

The South Carolina Power Excise Tax of $.0005 per KWH is included in the energy credits above.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS FOR ENERGY CREDITS

A. On-Peak Hours:

Summer Months of June - September:

The on-peak Summer hours are defined to be 10:00 a.m.-10:00 p.m. Monday-Friday.

Winter Months of October - May:

1. November through April: The on-peak hours are defined as those hours between 6:00 a.m.-1:00 p.m. and 5:00 p.m.-10:00 p.m., Monday-Friday.
2. October and May: The on-peak hours are defined as those hours between 10:00 a.m.-10:00p.m., Monday-Friday.

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

II. Capacity Credit:

In addition to the energy credit, the Company shall pay the Seller $0.06466 per kWh for energy delivered by the Seller to the Company's system during critical peak Summer hours. The Company shall pay the Seller $0.02190 per kWh for energy delivered by the Seller to the Company's system during critical peak Winter hours.

DETERMINATION OF CRITICAL PEAK HOURS FOR CAPACITY CREDITS

A. Critical Peak Hours:

Summer Months of June - August:

The critical peak Summer hours are defined to be 2:00 p.m. - 6:00 p.m. Monday-Friday.

Winter Months of December - February:

The critical peak Winter hours are defined to be 6:00 a.m. - 9:00 a.m. Monday-Friday.

III. Seller Charge:

Seller shall pay the following Seller Charge each monthly billing period $ 4.50

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from Qualifying Facility until such facility and Company have executed an Agreement for Purchase of Power from Small Power Production facility or Cogeneration Facility.

Effective Upon Approval of the
Public Service Commission of South Carolina

AVAILABILITY

Available to Small Power Producers and Cogenerators that are a Qualifying Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54 that have power production capacity greater than 100 kW and less than or equal to 80 MW, and entering into a power purchase agreement ("Seller") with South Carolina Electric & Gas Company. This schedule is not available for Qualifying Facilities that have power production capacity greater than 80 MW or equal to or less than 100 KW.

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATES

For a Qualifying Facility as described in the Availability section above, the Company will pay Seller an amount equal to the Energy Payment and the Capacity Payment reduced by the Seller Charge. The Company will pay this amount monthly.

I. **Energy Payment:**

Company shall pay the Seller the following rates per kWh for energy delivered by the Seller to Company's system:

A. For the period 2016 - 2020:

		For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
		Summer (Jun. - Sep.)	Non-Summer (Oct. - May)	Summer (Jun. - Sep.)	Non-Summer (Oct. - May)
1.	On-Peak	$ 0.03385	$ 0.03189	$ 0.03385	$ 0.03189
2.	Off-Peak	$ 0.02757	$ 0.03162	$ 0.02757	$ 0.03162

B. For the period 2021 - 2025:

		For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
		Summer (Jun. - Sep.)	Non-Summer (Oct. - May)	Summer (Jun. - Sep.)	Non-Summer (Oct. - May)
1.	On-Peak	$ 0.03316	$ 0.03178	$ 0.03316	$ 0.03178
2.	Off-Peak	$ 0.02682	$ 0.02615	$ 0.02682	$ 0.02615

C. For the period 2026 - 2030:

		For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
		Summer (Jun. - Sep.)	Non-Summer (Oct. - May)	Summer (Jun. - Sep.)	Non-Summer (Oct. - May)
1.	On-Peak	$ 0.03861	$ 0.03913	$ 0.03861	$ 0.03913
2.	Off-Peak	$ 0.03042	$ 0.03294	$ 0.03042	$ 0.03294

The South Carolina Power Excise Tax of $.0005 per kWh is included in the energy payments above.

Transmission Level is defined as voltages equal to or greater than 33 kV. Distribution Level is defined as voltages less than 33 kV.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS FOR ENERGY PAYMENTS

A. On-Peak Hours:

Summer Months of June - September:

The on-peak Summer hours are defined to be 10:00 a.m. - 10:00 p.m. Monday-Friday.

Non-Summer Months of October - May:

1. November through April: The on-peak hours are defined as those hours between 6:00 a.m. - 1:00 p.m. and 5:00 p.m. - 10:00 p.m., Monday-Friday.
2. October and May: The on-peak hours are defined as those hours between 10:00 a.m. - 10:00p.m., Monday - Friday.

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

ATTACHMENT B

II. Capacity Payment:

In addition to the energy payment, the Company shall pay the Seller the following capacity payment per kWh for energy delivered by the Seller to the Company's system during Critical Peak hours.

For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
Summer (Jun. - Aug.)	Winter (Dec. - Feb.)	Summer (Jun. - Aug.)	Winter (Dec. - Feb.)
$ 0.06466	$ 0.02190	$ 0.06466	$ 0.02190

Transmission Level is defined as voltages equal to or greater than 33 kV. Distribution Level is defined as voltages less than 33 kV.

DETERMINATION OF CRITICAL PEAK HOURS FOR CAPACITY PAYMENTS

A. Critical Peak Hours:

Summer Months of June - August:

The critical peak Summer hours are defined to be 2:00 p.m. - 6:00 p.m. Monday-Friday.

Winter Months of December - February:

The critical peak Winter hours are defined to be 6:00 a.m. - 9:00 a.m. Monday-Friday.

III. Seller Charge:

Seller shall pay the following Seller Charge each monthly billing period: $ 45.00

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month for an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from a Qualifying Facility until such facility and Company have executed a power purchase agreement.

RIDER TO RETAIL RATES

NET ENERGY METERING FOR RENEWABLE ENERGY FACILITIES ("NEM")
(Page 1 of 4)

AVAILABILITY

This rider is available in conjunction with the Company's Retail Electric Service Rates, for a Customer-Generator. The customer's generating system must be manufactured, installed and operated in accordance with governmental and industry standards and must fully conform with the Company's current interconnection standards as approved by the Public Service Commission of South Carolina.

This rider is available on a first come, first serve basis until the total nameplate generating capacity of net energy metering systems equals 2% of the previous five-year average of the Company's South Carolina retail electric peak demand.

CHARACTER OF SERVICE

The applicable character of service is specific to the rate schedule that the customer receives service under.

RATE PER MONTH

The applicable rate per month shall be from the appropriate rate schedule as referenced in the availability section above. The monthly bill shall be determined as follows:

For electric service under a time-of-use rate schedule:

1. The basic facilities charge shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

2. Any demand charges shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

3. If a customer-generator's energy consumption exceeds the electricity provided by the customer-generator during a monthly billing period, the customer-generator shall be billed in kWh for the net electricity supplied by the Utility.

   If a customer-generator's energy generation exceeds the electricity provided by the Utility during a monthly billing period, the customer-generator shall be credited for the excess kWh generated during that billing period.

   Energy charges (or credits) shall be based on the rates in the applicable rate schedules as described in the availability section above. For on-peak energy, the customer's monthly usage amount in kilowatt-hours shall be reduced by the total of (a) any on-peak excess energy delivered to the Company in the current month plus (b) any accumulated on-peak excess energy balance remaining from prior months. Total on-peak energy in kilowatt-hours billed to customers shall never be less than zero. For off-peak energy, the customer's monthly usage shall be reduced by the total of (a) any off-peak excess energy delivered to the Company in the current month plus (b) any accumulated off-peak excess energy balance remaining from prior months plus (c) any accumulated on-peak excess energy balance from the current month or prior months that was not used to reduce on-peak usage. Total off-peak energy in kilowatt-hours billed to customers shall also never be less than zero. For any billing month during which excess energy exceeds the customer's usage in total, producing a net credit, the respective energy charges for the billing month shall be zero. Any excess energy credits shall carry forward on the following month's bill by first applying excess on-peak kWh against on-peak kWh charges and excess off-peak kWh against off-peak kWh charges, then applying any remaining on-peak kWh against any remaining off-peak kWh charges. Credits shall not offset the basic facilities charge or the demand charge for the applicable rate schedule.

4. Excess energy not used in the current billing month to reduce billed kWh usage shall be accumulated and used to reduce usage in future months. For all affected billing statements rendered during November billing cycles, any accumulated excess energy not used to reduce billed kWh usage shall be paid to the customer-generator at the Company's avoided cost, zeroing out the customer generator's account of excess energy. The avoided cost is the off-peak winter energy credit as approved in the Company's Rate PR-1, Small Power Production and Cogeneration schedule.

For electric service under a standard, non time-of-use rate schedule:

1. The basic facilities charge shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

2. Any demand charges shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

3. If a customer-generator's energy consumption exceeds the electricity provided by the customer-generator during a monthly billing period, the customer-generator shall be billed in kWh for the net electricity supplied by the Utility.

   If a customer-generator's energy generation exceeds the electricity provided by the Utility during a monthly billing period, the customer-generator shall be credited for the excess kWh generated during that billing period.

   Energy charges (or credits) shall be based on the rates in the applicable rate schedules as described in the availability section above. For purposes of calculating monthly energy, the customer's usage shall be reduced by the total of (a) any excess energy delivered to the Company in the current month plus (b) any accumulated excess energy balance remaining from prior months. Total energy in kilowatt-hours billed to customers shall never be less than zero. For any billing month during which excess energy exceeds the customer's usage in total, producing a net credit, the respective energy charges for the billing month shall be zero. Credits shall not offset the basic facilities charge or the demand charge for the applicable rate schedule.

4. Excess energy not used in the current billing month to reduce billed kWh usage shall be accumulated and used to reduce usage in future months. For all affected billing statements rendered during November billing cycles, any accumulated excess energy not used to reduce billed kWh usage shall be paid to the customer-generator at the Company's avoided cost, zeroing out the customer generator's account of excess energy. The avoided cost is the off-peak winter energy credit as approved in the Company's Rate PR-1, Small Power Production and Cogeneration schedule.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge plus the demand charge, if any, as stated in the applicable rate.

DEFINITIONS

1. Customer-Generator means the owner, operator, lessee, or customer-generator lessee of an electric energy generation unit which:

   (A) generates electricity from a Renewable Energy Resource;
   (B) has an electrical generating system with a capacity of:
      (i) not more than the lesser of one thousand kilowatts (1,000 kW AC) or one hundred percent (100%) of contract demand if a non-residential customer; or
      (ii) not more than twenty kilowatts (20 kW AC) if a residential customer;
   (C) is located on a single premises owned, operated, leased, or otherwise controlled by the customer;
   (D) is interconnected and operates in parallel phase and synchronization with an electrical utility and complies with the applicable interconnection standards;
   (E) is intended primarily to offset part or all of the customer-generator's own electrical energy requirements; and
   (F) meets all applicable safety, performance, interconnection, and reliability standards established by the commission, the National Electrical Code, the National Electrical Safety Code, the Institute of Electrical and Electronics Engineers, Underwriters Laboratories, the federal Energy Regulatory Commission, and any local governing authorities.

2. Renewable Energy Resource means solar photovoltaic and solar thermal resources, wind resources, hydroelectric resources, geothermal resources, tidal and wave energy resources, recycling resources, hydrogen fuel derived from renewable resources, combined heat and power derived from renewable resources, and biomass resources.

3. Retail Electric Service Rates shall mean Rates 1, 2, 3, 5, 6, 7, 8, 9 (metered), 11, 12, 13, 14, 16, 20, 21, 21A, 22, 23, 24, and 28.

4. Excess energy delivered to the Company shall be defined as energy produced by the customer's renewable energy generating facility that exceeds the energy delivered by the Company during a given time period. This excess energy shall be used to reduce energy delivered and billed by the Company during the current or a future month, as provided in the Rate Per Month section above.

5. The On-Peak and Off-Peak periods shall be defined in the applicable time-of-use rate schedules.

GENERAL PROVISIONS

1. To qualify for this rider, the customer must first qualify for and be served on one of the rate schedules as described in the availability section above. The customer must also meet all other qualifications as outlined in the availability section above.

2. All provisions of the applicable rate schedules described above including, but not limited to Billing Demand, Determination of On- and Off-Peak Hours, Adjustment for Fuel Costs, Demand Side Management Component, Pension Costs Component, Storm Damage Component, Sales and Franchise Tax, Payment Terms, and Special Provisions will apply to service supplied under this rider.

3. Customers electing service under this NEM Rider are eligible to remain on the Rider until December 31, 2025, or until such time as the customer elects to terminate service under the Rider, whichever occurs first. The rates set forth here are subject to Commission Order No. 2015-194 in Docket No. 2014-246-E entered under the terms of S.C. Code § 58-40-20(F)(4). Eligibility for this rate will terminate as set forth in Order No. 2015-194. The value of distributed energy resource generation shall be computed using the methodology contained in Commission Order No. 2015-194 in Docket No. 2014-246-E and updated annually coincident in time with the Company's filing in the fuel clause. The value for the period May 2016 – April 2017 is $0.04126 per kWh.

4. Service on this NEM Rider will be closed to new participants as of January 1, 2021, or after statutory caps described in S.C. Code Ann. § 58-39-130 have been reached, whichever occurs first.

5. When no contract demand level is available for a non-residential customer, connected load as determined by the Company shall be used as a proxy for contract demand when determining the capacity of the electrical generating system.

6. Customers who elect NEM service after January 1, 2021, will receive service in accordance with the NEM tariff in effect at the time at which the customer requests NEM service.

7. Customers served under this rider are not eligible for the Company's Small Power Production, Cogeneration Rate PR-1.

8. The customer must execute an application to interconnect generation and an interconnection agreement prior to receiving service under this rider.

9. The Company will retain ownership of Renewable Energy Credits ("RECs").

10. In the event the Company determines that it is necessary to increase the capacity of facilities beyond those required to serve the Customer's electrical requirement or to install a dedicated transformer or other equipment to protect the safety and adequacy of electric service provided to other customers, the Customer shall pay the estimated cost of the required transformer or other equipment above the estimated cost which Company would otherwise have normally incurred to serve the Customer's electrical requirement, in advance of receiving service under this Rider.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

METERING REQUIREMENTS

Customer must furnish, install, own, and maintain a meter socket to measure 100% of the Customer's generator output and that is connected on the Customer's side of the delivery point. Company will furnish, install, own, and maintain a generation meter. Company will also furnish, install, own and maintain a bi-directional billing meter to measure the kWh delivered from Company to Customer and to measure kWh received from Customer by Company. The billing meter will be configured for demand and/or time-of-use measurement as required by the applicable rate. All metering shall be at a location that is approved by the Company. At Company's sole option, the generator meter requirement may be waived for customers served under a net metering rider on or before December 31, 2015.

TERM OF CONTRACT

Contracts shall be for a period not to exceed the term of the contract under which the customer currently receives electric service. There shall be a separate contract for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are part of this rider.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

APPLICABILITY

This adjustment is applicable to and is part of the Utility's South Carolina retail electric rate schedules.

The fuel, variable environmental & avoided capacity, and DER avoided costs, to be recovered in an amount rounded to the nearest one-thousandth of a cent per kilowatt-hour, will be determined by the following formulas:

$$F_C = \frac{E_F}{S} + \frac{G_F}{S_1}$$

$$F_{EC} = \frac{E_{EC} + G_{EC}}{S_2}$$

$$F_{AC} = \frac{E_{AC} + G_{AC}}{S_2}$$

Total Fuel Rate

$$\textbf{per kWh} = F_C + F_{EC} + F_{AC}$$

Where:

F_C = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one-thousandth of a cent.

E_F = Total projected system fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

PLUS

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel costs associated with energy purchased are identifiable and are identified in the billing statement, and also including avoided energy costs incurred by the Utility. Also, the cost of "firm generation capacity purchases," which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. Costs of "firm generation capacity purchases" includes the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

PLUS

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing Utility's avoided variable costs for the generation of an equivalent quantity of electric power.

Energy receipts that do not involve money payments such as diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

MINUS

(D) The cost of fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G_F = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E_F and S.

S_1 = Projected jurisdictional kilowatt-hour sales, for the period covered by the fuel costs included in E_F.

F_{EC} = Customer class variable environmental and avoided capacity costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

E_{EC} = The projected variable environmental costs including: a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, plus b) the cost of emission allowances, as used, including allowances for SO2, NOx, mercury and particulates minus net proceeds of sales of emission allowances, and c) as approved by the Commission, all other variable environmental costs incurred in relation to the consumption of fuel and air emissions caused thereby, including but not limited to environmental reagents, other environmental allowances, and emission related taxes. Any environmental related costs recovered through intersystem sales would be subtracted from the totals produced by subparts a), b), and c). This component also includes avoided capacity costs incurred by the Utility.

These environmental and avoided capacity costs will be allocated to retail customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{EC} = Cumulative difference between jurisdictional customer class environmental fuel revenues billed and jurisdictional customer class environmental costs at the end of the month preceding the projected period utilized in E_{EC} and S_2.

F_{AC} = Customer class DER avoided costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

E_{AC} = The projected DER avoided costs paid to distributed generators as most recently determined by the Public Service Commission of South Carolina. These avoided costs will be allocated to retail electric customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{AC} = Cumulative difference between jurisdictional customer class avoided cost revenues billed and jurisdictional customer class avoided costs at the end of the month preceding the projected period utilized in E_{AC} and S_2.

S_2 = The projected jurisdictional customer class kilowatt-hour sales.

The appropriate revenue-related tax factor is to be included in these calculations.

FUEL RATES PER KWH BY CLASS

The total fuel costs in cents per kilowatt-hour by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2016 through April, 2017:

Customer Class	F_C Rate	+	F_{EC} Rate	+	F_{AC} Rate	=	Total Fuel Rate
Residential	2.445		0.032		0.015		2.492
Small General Service	2.445		0.026		0.012		2.483
Medium General Service	2.445		0.024		0.011		2.480
Large General Service	2.445		0.017		0.007		2.469
Lighting	2.445		0.000		0.000		2.445

The incremental costs associated with SCE&G's Distributed Energy Resource Programs, to be recovered in an amount rounded to the nearest cent per account, will be determined by the following formulas:

Total Fuel Rate per Account

$$F_{IC} = \frac{E_{DC} + G_{DC}}{C}$$

Where:

F_{IC} = Fuel cost per account included in base rate, rounded to the nearest cent, not to exceed \$12 for residential customers, \$120 for small/medium general service customers, and \$1,200 for large general service customers.

E_{DC} = The projected incremental costs associated with SCE&G's Distributed Energy Resource Program as determined by the Public Service Commission of South Carolina

G_{DC} = Cumulative difference between jurisdictional customer class distributed energy component revenues billed and jurisdictional customer class incremental costs associated with SCE&G's Distribued Energy Resource Program at the end of the month preceding the projected period utilized in E_{DC} and C.

C = The jurisdictional customer class account totals.

FUEL RATES PER ACCOUNT PER MONTH BY CLASS

The total fuel costs in dollars per account by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2016 through April, 2017:

Customer Class		F_{IC} Rate
Residential	$	0.34
Small & Medium General Service	$	1.27
Large General Service	$	100.00

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2017-2-E

March 30, 2017

IN RE: Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	)))	**SETTLEMENT AGREEMENT**

This Settlement Agreement is made among the South Carolina Office of Regulatory Staff ("ORS"), South Carolina Energy Users Committee, and South Carolina Electric & Gas Company ("SCE&G" or "Company") (collectively referred to as the "Settling Parties" or sometimes individually as a "Settling Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina ("Commission") pursuant to the procedure established in S.C. Code Ann. § 58-27-865 (2015), and the Settling Parties to this Settlement Agreement are parties of record in the above-captioned docket;

WHEREAS, the Settling Parties have varying legal positions regarding the issues in this proceeding;

WHEREAS, the Settling Parties have engaged in discussions to determine if a settlement would be in their best interest;

WHEREAS, following these discussions the Settling Parties have each determined that their interests and the public interest would be best served by settling matters in the above-captioned case under the terms and conditions set forth below:

A. STIPULATION OF SETTLEMENT AGREEMENT, TESTIMONY, AND WAIVER OF CROSS EXAMINATION

A.1. The Settling Parties agree to stipulate into the record before the Commission this Settlement Agreement.

A.2. The Settling Parties agree to stipulate into the record before the Commission the direct testimony and exhibits of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

a. SCE&G witnesses:

i. George A. Lippard, III

ii. Keith C. Coffer, Jr.

iii. Michael D. Shinn

iv. Henry E. Delk, Jr.

v. Joseph M. Lynch

vi. Allen W. Rooks

vii. John H. Raftery

viii. John S. Beier

b. ORS witnesses:

i. Willie J. Morgan

ii. Robert A. Lawyer

iii. Gaby Smith

iv. Brian Horri

The Settling Parties further agree to stipulate into the record before the Commission the rebuttal testimony of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

c. SCE&G witnesses:

   i. Joseph M. Lynch

   ii. John H. Raftery

The Settling Parties reserve the right to engage in redirect of witnesses as may be necessary to respond to issues raised by the examination of their witnesses, if any, by non-parties or parties that are not signatories to this Settlement Agreement.

A.3. The Settling Parties agree that no other evidence will be offered in this proceeding by them other than the Stipulated Testimony and Exhibits, and this Settlement Agreement, unless such evidence is required to respond to an issue raised by a non-settling party.

B. SETTLEMENT TERMS

B.1. As a compromise, the Settling Parties agree to the proposal set out immediately below, and this proposal is hereby adopted, accepted, and acknowledged as the agreement of the Settling Parties.

Avoided Costs, Net Energy Metering, and Distributed Energy Resources

B.2. As a compromise and without constraining, inhibiting, or impairing their arguments or positions in future proceedings, the Settling Parties agree to resolve the matters at issue in this proceeding by agreeing as follows:

a. The methodologies used by SCE&G to calculate its avoided energy and avoided capacity costs under the Public Utility Regulatory Policies Act of 1978 ("PURPA") as described in the testimony of SCE&G witness Lynch are reasonable and prudent.

b. Rate Schedules PR-1 and PR-2, attached hereto as Attachments A and B, including the rates, credits, charges, and underlying methodologies, and the terms and conditions of service, are lawful, just, and reasonable. If approved by the Commission, Rate Schedules PR-1 and PR-2 shall become effective for the period beginning with the first billing cycle for May 2017.

c. The updated components of value for Net Energy Metering ("NEM") Distributed Energy Resources ("DER") as shown in Table 6 on page 15 in the testimony of SCE&G witness Lynch and listed below are reasonable and prudent, comply with the NEM methodology approved in Commission Order No. 2015-194, properly evaluate and/or quantify all categories of potential costs or benefits to SCE&G's system, and satisfy the requirements of S.C. Code Ann. § 58-40-10, *et seq.* (2015).

	Current Period ($/kWh)	**IRP Planning Horizon (15-Year Levelized) ($/kWh)**	**Components**
1	$0.03273	$0.03199	Avoided Energy Costs
2	$0	$0.00172	Avoided Capacity Costs
3	$0	$0	Ancillary Services
4	$0	$0	T & D Capacity
5	$0.00004	$0.00004	Avoided Criteria Pollutants
6	$0	$0	Avoided CO_2 Emission Cost
7	$0	$0	Fuel Hedge
8	$0	$0	Utility Integration & Interconnection Costs
9	$0	$0	Utility Administration Costs
10	$0	$0	Environmental Costs
11	$0.03277	$0.03376	Subtotal
12	$0.00268	$0.00276	Line Losses @ 0.9245
13	$0.03545	$0.03651	**Total Value of NEM Distributed Energy Resources**

d. SCE&G's proposed revisions to its "Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities" tariff sheet, attached hereto as Attachment C, including the rates, terms, and conditions, are lawful, just, and reasonable, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2017.

e. SCE&G's calculation and method of accounting for avoided and incremental costs for NEM during the review period of January 1, 2016, through December 31, 2016 ("Actual Period"), were reasonable and prudent, were consistent with methodology approved in Commission Order No. 2015-194, and complied with S.C. Code Ann. § 58-40-10, *et seq.* (2015).

f. During the Actual Period SCE&G offered DER programs and took steps to fulfill its DER goals approved in Commission Order No. 2015-194. The programs and steps were reasonable, prudent, complied with Commission Order Nos. 2015-194 and 2015-512, and were designed to meet SCE&G's statutorily designated goals as prescribed by S.C. Code Ann. § 58-39-130 (2015).

g. The cumulative balances of SCE&G's DER program costs as of December 31, 2016, totaled an over-collected balance of $1,709,006 in avoided costs and an under-collected balance of ($698,707) in incremental costs, which are reasonable and prudent.

h. SCE&G reasonably projected its DER program costs for the period January 1, 2017, through April 30, 2018, which are accurately reflected in Exhibit No. ___ (AWR-7) and Exhibit No. ___ (AW-R-9) attached to the direct testimony of Allen W. Rooks.

i. SCE&G's proposed DER Avoided Cost Component by class, as set forth below, are reasonable and prudent, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2017.

Class	DER Avoided Cost Component (¢/kWh)
Residential	0.015
Small General Service	0.013
Medium General Service	0.011
Large General Service	0.007

j. SCE&G's proposed monthly per account DER Incremental Cost Components by class, as set forth below, properly allocate SCE&G's DER program incremental costs, are reasonable and prudent, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2017.

Class	Monthly Per Account DER Incremental Cost Component
Residential	$ 0.91
Small & Medium Gen. Svc.	$ 3.29
Large General Service	$ 100.00

k. The tariff sheet entitled, "Adjustment for Fuel, Variable Environmental, & Avoided Capacity, and Distributed Energy Resource Program Costs," attached hereto as Attachment D, including the rates, terms, and conditions, is lawful, just, and reasonable, and, if approved by the Commission, shall become effective for the period beginning with the first billing cycle for May 2017.

<u>Fuel Expenses and Power Plant Operations</u>

B.3. ORS's review of SCE&G's operation of its generating facilities resulted in ORS concluding that SCE&G made reasonable efforts to maximize unit availability and minimize fuel costs. Additionally, ORS determined that SCE&G took appropriate corrective action with respect to outages that occurred during the Actual Period. Further, ORS concluded that, subject to any adjustments set forth in ORS's pre-filed direct testimony, SCE&G's accounting practices are in compliance with S.C. Code Ann. § 58-27-865 (2015).

B.4 The Settling Parties agree to accept all recommendations, if any, in ORS witnesses Smith's and Morgan's testimonies and exhibits pertaining to SCE&G's fuel expenses and power plant operations for the Actual Period, and January 1, 2017, through April 30, 2017 ("Estimated Period"), as well as forecasted expenses for the period May 1, 2017 through April 30, 2018 ("Forecasted Period"). Accordingly, SCE&G's net cumulative over-collected balance of total base fuel, variable environmental, and avoided capacity costs for the periods ending December 2016, and estimated through April 2017, are \$56,504,223 and \$31,505,037, respectively. As of December 2016, the net cumulative over-collected balance of \$56,504,223 consists of cumulative over-collected base fuel costs of \$52,599,284 and cumulative over-collected environmental and avoided capacity costs of \$3,904,939. As of April 2017, the estimated net cumulative over-collected balance of \$31,505,037 consists of cumulative over-collected base fuel costs of \$29,465,939 and cumulative over-collected environmental and avoided capacity costs of \$2,039,098.

Fuel Factors

B.5. The Settling Parties agree that the appropriate fuel factors for SCE&G to charge pursuant to this Settlement Agreement for the period beginning with the first billing cycle for May 2017 and extending through the last billing cycle for April 2018 are listed below and set forth in Attachment D.

Class	Base Fuel Cost Component (¢/kWh)	DER Avoided Cost Component (¢/kWh)	Environmental Fuel & Avoided Capacity Component (¢/kWh)	Total Fuel Costs Factor (¢/kWh)
Residential	2.451	0.015	0.047	2.513
Small General Service	2.451	0.013	0.039	2.503
Medium General Service	2.451	0.011	0.033	2.495
Large General Service	2.451	0.007	0.020	2.478
Lighting	2.451	0.000	0.000	2.451

B.6. The Settling Parties agree that the base fuel cost component set forth in Paragraph B.5 above is projected to create an under-collected cumulative balance of base fuel costs as of April 30, 2018, of approximately ($61,000,000).

B.7. The Settling Parties agree that the Company be allowed carrying costs for base fuel cost component under-collected balances, as they occur, and if approved, be based on the 3-year U.S. Government Treasury Note rate plus 65 basis points.

B.8. If approved by the Commission, the proposed rates would increase the average monthly bill for a residential customer on Rate 8 using 1,000 kWh from $147.53 to approximately $148.31, or by $0.78. The net effect on a Rate 8 Residential Bill using 1,000 kWh per month including the Company's Annual DSM Review (Docket No. 2017-35-E), if approved by the Commission, and its recently approved Pension Rider Adjustment (Docket No. 2017-56-E) would be $0.00 or 0.00%.

B.9. The Settling Parties agree the fuel factors set forth above are consistent with S.C. Code Ann. § 58-27-865 (2015). The Settling Parties further agree that, except as provided in Paragraph B.2 and B.10 herein, any and all challenges to SCE&G's historical fuel costs recovery for the period ending December 2016, are not subject to further review; however, the projected fuel costs for the period beginning January 1, 2017, and thereafter, shall be an open issue in future fuel costs proceedings held under the procedure and criteria established in S.C. Code Ann. § 58-27-865 (2015).

Other

B.10. With regards to plant outages not completed as of December 31, 2016, if any, and outages where final reports of SCE&G, contractors, governmental entities or others are not available, if any, the Settling Parties agree that ORS retains the right to review the reasonableness of the plant outage(s) and associated costs in the review period during which the outage is completed or when the report(s) on such outage(s) become available.

B.11. Upon written request, SCE&G will provide the following to the Settling Parties:

a. Copies of the monthly fuel recovery reports currently filed with the Commission and ORS; and,

b. Quarterly forecasts beginning with the quarter ending June 30, 2017, of the expected fuel factors to be set at SCE&G's next annual fuel proceeding and SCE&G's historical over (under)-collected balance to date. SCE&G agrees it will put forth reasonable efforts to forecast the expected fuel factors to be set at its next annual fuel proceeding; however, the Settling Parties agree that these quarterly forecasts will not be admitted into evidence in any future SCE&G proceeding.

B.12. The Settling Parties support the Company's effort to use Internal Revenue Code Section 174 deduction claims to reduce the variable environmental and avoided capacity cost component of the total fuel cost factor and agree to the implementation of the benefit from the deferred tax liability in the manner outlined by SCE&G witness Coffer is reasonable.

B.13. The Settling Parties agree that the Company's request to suspend the BCA program indefinitely due to high response from customers and in the manner the Company proposed is reasonable.

B.14 The Settling Parties agree that the Company's requests to modify the existing Community Solar program by expanding the solar panel subscription offering to all eligible customers and for certain revisions to the Community Solar tariff to align with the First Amendment of their Credit Rate Agreement with Clean Energy Collective approved in Docket No. 2016-290-E, Order No. 2017-151, are reasonable.

C. REMAINING SETTLEMENT TERMS AND CONDITIONS

C.1 The Settling Parties agree this Settlement Agreement is reasonable, in the public interest, and in accordance with law and regulatory policy. This Settlement Agreement in no way constitutes a waiver or acceptance of the position of any Settling Party concerning the requirements of S.C. Code Ann. § 58-27-865 (2015) in any future proceeding.

C.2. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B) (2015). S.C. Code Ann. § 58-4-10(B)(1) through (3) reads in part as follows:

> "…'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) Economic development and job attraction and retention in South Carolina; and
> (3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

C.3. The Settling Parties agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission as a fair, reasonable, and full resolution in the above-captioned proceeding. The Settling Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Settlement Agreement and the terms and conditions contained herein.

C.4. This written Settlement Agreement contains the complete agreement of the Settling Parties. There are no other terms and conditions to which the Settling Parties have agreed. This Settlement Agreement integrates all discussions among the Settling Parties into the terms of this written document. The Settling Parties agree that this Settlement Agreement will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will this Settlement Agreement or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If the Commission should decline to approve this Settlement Agreement in its entirety, then any Settling Party desiring to do so may withdraw from this Settlement Agreement without penalty.

C.5. This Settlement Agreement shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Settling Parties hereto. Therefore, each Settling Party acknowledges its consent and agreement to this Settlement Agreement by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Settling Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

[PARTY SIGNATURES TO FOLLOW ON SEPARATE PAGES]

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

Jeffrey M. Nelson, Esquire
Andrew M. Bateman, Esquire
South Carolina Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
Phone: (803) 737-0823
(803) 737-8440
Fax: (803) 737-0895
Email: jnelson@regstaff.sc.gov
abateman@regstaff.sc.gov

WE AGREE:

Representing and binding South Carolina Energy Users Committee

Scott Elliott, Esquire
Elliott and Elliott, P.A.
1508 Lady Street
Columbia, SC 29201
Phone: (803) 771-0555
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WE AGREE:

Representing and binding South Carolina Electric & Gas Company

K. Chad Burgess, Esquire
Matthew W. Gissendanner, Esquire
South Carolina Electric & Gas Company
Mail Code C222
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RATE PR-1 — **SMALL POWER PRODUCTION, COGENERATION**

AVAILABILITY

Available to Small Power Producers and Cogenerators that are a Qualifying Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54. This schedule is not available for Qualifying Facilities that have power production capacity greater than 100 KW.

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATE
(Seller Charges & Credits)

For Qualifying Facilities, Company will pay Seller a monthly credit equal to the Energy Credit and the Capacity Credit reduced by the Seller Charge.

I. Energy Credit:

Company shall pay Seller the following rates per KWH for energy delivered by the Seller to Company's system.

		Summer (June -September)	Winter (October-May)
1.	On-Peak	\$0.03590	\$0.03801
2.	Off-Peak	\$0.03079	\$0.03549

The South Carolina Power Excise Tax of \$.0005 per KWH is included in the energy credits above.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS FOR ENERGY CREDITS

A. On-Peak Hours:

Summer Months of June - September:

The on-peak Summer hours are defined to be 10:00 a.m.-10:00 p.m. Monday-Friday.

Winter Months of October – May:

1. November through April: The on-peak hours are defined as those hours between 6:00 a.m.-1:00 p.m. and 5:00 p.m.-10:00 p.m., Monday-Friday.
2. October and May: The on-peak hours are defined as those hours between 10:00 a.m.-10:00p.m., Monday-Friday.

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

II. Capacity Credit:

In addition to the energy credit, the Company shall pay the Seller \$0.02079 per kWh for energy delivered by the Seller to the Company's system during critical peak Summer hours. The Company shall pay the Seller \$0.00715 per kWh for energy delivered by the Seller to the Company's system during critical peak Winter hours.

DETERMINATION OF CRITICAL PEAK HOURS FOR CAPACITY CREDITS

A. Critical Peak Hours:

Summer Months of June - August:

The critical peak Summer hours are defined to be 2:00 p.m. - 6:00 p.m. Monday-Friday.

Winter Months of December - February:

The critical peak Winter hours are defined to be 6:00 a.m. - 9:00 a.m. Monday-Friday.

III. Seller Charge:

Seller shall pay the following Seller Charge each monthly billing period \$ 4.50

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from Qualifying Facility until such facility and Company have executed an Agreement for Purchase of Power from Small Power Production facility or Cogeneration Facility.

AVAILABILITY

Available to Small Power Producers and Cogenerators that are a Qualifying Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54 that have power production capacity greater than 100 kW and less than or equal to 80 MW, and entering into a power purchase agreement ("Seller") with South Carolina Electric & Gas Company. This schedule is not available for Qualifying Facilities that have power production capacity greater than 80 MW or equal to or less than 100 KW.

CHARACTER OF SERVICE

Energy supplied by the Qualifying Facility must be at 60 hertz and voltage, phase and power factor approved by the Company.

Energy supplied by the Qualifying Facility must be at a voltage level compatible with the voltage level of the Company's system at the point of delivery.

MONTHLY RATES

For a Qualifying Facility as described in the Availability section above, the Company will pay Seller an amount equal to the Energy Payment and the Capacity Payment reduced by the Seller Charge. The Company will pay this amount monthly.

I. Energy Payment:

Company shall pay the Seller the following rates per kWh for energy delivered by the Seller to Company's system:

A. For the period 2017 - 2021:

		For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
		Summer (Jun. - Sep.)	Non-Summer (Oct. - May)	Summer (Jun. - Sep.)	Non-Summer (Oct. - May)
1.	On-Peak	$ 0.03384	$ 0.03483	$ 0.03384	$ 0.03483
2.	Off-Peak	$ 0.02845	$ 0.03170	$ 0.02845	$ 0.03170

B. For the period 2022 - 2026:

		For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
		Summer (Jun. - Sep.)	Non-Summer (Oct. - May)	Summer (Jun. - Sep.)	Non-Summer (Oct. - May)
1.	On-Peak	$ 0.03648	$ 0.03200	$ 0.03648	$ 0.03200
2.	Off-Peak	$ 0.02679	$ 0.02726	$ 0.02679	$ 0.02726

C. For the period 2027 - 2031:

		For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
		Summer (Jun. - Sep.)	Non-Summer (Oct. - May)	Summer (Jun. - Sep.)	Non-Summer (Oct. - May)
1.	On-Peak	$ 0.04070	$ 0.03587	$ 0.04070	$ 0.03587
2.	Off-Peak	$ 0.03040	$ 0.02935	$ 0.03040	$ 0.02935

The South Carolina Power Excise Tax of $.0005 per kWh is included in the energy payments above.

Transmission Level is defined as voltages equal to or greater than 33 kV. Distribution Level is defined as voltages less than 33 kV.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS FOR ENERGY PAYMENTS

A. On-Peak Hours:

Summer Months of June - September:

The on-peak Summer hours are defined to be 10:00 a.m. - 10:00 p.m. Monday-Friday.

Non-Summer Months of October - May:

1. November through April: The on-peak hours are defined as those hours between 6:00 a.m. - 1:00 p.m. and 5:00 p.m. - 10:00 p.m., Monday-Friday.
2. October and May: The on-peak hours are defined as those hours between 10:00 a.m. - 10:00p.m., Monday - Friday.

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

II. Capacity Payment:

In addition to the energy payment, the Company shall pay the Seller the following capacity payment per kWh for energy delivered by the Seller to the Company's system during Critical Peak hours.

For Energy Supplied at Transmission Level		For Energy Supplied at Distribution Level	
Summer (Jun. - Aug.)	Winter (Dec. - Feb.)	Summer (Jun. - Aug.)	Winter (Dec. - Feb.)
$ 0.01965	$ 0.00675	$ 0.01965	$ 0.00675

Transmission Level is defined as voltages equal to or greater than 33 kV. Distribution Level is defined as voltages less than 33 kV.

DETERMINATION OF CRITICAL PEAK HOURS FOR CAPACITY PAYMENTS

A. Critical Peak Hours:

Summer Months of June - August:

The critical peak Summer hours are defined to be 2:00 p.m. - 6:00 p.m. Monday-Friday.

Winter Months of December - February:

The critical peak Winter hours are defined to be 6:00 a.m. - 9:00 a.m. Monday-Friday.

III. Seller Charge:

Seller shall pay the following Seller Charge each monthly billing period: $ 45.00

BILLING MONTH

A Billing Month is defined in this schedule as the time period between successive meter readings for the purpose of monthly billing. Readings are taken approximately once each month.

MONTHLY RATE DETERMINATION

The Seller will be liable to the Company each billing month for the Seller Charge regardless of the amount of energy delivered by the Seller to the Company.

The Company will be liable to the Seller each billing month for an amount determined as the total kWh delivered to the Company's system times the cost per kWh as specified herein.

PAYMENT TERMS

Payments due the Seller under this schedule shall be payable to the Seller within fifteen (15) days of the billing date.

Payment due the Company under this schedule is due and payable to the Company within fifteen (15) days of the billing date.

LIMITING PROVISIONS

Company shall not be liable for purchase of electricity from a Qualifying Facility until such facility and Company have executed a power purchase agreement.

RIDER TO RETAIL RATES

NET ENERGY METERING FOR RENEWABLE ENERGY FACILITIES ("NEM")
(Page 1 of 4)

AVAILABILITY

This rider is available in conjunction with the Company's Retail Electric Service Rates, for a Customer-Generator. The customer's generating system must be manufactured, installed and operated in accordance with governmental and industry standards and must fully conform with the Company's current interconnection standards as approved by the Public Service Commission of South Carolina.

This rider is available on a first come, first serve basis until the total nameplate generating capacity of net energy metering systems equals 2% of the previous five-year average of the Company's South Carolina retail electric peak demand.

CHARACTER OF SERVICE

The applicable character of service is specific to the rate schedule that the customer receives service under.

RATE PER MONTH

The applicable rate per month shall be from the appropriate rate schedule as referenced in the availability section above. The monthly bill shall be determined as follows:

For electric service under a time-of-use rate schedule:

1. The basic facilities charge shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

2. Any demand charges shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

3. If a customer-generator's energy consumption exceeds the electricity provided by the customer-generator during a monthly billing period, the customer-generator shall be billed in kWh for the net electricity supplied by the Utility.

   If a customer-generator's energy generation exceeds the electricity provided by the Utility during a monthly billing period, the customer-generator shall be credited for the excess kWh generated during that billing period.

   Energy charges (or credits) shall be based on the rates in the applicable rate schedules as described in the availability section above. For on-peak energy, the customer's monthly usage amount in kilowatt-hours shall be reduced by the total of (a) any on-peak excess energy delivered to the Company in the current month plus (b) any accumulated on-peak excess energy balance remaining from prior months. Total on-peak energy in kilowatt-hours billed to customers shall never be less than zero. For off-peak energy, the customer's monthly usage shall be reduced by the total of (a) any off-peak excess energy delivered to the Company in the current month plus (b) any accumulated off-peak excess energy balance remaining from prior months plus (c) any accumulated on-peak excess energy balance from the current month or prior months that was not used to reduce on-peak usage. Total off-peak energy in kilowatt-hours billed to customers shall also never be less than zero. For any billing month during which excess energy exceeds the customer's usage in total, producing a net credit, the respective energy charges for the billing month shall be zero. Any excess energy credits shall carry forward on the following month's bill by first applying excess on-peak kWh against on-peak kWh charges and excess off-peak kWh against off-peak kWh charges, then applying any remaining on-peak kWh against any remaining off-peak kWh charges. Credits shall not offset the basic facilities charge or the demand charge for the applicable rate schedule.

4. Excess energy not used in the current billing month to reduce billed kWh usage shall be accumulated and used to reduce usage in future months. For all affected billing statements rendered during November billing cycles, any accumulated excess energy not used to reduce billed kWh usage shall be paid to the customer-generator at the Company's avoided cost, zeroing out the customer generator's account of excess energy. The avoided cost is the off-peak winter energy credit as approved in the Company's Rate PR-1, Small Power Production and Cogeneration schedule.

For electric service under a standard, non time-of-use rate schedule:

1. The basic facilities charge shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

2. Any demand charges shall be determined and billed as set forth in the applicable rate schedule as described in the Availability section above.

3. If a customer-generator's energy consumption exceeds the electricity provided by the customer-generator during a monthly billing period, the customer-generator shall be billed in kWh for the net electricity supplied by the Utility.

   If a customer-generator's energy generation exceeds the electricity provided by the Utility during a monthly billing period, the customer-generator shall be credited for the excess kWh generated during that billing period.

   Energy charges (or credits) shall be based on the rates in the applicable rate schedules as described in the availability section above. For purposes of calculating monthly energy, the customer's usage shall be reduced by the total of (a) any excess energy delivered to the Company in the current month plus (b) any accumulated excess energy balance remaining from prior months. Total energy in kilowatt-hours billed to customers shall never be less than zero. For any billing month during which excess energy exceeds the customer's usage in total, producing a net credit, the respective energy charges for the billing month shall be zero. Credits shall not offset the basic facilities charge or the demand charge for the applicable rate schedule.

4. Excess energy not used in the current billing month to reduce billed kWh usage shall be accumulated and used to reduce usage in future months. For all affected billing statements rendered during November billing cycles, any accumulated excess energy not used to reduce billed kWh usage shall be paid to the customer-generator at the Company's avoided cost, zeroing out the customer generator's account of excess energy. The avoided cost is the off-peak winter energy credit as approved in the Company's Rate PR-1, Small Power Production and Cogeneration schedule.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge plus the demand charge, if any, as stated in the applicable rate.

DEFINITIONS

1. Customer-Generator means the owner, operator, lessee, or customer-generator lessee of an electric energy generation unit which:

   (A) generates electricity from a Renewable Energy Resource;
   (B) has an electrical generating system with a capacity of:
      (i) not more than the lesser of one thousand kilowatts (1,000 kW AC) or one hundred percent (100%) of contract demand if a non-residential customer; or
      (ii) not more than twenty kilowatts (20 kW AC) if a residential customer;
   (C) is located on a single premises owned, operated, leased, or otherwise controlled by the customer;
   (D) is interconnected and operates in parallel phase and synchronization with an electrical utility and complies with the applicable interconnection standards;
   (E) is intended primarily to offset part or all of the customer-generator's own electrical energy requirements; and
   (F) meets all applicable safety, performance, interconnection, and reliability standards established by the commission, the National Electrical Code, the National Electrical Safety Code, the Institute of Electrical and Electronics Engineers, Underwriters Laboratories, the federal Energy Regulatory Commission, and any local governing authorities.

2. Renewable Energy Resource means solar photovoltaic and solar thermal resources, wind resources, hydroelectric resources, geothermal resources, tidal and wave energy resources, recycling resources, hydrogen fuel derived from renewable resources, combined heat and power derived from renewable resources, and biomass resources.

3. Retail Electric Service Rates shall mean Rates 1, 2, 3, 5, 6, 7, 8, 9 (metered), 11, 12, 13, 14, 16, 20, 21, 21A, 22, 23, 24, and 28.

4. Excess energy delivered to the Company shall be defined as energy produced by the customer's renewable energy generating facility that exceeds the energy delivered by the Company during a given time period. This excess energy shall be used to reduce energy delivered and billed by the Company during the current or a future month, as provided in the Rate Per Month section above.

5. The On-Peak and Off-Peak periods shall be defined in the applicable time-of-use rate schedules.

GENERAL PROVISIONS

1. To qualify for this rider, the customer must first qualify for and be served on one of the rate schedules as described in the availability section above. The customer must also meet all other qualifications as outlined in the availability section above.

2. All provisions of the applicable rate schedules described above including, but not limited to Billing Demand, Determination of On- and Off-Peak Hours, Adjustment for Fuel Costs, Demand Side Management Component, Pension Costs Component, Storm Damage Component, Sales and Franchise Tax, Payment Terms, and Special Provisions will apply to service supplied under this rider.

3. Customers electing service under this NEM Rider are eligible to remain on the Rider until December 31, 2025, or until such time as the customer elects to terminate service under the Rider, whichever occurs first. The rates set forth here are subject to Commission Order No. 2015-194 in Docket No. 2014-246-E entered under the terms of S.C. Code § 58-40-20(F)(4). Eligibility for this rate will terminate as set forth in Order No. 2015-194. The value of distributed energy resource generation shall be computed using the methodology contained in Commission Order No. 2015-194 in Docket No. 2014-246-E and updated annually coincident in time with the Company's filing in the fuel clause. The value for the period May 2017 – April 2018 is $0.03651 per kWh.

4. Service on this NEM Rider will be closed to new participants as of January 1, 2021, or after statutory caps described in S.C. Code Ann. § 58-39-130 have been reached, whichever occurs first.

5. When no contract demand level is available for a non-residential customer, connected load as determined by the Company shall be used as a proxy for contract demand when determining the capacity of the electrical generating system.

6. Customers who elect NEM service after January 1, 2021, will receive service in accordance with the NEM tariff in effect at the time at which the customer requests NEM service.

7. Customers served under this rider are not eligible for the Company's Small Power Production, Cogeneration Rate PR-1.

8. The customer must execute an application to interconnect generation and an interconnection agreement prior to receiving service under this rider.

9. The Company will retain ownership of Renewable Energy Credits ("RECs").

10. In the event the Company determines that it is necessary to increase the capacity of facilities beyond those required to serve the Customer's electrical requirement or to install a dedicated transformer or other equipment to protect the safety and adequacy of electric service provided to other customers, the Customer shall pay the estimated cost of the required transformer or other equipment above the estimated cost which Company would otherwise have normally incurred to serve the Customer's electrical requirement, in advance of receiving service under this Rider.

RIDER TO RETAIL RATES

NET ENERGY METERING FOR RENEWABLE ENERGY FACILITIES ("NEM")
(Page 4 of 4)

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

METERING REQUIREMENTS

Customer must furnish, install, own, and maintain a meter socket to measure 100% of the Customer's generator output and that is connected on the Customer's side of the delivery point. Company will furnish, install, own, and maintain a generation meter. Company will also furnish, install, own and maintain a bi-directional billing meter to measure the kWh delivered from Company to Customer and to measure kWh received from Customer by Company. The billing meter will be configured for demand and/or time-of-use measurement as required by the applicable rate. All metering shall be at a location that is approved by the Company. At Company's sole option, the generator meter requirement may be waived for customers served under a net metering rider on or before December 31, 2015.

TERM OF CONTRACT

Contracts shall be for a period not to exceed the term of the contract under which the customer currently receives electric service. There shall be a separate contract for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are part of this rider.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

APPLICABILITY

This adjustment is applicable to and is part of the Utility's South Carolina retail electric rate schedules.

The fuel, variable environmental & avoided capacity, and DER avoided costs, to be recovered in an amount rounded to the nearest one-thousandth of a cent per kilowatt-hour, will be determined by the following formulas:

$$F_C = \frac{E_F}{S} + \frac{G_F}{S_1}$$

$$F_{EC} = \frac{E_{EC} + G_{EC}}{S_2}$$

$$F_{AC} = \frac{E_{AC} + G_{AC}}{S_2}$$

Total Fuel Rate
per kWh $= F_C + F_{EC} + F_{AC}$

Where:

F_C = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one-thousandth of a cent.

E_F = Total projected system fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

PLUS

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel costs associated with energy purchased are identifiable and are identified in the billing statement, and also including avoided energy costs incurred by the Utility. Also, the cost of "firm generation capacity purchases," which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. Costs of "firm generation capacity purchases" includes the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

PLUS

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing Utility's avoided variable costs for the generation of an equivalent quantity of electric power.

Energy receipts that do not involve money payments such as diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

MINUS

(D) The cost of fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G_F = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E_F and S.

S_1 = Projected jurisdictional kilowatt-hour sales, for the period covered by the fuel costs included in E_F.

F_{EC} = Customer class variable environmental and avoided capacity costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

E_{EC} = The projected variable environmental costs including: a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, plus b) the cost of emission allowances, as used, including allowances for SO2, NOx, mercury and particulates minus net proceeds of sales of emission allowances, and c) as approved by the Commission, all other variable environmental costs incurred in relation to the consumption of fuel and air emissions caused thereby, including but not limited to environmental reagents, other environmental allowances, and emission related taxes. Any environmental related costs recovered through intersystem sales would be subtracted from the totals produced by subparts a), b), and c). This component also includes avoided capacity costs incurred by the Utility.

These environmental and avoided capacity costs will be allocated to retail customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{EC} = Cumulative difference between jurisdictional customer class environmental fuel revenues billed and jurisdictional customer class environmental costs at the end of the month preceding the projected period utilized in E_{EC} and S_2.

F_{AC} = Customer class DER avoided costs per kilowatt-hour included in base rates, rounded to the nearest one-thousandth of a cent.

E_{AC} = The projected DER avoided costs paid to distributed generators as most recently determined by the Public Service Commission of South Carolina. These avoided costs will be allocated to retail electric customer classes based upon the customer class firm peak demand allocation from the prior year.

G_{AC} = Cumulative difference between jurisdictional customer class avoided cost revenues billed and jurisdictional customer class avoided costs at the end of the month preceding the projected period utilized in E_{AC} and S_2.

S_2 = The projected jurisdictional customer class kilowatt-hour sales.

The appropriate revenue-related tax factor is to be included in these calculations.

FUEL RATES PER KWH BY CLASS

The total fuel costs in cents per kilowatt-hour by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2017 through April, 2018:

Customer Class	F_C Rate	+	F_{EC} Rate	+	F_{AC} Rate	=	Total Fuel Rate
Residential	**2.451**		**0.047**		**0.015**		**2.513**
Small General Service	**2.451**		**0.039**		**0.013**		**2.503**
Medium General Service	**2.451**		**0.033**		**0.011**		**2.495**
Large General Service	**2.451**		**0.020**		**0.007**		**2.478**
Lighting	**2.451**		**0.000**		**0.000**		**2.451**

The incremental costs associated with SCE&G's Distributed Energy Resource Programs, to be recovered in an amount rounded to the nearest cent per account, will be determined by the following formulas:

Total Fuel Rate per Account

$$F_{IC} = \frac{E_{DC} + G_{DC}}{C}$$

Where:

F_{IC} = Fuel cost per account included in base rate, rounded to the nearest cent, not to exceed $12 for residential customers, $120 for small/medium general service customers, and $1,200 for large general service customers.

E_{DC} = The projected incremental costs associated with SCE&G's Distributed Energy Resource Program as determined by the Public Service Commission of South Carolina

G_{DC} = Cumulative difference between jurisdictional customer class distributed energy component revenues billed and jurisdictional customer class incremental costs associated with SCE&G's Distribued Energy Resource Program at the end of the month preceding the projected period utilized in E_{DC} and C.

C = The jurisdictional customer class account totals.

FUEL RATES PER ACCOUNT PER MONTH BY CLASS

The total fuel costs in dollars per account by customer class as determined by the Public Service Commission of South Carolina in Order No. ____-___ are as follows for the period May, 2017 through April, 2018:

Customer Class		F_{IC} Rate
Residential	**$**	**0.91**
Small & Medium General Service	**$**	**3.29**
Large General Service	**$**	**100.00**

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2017-221-E

IN RE:

Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of the Graniteville-South Augusta 230 kV Tie Line and Urquhart-Graniteville #2 230 kV Line and Associated Facilities	)	**STIPULATION**

This Stipulation is made by and between the South Carolina Office of Regulatory Staff ("ORS") and South Carolina Electric & Gas Company ("SCE&G") (collectively referred to as the "Parties" or sometimes individually as a "Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina ("Commission") pursuant to the provisions in S.C. Code Ann. § 58-33-10 *et seq*. (2015) ("the Siting Act") and 10 S.C. Code Ann. Regs. 103-304 (2012) at the request of SCE&G, which filed an Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of the Graniteville-South Augusta 230 kV Tie Line and Urquhart-Graniteville #2 230 kV Line and Associated Facilities ("Application");

WHEREAS, in the Application, as modified in SCE&G's direct testimony, SCE&G seeks a Certificate of Environmental Compatibility and Public Convenience and Necessity ("Certificate") for the construction and operation of two 230 kilovolt ("kV") transmission lines.

The first is a new single circuit 230 kV tie line connecting the SCE&G and Southern Company electrical transmission systems originating at the Southern Company's South Augusta Substation and running to SCE&G's existing Graniteville No. 2 Substation. The second line will originate at SCE&G's existing Urquhart 230 kV Substation adjacent to the Urquhart Generating Station and run to SCE&G's existing Graniteville No. 1 Substation. SCE&G states that these facilities are needed to prevent excessive electrical loading on a critical Southern Company-SCE&G interconnecting 230 kV Line;

WHEREAS, the Parties to this Stipulation are parties of record in the above-captioned docket;

WHEREAS, in accordance with the provisions of S.C. Code Ann. § 58-33-140 (2015) the South Carolina Department of Health and Environmental Control ("DHEC"), the South Carolina Department of Natural Resources, and the South Carolina Department of Parks, Recreation, and Tourism, are also parties to this proceeding (collectively, the "Other Parties of Record"). The Other Parties of Record have all made filings with the Commission indicating that they have no issues or concerns with SCE&G's Application. DHEC has, however, specifically provided that its consent here does not waive any comments or concerns which it may have in future proceedings before the Commission or in reviewing any relevant applications for DHEC permits or approvals on this project;

WHEREAS, the Parties have engaged in discussions to determine if a Stipulation would be in their best interest; and

WHEREAS, following these discussions the Parties have determined that their interests, and those of the public, would be best served by reaching an agreement on matters set forth in SCE&G's Application in the above-captioned case under the terms and conditions set forth below:

1. The Parties agree to stipulate into the record before the Commission the direct testimony and exhibits of the following witnesses without objection, change, amendment or cross-examination with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction.

A. SCE&G witnesses: Joseph Wade Richards and Nathan V. Bass.
B. ORS witness: Michael L. Seaman-Huynh.

2. As a compromise, the following is adopted, accepted, and acknowledged as the agreement of the Parties:

A. ORS will recommend that the Commission approve SCE&G's Application, as modified in SCE&G's direct testimony, and grant SCE&G a Certificate for the Graniteville #2-South Augusta 230 kV Tie Line and Urquhart-Graniteville 230 kV Line and Associated Facilities, as requested in the Application in this Docket;

B. SCE&G agrees to follow all South Carolina, Commission and local government regulations and laws arising from matters set forth in the Application; and

C. SCE&G will notify ORS and the Commission when the facilities begin commercial operation and of any changes to the planned commercial operation dates.

3. The Parties agree this Stipulation is reasonable, in the public interest and in accordance with law and regulatory policy.

4. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B) (2015). S.C. Code Ann. § 58-4-10(B)(1) through (3) reads in part as follows:

> "...'public interest' means a balancing of the following:
>
> (1) Concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;

(2) Economic development and job attraction and retention in South Carolina; and

(3) Preservation of the financial integrity of the State's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services."

5. The Parties agree to cooperate in good faith with one another in recommending to the Commission that this Stipulation be accepted and approved by the Commission as a fair, reasonable and full resolution in the above-captioned proceeding. The Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Stipulation and the terms and conditions contained herein.

6. This written Stipulation contains the complete agreement of the Parties. There are no other terms and conditions to which the Parties have agreed. The Parties agree that this Stipulation will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will the Stipulation or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If the Commission should decline to approve the Stipulation in its entirety, then any Party desiring to do so may withdraw from the Stipulation without penalty.

7. This Stipulation shall be interpreted according to South Carolina law. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Stipulation by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Stipulation.

WE AGREE:

Representing and binding the South Carolina Office of Regulatory Staff

Jeffrey M. Nelson, Esquire
South Carolina Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, South Carolina 29201
Phone: 803.737.0823
Fax: 803.737.0895
Email: jnelson@regstaff.sc.gov

Date: September 14, 2017

WE AGREE:

Representing and binding South Carolina Electric & Gas Company

Matthew W. Gissendanner

K. Chad Burgess, Esquire
Matthew W. Gissendanner, Esquire
South Carolina Electric & Gas Company
220 Operation Way MC C222
Cayce, South Carolina 29033
Phone: 803.217.8141
Fax: 803.217.7931
Email: chad.burgess@scana.com
matthew.gissendanner@scana.com

Date: September 14, 2017

STATE OF SOUTH CAROLINA)
) **RELEASE**
COUNTY OF BEAUFORT)

KNOW ALL MEN BY THESE PRESENTS, that I, **Christopher Shane Blevins**, for and in consideration of the sum of Eight Hundred Thousand and 00/100 ($800,000.00) Dollars, receipt of which is hereby acknowledged, do hereby release and forever discharge, SCANA, The South Carolina Electric and Gas Company ("SCE&G"), their agents, servants, employees, successors and assigns, and any and all other persons, firms or corporations from any and all actions, causes of action, demands and/or claims of any nature whatsoever which I may have against them for injuries and damages resulting from an accident that occurred on or about August 13, 2013, when Christopher Shane Blevins was injured in an incident involving a junction box on Bray's Island near Beaufort South Carolina. The consideration expressed herein constitutes payment in full to me for all damages, losses and/or injuries to persons or property or both, whether known or unknown, developed or undeveloped, which have resulted or may result from the incident aforesaid, including all claims which were or could have been asserted in the lawsuit filed in the Beaufort Court of Common Pleas captioned <u>Christopher Shane Blevins vs. The South Carolina Electric and Gas Company and Thomas & Betts Corporation</u>, civil action no. 2016-CP-07-01707.

I hereby declare and represent that the injuries sustained may be permanent and/or progressive and that recovery therefrom is uncertain and indefinite, and that in making this Release, it is understood and agreed that I rely wholly on my own judgment, belief, and knowledge of the nature and extent and consequences of said injuries and no representation or statement regarding the said injuries or regarding any other matter made by any of the persons, firms, or corporations who are hereby released, or by any person or persons representing them or employed by them have influenced me to any extent in making this Release.

I further agree and expressly warrant that I shall be solely responsible for the payment of any and all medical expenses, and any other expenses incurred by me as a result of the accident. I expressly agree that I shall be solely responsible for the payment of any claims, which might be asserted by any insurance carrier, or other entity which made the payments on medical bills or expenses for or on behalf of Christopher Shane Blevins and which assert any lien against the proceed of this settlement. The undersigned expressly agrees that this is his responsibility and he expressly agrees to hold harmless and indemnify the entities to whom he gives this release listed above for the payment of such sums.

It is further understood and agreed that the payment of the above amount is not to be construed as an admission of liability on the part of the person or persons being released, liability by them being expressly denied.

All agreements and understandings between the parties hereto are embodied and expressed herein and the terms of this Release are contractual and not a mere recital.

I have read the foregoing Release and understand it to be a full, final and binding agreement.

IN WITNESS WHEREOF, I have hereunto set my hand and seals this 25 day of October, 2017.

WITNESSES:

Sherri Garrett

Jan Parker

(SEAL)

Christopher Shane Blevins

FULL AND COMPLETE RELEASE

KNOW ALL MEN BY THESE PRESENTS, that I, Matthew M. Breen, for and in consideration of the payment of the sum of Two Hundred Dollars ($200.00) from SCANA Services, Inc. the receipt and sufficiency of which is hereby acknowledged, for me and my heirs, beneficiaries, representatives, personal representatives, successors and assigns, do hereby release, acquit and forever discharge SCANA Services, Inc. as well as South Carolina Electric and Gas Company and all other SCANA Corporation subsidiaries and their respective heirs, beneficiaries, representatives, personal representatives, successors, assigns, insurers, attorneys, and all other persons, firms, or companies who can or may be liable, of and from any and all actions, causes of action, claims, demands, damages, costs, expenses and compensation, on account of, or in any way growing out of, any and all known and unknown injuries and damages of whatsoever nature, whether past, present or future, and the results of such injuries and damages, arising from or related to what was alleged, or could have been alleged, in the civil action captioned: *Matthew M. Breen. v. South Carolina Electric and Gas Company and SCANA Services, Inc*, Case No: 2015CV1010600989, pending in the Charleston County Small Claims Court ("the Lawsuit").

I hereby acknowledge full satisfaction and settlement of all such claims and causes of action and fully understand that neither I nor my heirs, beneficiaries, representatives, personal representatives, successors, or assigns can make any further claim against the persons, firms or companies who are hereby released. It is further understood that this release shall not be subject to any claim of mistake of fact, and regardless of the adequacy or inadequacy of the amount paid, it is intended to be final and complete.

I further represent and warrant that I have not heretofore assigned to any other person or entity all or any portion of any claim whatsoever which I may have or may have had or may claim in the future to have against the persons, firms or companies hereby released, and represent and warrant that I am the sole proper party to receive the proceeds of the settlement of the aforementioned lawsuit.

It is further understood and agreed that this settlement is a compromise of doubtful and disputed claims, and that the payment of sums herein mentioned is not to be construed as an admission of liability on the part of the persons, firms and companies who are hereby released, by whom liability is expressly denied.

It is further agreed that I, as well as my heirs, beneficiaries, representatives, personal representatives, successors and assigns, will forever hold harmless, indemnify and defend SCANA Services, Inc. as well as South Carolina Electric and Gas Company and all other SCANA Corporation subsidiaries and their respective heirs their respective heirs, beneficiaries, representatives, personal representatives, successors, assigns, insurers, and attorneys, against loss from any further claims, demands, or actions that may hereafter be initiated by any governmental agency or entity, company, or person pursuant to any lien, assignment, letter of protection or right of subrogation in connection with medical bills or other expenses or benefits paid on my behalf in connection with the above-referenced accident.

I hereby declare and represent that I am of legal age, that in making this release I relied wholly upon my own judgment, belief and knowledge of the nature, extent and duration of said injuries and damages, and that I have not been influenced to any extent whatever in making this release by any representations or statements regarding said injuries or damages, or regarding any other matters, made by the persons, firms or companies who are hereby released, or by any person or persons representing them or any of them.

It is further understood and agreed that there is no promise or agreement on the part of the persons, firms and companies who are hereby released to do or omit to do any act or thing not herein mentioned, that this release contains the entire agreement between the parties hereto, and that the terms of this release are contractual and not a mere recital. This Release shall be interpreted and enforced according to the laws of the State of South Carolina.

I further state that I have either read the foregoing release or have had it read to me, understand the contents thereof, and sign the same as my own free act.

WITNESS my hand and seal this 29 day of January, 20/6.

Matthew M. Breen

STATE OF SOUTH CAROLINA)
COUNTY OF CHARLESTON)

On this 29 day of January, 20/6, before me personally appeared Gail Wright to me known to be the person described in and who executed the foregoing release, and acknowledged that they executed the same as their free act and deed.

Notary Public for South Carolina
My commission expires: 1-2[illegible]-2025

CONFIDENTIAL FULL AND FINAL SETTLEMENT AGREEMENT AND RELEASE OF ALL CLAIMS

This Confidential Full and Final Settlement Agreement and Release of all Claims ("this Agreement") is made and entered into by Ms. Hedwig Wilson and South Carolina Electric and Gas Company ("SCE&G"), its present or former parent, subsidiaries, affiliates, agents, servants, employees, representatives, attorneys and insurers, both singularly and collectively, and any other persons or entities in privity with same, whether named or not.

This Agreement is a result of alleged damages incurred on or about February 2016 as a result of right-of-way maintenance by SCE&G at Ms. Wilson's residence at 6130 Gill Greek Road in Columbia, South Carolina, as more fully alleged in the Complaint filed with the Public Service Commission of South Carolina on or about May 31, 2016, by Mr. Robert Wilson, as Representative for Hedwig Wilson, in Docket No. 2016-226-E ("Incident").

Now, therefore, I, Hedwig Wilson, covenant and agree as follows:

I have the right to consult with an attorney before signing this Agreement.

As consideration for the promises, releases and covenants, the dismissal of my claim against SCE&G and other good and valuable consideration, SCE&G agrees to pay the sum of two thousand seven hundred dollars ($2,700) to Ms. Hedwig Wilson contemporaneously with the execution of this Agreement. I acknowledge that there is a risk that, subsequent to the execution of this Agreement, I may discover, incur or suffer from claims, damages or injuries that are unknown or unanticipated at the time this Agreement is executed, including without limitation, unknown or unanticipated claims, damages or injuries that allegedly arise from, are based upon or are related to the Incident, which, if known by me on the date this Agreement was executed, may have materially affected my decision to execute this Agreement. I acknowledge that I am assuming the risk of such unknown or unanticipated claims, damages or injuries and agree that this Agreement applies thereto. The provisions of any local, state or federal law, statute or judicial decision providing in substance that releases shall not extend to such unknown or anticipated claims, damages or injuries are hereby expressly waived. For the sole consideration of $2,700.00, I release and forever discharge SCE&G, its present or former parent, subsidiaries, affiliates, agents, servants, employees, representatives, attorneys and insurers, both singularly and collectively, and any other persons or entities in privity with same, whether named or not from any and all claims, demands, damages, actions, causes of action or suits of any kind or nature whatsoever, and particularly on account of all injuries, known and unknown, both to person and property, which have resulted or may in the future develop from the Incident.

I agree that the terms of this Agreement, including, but not limited to, the terms of the settlement agreed to herein, shall be kept strictly confidential and that I will not disclose to anyone either the fact that this Agreement has been entered into or its terms, other than as may be required by law, or as may be mutually consented to in writing.

IT IS SO AGREED.

Mrs. Hedwig S. Wilson

Ms. Hedwig Wilson

STATE OF SOUTH CAROLINA)
)
COUNTY OF RICHLAND)

PERSONALLY APPEARED BEFORE ME Adger Rice, who made oath that (s)he saw Hedwig Wilson sign the foregoing Agreement and that (s)he with ________, witnessed the execution thereof.

Mrs Hedwig S. Wilson

SWORN to before me this 18 day of July, 2016.

Notary Public for South Carolina
My Commission Expires: 12-08-2025

AARON ADGER RICE III
COM. EXP.
NOTARY
PUBLIC
12-08-2025
SOUTH CAROLINA

August 2, 2017

The Public Service Commission
State of South Carolina
101 Executive Center Dr., Ste. 100
Columbia, SC 29210-8411

Re: Docket No. 2017-198-E- Dennis Gallipeau, Complainant/Petitioner
v. South Carolina Electric & Gas Company, Defendant/Respondent

NOTICE OF WITHDRAWAL OF COMPLAINT

Dear Commission:

The Office of Regulatory Staff has facilitated settlement of the above captioned matter, memorialized in its July 27, 2017 letter to your Complainant.

Accordingly, the Complaint is hereby withdrawn and this matter may be closed.

Sincerely,

Dennis M.Gallipeau, pro se
1920 Ashford Lane
Columbia, SC 29210
764-1718

cc: Matthew W. Gissendanner, Esq. (for SCE&G)
Shannon B. Hudson, Esq. (for ORS)

via email to Brad Kirby (ORS)

Kelley N. Brown
Legal Department • MC – C222
kelley.brown@scana.com

February 19, 2014

Christopher S. Leonard, Esquire
Kendrick & Leonard, P.C.
Post Office Box 886
Columbia, SC 29201

Re: Marthe Williams v. South Carolina Electric and Gas Company
Case No. 2013-CP-32-01215

Dear Mr. Leonard:

Enclosed is a copy of the filed Stipulation of Dismissal for your records.

Thank you for your cooperation. If you need additional information or have any questions, please do not hesitate to contact me.

Sincerely,

Kelley Brown

Kelley N. Brown
Sr. Paralegal to John M. Mahon, Jr.

Enclosure

Cc: Frank Bouknight

STATE OF SOUTH CAROLINA	)	
	)	**RELEASE**
COUNTY OF LEXINGTON	)	

KNOW ALL MEN BY THESE PRESENTS, that I, Marthe Williams, for and in consideration of the sum of Twenty Three Thousand Seven Hundred Fifty Dollars and 00/100 ($23,750.00), receipt of which is hereby acknowledged, do hereby forever discharge and release South Carolina Electric and Gas Company (hereinafter SCE&G), and any and all other persons, firms, and corporations, their agents, employees, servants, heirs and successors, from any and all actions, causes of action, demands and/or claims of whatsoever nature which we may have in any way growing out of an incident which occurred on or about April 6, 2010, when Marthe Williams' back yard at 1532 Northland Drive in Cayce, South Carolina caught fire; to include any claims or causes of action that were or could have been asserted by Marthe Williams in that specific lawsuit Marthe Williams v. SCE&G, filed by Marthe Williams on or about April 5, 2013 in Lexington County Court of Common Pleas bearing docket number 2013-CP-32-01215; the consideration expressed herein constitutes a payment in full for all damages, losses and/or injuries to persons or property or both, whether known or unknown, developed or undeveloped, which have resulted or may result from the incident aforesaid.

We hereby declare and represent that the damages and/or injuries sustained may be permanent and/or progressive and that recovery therefrom is uncertain and indefinite, and that in making this Release, it is understood that we rely wholly on our own judgment, belief, and knowledge of the nature, extent and consequences of the damages and/or injuries and no representation or statement regarding any of the damages and/or injuries or regarding any other matter made by any of the persons, firms or corporations who are hereby released, or by any person or persons representing them or employed by them have influenced us to any extent whatsoever in making this Release.

It is further understood and agreed that the payment of the above amounts is not to be construed as an admission of liability on the part of the person or persons being released, liability by them being expressly denied.

We further understand and agree that any subrogated or third party interests, such as medical charges or Homeowners Insurance which were incurred as a result of the incident, must be satisfied in full from the proceeds of this settlement and we agree to hold harmless and indemnify SCE&G from any and all liability or responsibility with regard to such third party interests or liens, including any cost to enforce this provision or defend any actions brought by the third parties.

All agreements and understandings between the parties hereto are embodied herein and the terms of this Release are contractual and not a mere recital.

We have read the foregoing Release and understand it to be a full, final, and binding agreement.

IN WITNESS WHEREOF, we have hereunto set our hands and seals this 23 day of Jan., 2014.

WITNESSES:

____________________ ____________________

____________________ Marthe Williams

STATE OF SOUTH CAROLINA)
)
COUNTY OF Richland)

PERSONALLY appeared before me, Tivis Sutherland, who made oath
(Witness No. 1)

that (s)he saw the within named Marthe Williams sign the foregoing Release, and that (s)he, with Mark Whitlock witnessed the execution thereof. (Witness No. 2)

(Witness No. 1)

Sworn to and subscribed before
me this 23rd day of Jan, 2014.

(L.S.)

Notary Public for South Carolina
My Commission Expires: 1-13-2021

As attorney for the Plaintiff and a member of the South Carolina Bar, I do hereby approve the foregoing settlement and the execution of the Release set out hereinabove.

Christopher S. Leonard, Esquire
Kendrick & Leonard, P.C.

Columbia ~~1/23/2014~~, South Carolina
1/23, 2014

STATE OF SOUTH CAROLINA) COURT OF COMMON PLEAS
COUNTY OF LEXINGTON) ELEVENTH JUDICIAL CIRCUIT

CASE NO.: 2013-CP-32-01215

Marthe Williams

STIPULATION OF DISMISSAL

Plaintiff,

v.

South Carolina Electric and Gas Company

Defendant.

COPY

The above entitled action has been ended between the parties by way of compromise. Now, therefore, pursuant to Rule 41(a) SCRCP and by agreement of all parties appearing, it is hereby stipulated that the Complaint of the Plaintiff be and the same is hereby dismissed with prejudice.

AND IT IS SO STIPULATED.

January 23, 2014

Christopher S. Leonard
Kendrick & Leonard, P.C.
Attorney for Plaintiff

John M. Mahon, Jr.
Attorney for Defendant

John M. Mahon, Jr.
Associate General Counsel
Legal Department • MC – C222
jmahon@scana.com

January 17, 2014

Christopher S. Leonard, Esquire
Kendrick & Leonard, P.C.
Post Office Box 886
Columbia, SC 29201

Re: Marthe Williams v. South Carolina Electric and Gas Company
Case No. 2013-CP-32-01215

Dear ~~Mr. Leonard:~~ Chris

Enclosed herewith for your execution is the original Release and an original Stipulation of Dismissal executed by me. Please execute the Release and the Stipulation of Dismissal and return to me in the self addressed stamped envelope. I will forward the fully executed Stipulation of Dismissal to Lexington County Clerk of Court to be filed.

Also, enclosed is a check for twenty three thousand seven hundred and fifty dollars and 00/100 ($23,750.00). Please hold the check in trust until the Release is fully executed and the Stipulation of Dismissal is filed. I will forward you a copy of the filed Stipulation of Dismissal as soon as possible.

Thank you for your cooperation. If you need additional information or have any questions, please do not hesitate to contact me.

Sincerely,

John M. Mahon, Jr.

Enclosures

STATE OF SOUTH CAROLINA COUNTY OF LEXINGTON	)	COURT OF COMMON PLEAS ELEVENTH JUDICIAL CIRCUIT
	)	CASE NO.: 2013-CP-32-01215
Marthe Williams	)	STIPULATION OF DISMISSAL
Plaintiff,	)	
v.	)	
South Carolina Electric and Gas Company	)	
Defendant.	)	

The above entitled action has been ended between the parties by way of compromise. Now, therefore, pursuant to Rule 41(a) SCRCP and by agreement of all parties appearing, it is hereby stipulated that the Complaint of the Plaintiff be and the same is hereby dismissed with prejudice.

AND IT IS SO STIPULATED.

January ________, 2014

____
Christopher S. Leonard
Kendrick & Leonard, P.C.
Attorney for Plaintiff

____
John M. Mahon, Jr.
Attorney for Defendant

STATE OF SOUTH CAROLINA)
) **RELEASE**
COUNTY OF LEXINGTON)

KNOW ALL MEN BY THESE PRESENTS, that I, Marthe Williams, for and in consideration of the sum of Twenty Three Thousand Seven Hundred Fifty Dollars and 00/100 ($23,750.00), receipt of which is hereby acknowledged, do hereby forever discharge and release South Carolina Electric and Gas Company (hereinafter SCE&G), and any and all other persons, firms, and corporations, their agents, employees, servants, heirs and successors, from any and all actions, causes of action, demands and/or claims of whatsoever nature which we may have in any way growing out of an incident which occurred on or about April 6, 2010, when Marthe Williams' back yard at 1532 Northland Drive in Cayce, South Carolina caught fire; to include any claims or causes of action that were or could have been asserted by Marthe Williams in that specific lawsuit Marthe Williams v. SCE&G, filed by Marthe Williams on or about April 5, 2013 in Lexington County Court of Common Pleas bearing docket number 2013-CP-32-01215; the consideration expressed herein constitutes a payment in full for all damages, losses and/or injuries to persons or property or both, whether known or unknown, developed or undeveloped, which have resulted or may result from the incident aforesaid.

We hereby declare and represent that the damages and/or injuries sustained may be permanent and/or progressive and that recovery therefrom is uncertain and indefinite, and that in making this Release, it is understood that we rely wholly on our own judgment, belief, and knowledge of the nature, extent and consequences of the damages and/or injuries and no representation or statement regarding any of the damages and/or injuries or regarding any other matter made by any of the persons, firms or corporations who are hereby released, or by any person or persons representing them or employed by them have influenced us to any extent whatsoever in making this Release.

It is further understood and agreed that the payment of the above amounts is not to be construed as an admission of liability on the part of the person or persons being released, liability by them being expressly denied.

We further understand and agree that any subrogated or third party interests, such as medical charges or Homeowners Insurance which were incurred as a result of the incident, must be satisfied in full from the proceeds of this settlement and we agree to hold harmless and indemnify SCE&G from any and all liability or responsibility with regard to such third party interests or liens, including any cost to enforce this provision or defend any actions brought by the third parties.

All agreements and understandings between the parties hereto are embodied herein and the terms of this Release are contractual and not a mere recital.

We have read the foregoing Release and understand it to be a full, final, and binding agreement.

IN WITNESS WHEREOF, we have hereunto set our hands and seals this ___ day of ____________, 2014.

WITNESSES:

____________________ ______________________________

Marthe Williams

____

STATE OF SOUTH CAROLINA)
)
COUNTY OF ____________________)

PERSONALLY appeared before me, ____________________________, who made oath
(Witness No. 1)

that (s)he saw the within named Marthe Williams sign the foregoing Release, and that (s)he, with ________________________ witnessed the execution thereof. (Witness No. 2)

____

(Witness No. 1)

Sworn to and subscribed before
me this _______ day of ________, 2014.

_________________________________(L.S.)
Notary Public for South Carolina
My Commission Expires: ___________

As attorney for the Plaintiff and a member of the South Carolina Bar, I do hereby approve the foregoing settlement and the execution of the Release set out hereinabove.

____
Christopher S. Leonard, Esquire
Kendrick & Leonard, P.C.

______________________, South Carolina

________________, 2014

SCANA®
POWER FOR LIVING

Matthew W. Gissendanner
Assistant General Counsel

matthew.gissendanner@scana.com

February 24, 2014

VIA ELECTRONIC MAIL AND U.S. FIRST CLASS MAIL

Mr. William P. Crawford
203 Tower Circle
Hendersonville, SC 28739-7910

RE: William P. Crawford v. South Carolina Electric & Gas Company;
Docket No. 2014-45-E

Dear Mr. Crawford:

It was a pleasure speaking with your wife this afternoon, and I am pleased that we were able to resolve the issues between you and South Carolina Electric & Gas Company ("SCE&G") concerning the above-referenced matter. This letter confirms that telephone conversation in which I informed your wife that SCE&G agrees to issue a credit in the amount of $299.74 to your account at 14 Lockwood Drive, Apartment 12I, Charleston, SC 29401. In exchange for the credit, your wife indicated that you would agree to withdraw the complaint that you filed with the Public Service Commission of South Carolina ("Commission") against SCE&G.

Based upon our conversation, I have instructed SCE&G to issue a credit of $299.74 to your account, and SCE&G has informed me that it has done so. SCE&G now asks that you withdraw the complaint you filed with the Commission. To this end, I have enclosed a draft letter for your signature to send to the Commission, informing it that you wish to withdraw your complaint.

Again, it was a pleasure speaking with your wife. If you have any questions or concerns, please do not hesitate to contact me.

Sincerely,

Matthew W. Gissendanner

Matthew W. Gissendanner

MWG/mcs
Enclosure

C. DUKES SCOTT
EXECUTIVE DIRECTOR

1401 Main Street, Suite 900
Columbia, SC 29201

OFFICE OF REGULATORY STAFF
ORS
SOUTH CAROLINA

NANETTE S. EDWARDS
DEPUTY EXECUTIVE DIRECTOR

Phone: (803) 737-0800
www.regulatorystaff.sc.gov

DAWN M. HIPP
DIRECTOR
UTILITY RATES and SERVICES

July 27, 2017

Mr. Dennis Gallipeau
1920 Ashford Lane.
Columbia, SC 29210

Re: PSC Docket No. 2017-198-E, Order No. 2017-446, Gallipeau vs. SCE&G

Dear Mr. Gallipeau:

This letter is in regard to your pending complaint at the Public Service Commission ("PSC") under Docket No. 2017-198-E. You have requested ORS summarize the details discussed with you during the July 17, 2017 conference call. In response to Order No. 2017-446 issued by the PSC on July 12, 2017, the ORS reviewed the complaints you filed with the PSC and the ORS related to SCE&G. ORS makes no changes in its original investigation findings which identified that SCE&G was in compliance with the PSC rules and regulations.

ORS employees, Brad Kirby, April Sharpe and Dawn Hipp, contacted you via telephone on July 17, 2017 to discuss your complaint and provide you with details of an offer of settlement to resolve your complaint. As we discussed, SCE&G is interested in resolving this matter and has offered the following to you:

1) SCE&G will remove the $1.58 late payment charge assessed on the May 9, 2017 bill;
2) SCE&G will remove the $1.81 late payment charge assessed on the June 9, 2017 bill;
3) SCE&G has offered to re-enroll your account in the Budget Billing Program at $90.00 per month effective as of the next bill, which SCE&G estimates will be generated on or about August 9, 2017;
4) SCE&G agrees to your request to pay the July bill of $63.65 by August 3, 2017; and
5) SCE&G requests you submit a letter to the PSC to withdraw your pending complaint.

During our call, you stated that that you currently do not want to go back on the Budget Bill Program. ORS discussed with you that there was a possibility that SCE&G could shift your bill issuance date to better align with your monthly income dates and that, if at a later date, you wish to enroll in the Budget Bill Program it would be made available to you provided the account has been paid and is current. SCE&G reviewed your account and is not able to further adjust your monthly billing date to better align with your monthly income dates.

Should you wish to accept the terms of the SCE&G offer, please submit your letter of complaint withdrawal to the PSC as soon as possible. If you have any questions you may contact me at 803-737-5206.

Sincerely,

Brad Kirby

Brad Kirby, Investigator
Office of Regulatory Staff, Consumer Services

Cc. SCE&G (via email)

RELEASE OF ALL CLAIMS – PROPERTY DAMAGE ONLY

Claim Number: SP-26500

That the Undersigned, being of lawful age, for sole consideration of SIXTY EIGHT THOUSAND FOUR HUNDRED SIXTY NINE DOLLARS & 00/100 cents --- ($68,469.00) to be paid to **Project Resources Group Inc.** does hereby and for its heirs, executors, administrators, successors, and assigns release, acquit and forever discharge **SCE&G** and its employees, agents, servants, successors, sub-contractors, heirs, executors, administrators, and all other related persons, firms, corporations, association or partnerships of and from any and all claims, actions, causes of action, demands, rights, damages, costs, loss of service, expenses and compensation whatsoever, which the undersigned now has/have or which may hereafter accrue on account of or in any way growing out of any and all **KNOWN AND UNKONWN, FORSEEN AND UNFORESEEN** property damages and the consequences thereof resulting or to result from the accident, casualty, or event which occurred **08/08/2016.**

1100 Sunset Drive Columbia, SC 29203

The undersigned further declare(s) and represent(s) that no promise, inducement or agreement not herein expressed has been made to the undersigned, and that this Release contains the entire agreement between the parties hereto, and that the terms of this Release are contractual and not a mere recital.

THE UNDERSIGNED HAS READ THE FOREGOING RELEASE AND FULLY UNDERSTANDS IT.

Signed and delivered this 16th day of November, 2016.

SPIRIT COMMUNICATIONS by
Authorized Representative, PRG

Lead Claim Specialist
TITLE

Kathleen M Meaux
Notary Public

KATHLEEN M. MEAUX
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID # 20084027874
MY COMMISSION EXPIRES 08-19-2020

FORM 10-K

SOUTH CAROLINA ELECTRIC & GAS CO - SCG

Filed: February 26, 2016 (period: December 31, 2015)

Annual report with a comprehensive overview of the company

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2015

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	**SCANA Corporation** (a South Carolina corporation)	**57-0784499**
1-3375	**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	**57-0248695**

Securities registered pursuant to Section 12(b) of the Act:

SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.

SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $7.2 billion at June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $50.65 per share. South Carolina Electric & Gas Company is a wholly-owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 19, 2016
SCANA Corporation	Without Par Value	142,916,917
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Specified sections of SCANA Corporation's Proxy Statement, in connection with its 2016 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other company.

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, “forward-looking statements” for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expects,” “forecasts,” “plans,” “anticipates,” “believes,” “estimates,” “projects,” “predicts,” “potential” or “continue” or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;

(2) legislative and regulatory actions, particularly changes in electric and gas services, rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;

(3) current and future litigation;

(4) changes in the economy, especially in areas served by subsidiaries of SCANA;

(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;

(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;

(7) the loss of sales to distributed generation, such as solar photovoltaic systems;

(8) growth opportunities for SCANA’s regulated and other subsidiaries;

(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;

(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA’s subsidiaries;

(11) changes in SCANA’s or its subsidiaries’ accounting rules and accounting policies;

(12) payment and performance by counterparties and customers as contracted and when due;

(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission, including nuclear generating facilities;

(14) the results of efforts to operate the Company's electric and gas systems and assets in accordance with acceptable performance standards, including the impact of additional distributed generation and nuclear generation;

(15) maintaining creditworthy joint owners for SCE&G’s new nuclear generation project;

(16) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon quality and prices, for our construction program, operations and maintenance;

(17) the results of efforts to ensure the physical and cyber security of key assets and processes;

(18) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;

(19) the availability of skilled, licensed and experienced human resources to properly manage, operate, and grow the Company’s businesses;

(20) labor disputes;

(21) performance of SCANA’s pension plan assets;

(22) changes in and realization of taxes and tax credits, including production tax credits for new nuclear units;

(23) inflation or deflation;

(24) compliance with regulations;

(25) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and

(26) the other risks and uncertainties described from time to time in the reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CB&I	Chicago Bridge & Iron Company N.V.
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of WEC and Stone and Webster
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker (decoupling mechanism)
CWA	Clean Water Act
DCGT	Dominion Carolina Gas Transmission LLC
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DSM Programs	Demand Side Management Programs
ELG Rule	Federal effluent limitation guidelines for steam electric generating units
Energy Marketing	The divisions of SEMI, excluding SCANA Energy
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
eWNA	Pilot Electric WNA
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRS	United States Internal Revenue Service
KVA	Kilovolt ampere
kWh	Kilowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LNG	Liquefied Natural Gas
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan

MATS	Mercury and Air Toxics Standards
MCF	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NASDAQ	The NASDAQ Stock Market, Inc.
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	A division of SEMI which markets natural gas in Georgia
SCE&G	South Carolina Electric & Gas Company
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
Southern Natural	Southern Natural Gas Company
Spirit Communications	SCTG Communications, Inc. (a wholly-owned subsidiary of SCTG, LLC) d/b/a Spirit Communications
Stone & Webster	Prior to December 31, 2015, CB&I Stone & Webster, a subsidiary of Chicago Bridge & Iron Company N.V. Effective December 31, 2015, Stone & Webster, a subsidiary of WECTEC, LLC, a wholly-owned subsidiary of WEC
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
WEC	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

INVESTOR INFORMATION

SCANA's and SCE&G's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at *www.scana.com* (which is not intended as an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC) as soon as reasonably practicable after these reports are filed or furnished.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's new nuclear project and other matters of interest to investors on SCANA's website. On SCANA's homepage, there is a yellow box containing links to the Nuclear Development and Other Investor Information sections of the website. The Nuclear Development section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear Development and Other Investor Information yellow box.

CORPORATE STRUCTURE AND SEGMENTS OF BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees of 5,829 as of February 19, 2016 and 5,886 as of February 20, 2015. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries except as described below, each of which is incorporated in South Carolina.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 698,000 customers and the purchase, sale and transportation of natural gas to approximately 347,000 customers (each as of December 31, 2015). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 534,000 residential, commercial and industrial customers (as of December 31, 2015). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

Nonregulated Businesses

SEMI markets natural gas in the southeast and provides energy-related services. SCANA Energy, a division of SEMI, sells natural gas to approximately 450,000 customers (as of December 31, 2015). Georgia's deregulated natural gas market includes approximately 1.6 million customers.

SCANA Services, Inc. provides administrative and management services to SCANA's other subsidiaries.

Disposals

CGT was sold to Dominion Resources, Inc. at the end of January 2015 and now operates as DCGT. SCI was sold to Spirit Communications in February 2015. In addition, SCANA owns two insignificant energy-related companies that are being liquidated.

For information with respect to major segments of business, see Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and Note 12 of the consolidated financial statements for SCANA and SCE&G. All such information is incorporated herein by reference.

COMPETITION

For a discussion of the impact of competition, see the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity and margins earned from those sales by customer classification as percentages of electric revenues were as follows:

	Sales		Margins	
Customer Classification	**2014**	**2015**	**2014**	**2015**
Residential	45%	45%	50%	50%
Commercial	32%	33%	33%	33%
Industrial	18%	17%	14%	14%
Sales for resale	2%	2%	1%	1%
Other	3%	3%	2%	2%
Total	100%	100%	100%	100%

Sales for resale include sales to three municipalities and one electric cooperative. Short-term system sales and margins were not significant for either period presented.

During 2015 SCE&G experienced a net increase of approximately 10,000 electric customers (growth rate of 1.5%), increasing its total electric customers to approximately 698,000 at year end.

For the period 2016-2018, SCE&G projects total territorial kWh sales of electricity to increase 1.4% annually (assuming normal weather), total retail sales to grow 1.4% annually (assuming normal weather), total electric customer base to increase 1.6% annually and territorial peak load (summer, in MW) to increase 2.4% annually. SCE&G projects a retail kWh sales decrease of approximately 1.1% and customer growth of 1.7% from 2015 to 2016. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%; however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a Unit Power Sales Agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system extends over a large part of the central, southern and southwestern portions of South Carolina. The system interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Santee Cooper, Georgia

Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) were as follows:

	Cost of Fuel Used		
	2013	2014	2015
Per MMBTU:			
Nuclear	$ 1.11	$ 1.01	$ 0.95
Coal	4.28	3.90	3.81
Natural Gas	4.63	5.19	3.26
All Fuels (weighted average)	3.53	3.62	3.01
Per Ton: Coal	104.63	96.74	95.69
Per MCF: Gas	4.69	5.30	3.35

The sources and percentages of total MWh generation by each category of fuel for the preceding three years and estimates for the next three years follow:

	% of Total MWh Generated					
	Actual			Estimated		
	2013	2014	2015	2016	2017	2018
Coal	45%	50%	39%	38%	40%	40%
Nuclear	24%	19%	20%	24%	21%	21%
Hydro	4%	3%	3%	3%	3%	3%
Natural Gas & Oil	26%	26%	36%	33%	34%	34%
Biomass/Solar	1%	2%	2%	2%	2%	2%
Total	100%	100%	100%	100%	100%	100%

For a listing of the Company's generating facilities, see the Electric Properties section within ITEM 2. PROPERTIES.

In 2015, coal was primarily obtained through long-term supply contracts with suppliers located in eastern Kentucky, Tennessee, Virginia, and West Virginia. These contracts provide for approximately 2.0 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2018. Spot market purchases may occur when needed or when prices are believed to be favorable. The Company relies on unit trains and, in some cases, trucks and barges for coal deliveries.

SCANA and SCE&G believe that SCE&G's operations comply with all applicable regulations relating to the discharge of sulfur dioxide and nitrogen oxide. See additional discussion at Environmental Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G, for itself and as agent for Santee Cooper, and Westinghouse are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G supplies enriched product to Westinghouse and Westinghouse supplies nuclear fuel assemblies for Summer Station Unit 1 and will supply assemblies for the New Units. Westinghouse will be SCE&G's exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Summer Station Unit 1 and the New Units through 2033. SCE&G is dependent upon Westinghouse for providing fuel assemblies for the new AP1000 reactors in the New Units in the current and anticipated future absence of other commercially viable sources.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of its nuclear generating units.

SCE&G stores spent nuclear fuel in its on-site spent-fuel pool, and has constructed a dry cask storage facility to accommodate the spent fuel output for the life of Summer Station Unit 1. In addition, Summer Station Unit 1 has sufficient on-site storage capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

SCE&G also uses long-term power purchase agreements to ensure that adequate power supply resources are in place to meet load obligations and reserve requirements. As of December 31, 2015, SCE&G had such agreements in place for 325 MW of capacity.

GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported were as follows:

	SCANA		SCE&G	
Customer Classification	**2014**	**2015**	**2014**	**2015**
Residential	54.9%	57.0%	44.1%	47.9%
Commercial	26.5%	26.8%	28.2%	28.0%
Industrial	12.4%	11.0%	24.6%	20.6%
Transportation Gas	6.2%	5.2%	3.1%	3.5%
Total	100.0%	100.0%	100.0%	100.0%

For the period 2016-2018, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.7% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.6%, commercial of 1.2% and industrial of 0.8%.

For the period 2016-2018, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.4% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.6%, commercial of 0.8% and industrial of 1.1%.

For the period 2016-2018, each of SCANA’s and SCE&G’s total regulated natural gas customer base is projected to increase 2.6% annually. During 2015 SCANA recorded a net increase of approximately 22,000 regulated gas customers (growth rate of 2.6%), increasing its regulated gas customers to approximately 881,000. Of this increase, SCE&G recorded a net increase of approximately 9,000 gas customers (growth rate of 2.7%), increasing its total gas customers to approximately 347,000 (as of December 31, 2015).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost, Supply and Curtailment Plans

SCE&G purchases natural gas under contracts with producers and marketers in both the spot and long-term markets. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2018), Transco (expiring at various times through 2031) and DCGT (expiring at various times through 2030). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 212,194 MMBTU from Southern Natural, 104,652 MMBTU from Transco and 449,727 MMBTU from DCGT. Additional natural gas volumes may be delivered to SCE&G’s system as capacity is available through interruptible transportation.

The daily volume of gas that SEMI is entitled to transport under service agreements with DCGT (expiring in 2016, 2017 and 2023) on a firm basis is 83,704 MMBTU.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $3.67 per MMBTU during 2015 and $5.48 per MMBTU during 2014.

SCE&G was allocated 5,502,600 MMBTU of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 4,558,600 MMBTU of gas were in storage on December 31, 2015. To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G supplements its supplies of natural gas with two LNG liquefaction storage facilities, one of which has liquefaction capability. The LNG plants are capable of storing the liquefied equivalent of 1,964,600 MMBTU of natural gas. Approximately 1,842,800 MMBTU (liquefied equivalent) of gas were in storage on December 31, 2015.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2032. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 710,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $4.12 per MMBTU during 2015 compared to $5.67 per MMBTU during 2014.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, Transco and Spectra Energy provide for storage capacity of approximately 13,000,000 MMBTU. Approximately 11,000,000 MMBTU of gas were in storage under these agreements at December 31, 2015. In addition, PSNC Energy’s LNG facility can store the liquefied equivalent of 1,000,000 MMBTU of natural gas with regasification capability of approximately 100,000 MMBTU per day. Approximately 900,000 MMBTU (liquefied equivalent) of gas were in storage at December 31, 2015. LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG provide for 1,300,000 MMBTU (liquefied equivalent) of storage space. Approximately 1,300,000 MMBTU (liquefied equivalent) were in storage under these agreements at December 31, 2015.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SEMI markets natural gas and provides energy-related services in the Southeast. In addition, SCANA Energy, a division of SEMI, markets natural gas to approximately 450,000 customers (as of December 31, 2015) in Georgia’s natural gas market. Georgia’s natural gas market includes approximately 1.6 million customers.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements for SCANA and SCE&G.

REGULATION

Regulatory jurisdictions to which SCANA and its subsidiaries are subject are described in the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	License Expiration
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

* SCE&G operates the Saluda hydroelectric project under an annual license while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, or may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and Note 2 to the consolidated financial statements for SCANA and SCE&G.

Fuel Cost Recovery Procedures

The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions. The definition also includes the cost of emission allowances used for sulfur dioxide, nitrogen oxide, mercury and particulates. In 2014, the South Carolina General Assembly amended the statutory definition of fuel cost thereby allowing electric utilities to recover avoided costs under the Public Utility Regulatory Policy Act of 1978. The South Carolina General Assembly further amended the fuel cost statute to allow for the recovery of costs incurred as a result of offering DER programs and net metering to its customers as a separate component of the overall fuel factor. SCE&G may request a formal proceeding concerning its fuel costs at any time.

Fuel cost recovery procedures related to the Company's natural gas operations along with related rate proceedings by the SCPSC and NCUC are described in Note 2 to the consolidated financial statements for SCANA and SCE&G.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of any new or pending regulations or standards upon existing operations cannot be predicted. For a discussion of how these regulations and standards may impact SCANA and SCE&G (including capital expenditures necessitated thereby), see the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements for SCANA and SCE&G.

OTHER MATTERS

Insurance coverage for SCE&G's nuclear units is described in Note 10 to the consolidated financial statements for SCANA and SCE&G.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to the Company, and where indicated the risk factors also relate to Consolidated SCE&G.

Commodity price changes, delays and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs) and availability. Any such changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to require the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial condition.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternate forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers on a volumetric rate structure unable to switch to alternate fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G. A regulatory mechanism applies to residential and commercial customers at PSNC Energy to mitigate the earnings impact of an increase or decrease in gas usage.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction for environmental compliance and its construction of the New Units and associated transmission, are significant and are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of the projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in energy generation and in other internal infrastructure projects, including projects for environmental compliance. For example, SCE&G and Santee Cooper have agreed to jointly own, contract the design and construction of, and operate the New Units, which will be two 1,250 MW (1,117 MW, net) nuclear units at SCE&G's Summer Station, in pursuit of which they have committed and are continuing to commit significant resources. In addition, construction of significant new transmission infrastructure is necessary to support the New Units and is under way as an integral part of the project. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and construction schedules may be affected by many variables, such as the regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness, unforeseen difficulties meeting critical regulatory requirements, contract disputes and litigation, and changes in key contractors or subcontractors. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects (including new baseload generation) as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, adverse changes in applicable laws and regulations, new or enhanced environmental or regulatory requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. Some of the foregoing issues have been experienced in the construction of the New Units. A discussion of certain of those matters can be found under New Nuclear Construction in Note 10 to the consolidated financial statements for SCANA and SCE&G.

Should the construction of the New Units adversely deviate from the schedules (by more than 18 months), estimates, and projections timely submitted to and approved by the SCPSC pursuant to the BLRA, the SCPSC could disallow the additional capital costs that result from the deviations to the extent that it is deemed that the Company's failure to anticipate or avoid the deviation, or to minimize the resulting expenses, was imprudent, considering the information available at the time. Depending upon the magnitude of any such disallowed capital costs, the Company could be moved to evaluate the prudency of continuation, adjustment to, or termination of the project.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to the risk that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, new joint owners cannot be secured at equivalent financial terms, or changes in the joint ownership make-up will increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows and financial condition, as well as our qualifications for applicable governmental programs and benefits, such as production tax credits, may be adversely affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e., natural gas) market risk. We could be required to provide cash collateral or recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract.

The Company strives to manage commodity price exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand and other changes in commodity prices). We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be diminished.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental commissions, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our businesses. In addition to many other aspects of our businesses, these requirements impact the services mandated or offered to our customers, and the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. Non-compliance with these requirements by third parties, such as our contractors, vendors and agents, may subject the Company and Consolidated SCE&G to operational risks and to liability. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's or Consolidated SCE&G's businesses. Non-compliance with these laws and regulations could result in fines, litigation, loss of licenses or permits, mandated capital expenditures and other adverse business outcomes, as well as reputational damage, which could adversely affect the cash flows, results of operations, and financial condition of the Company and Consolidated SCE&G.

Furthermore, changes in or uncertainty in monetary, fiscal, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G could be adversely impacted by changes in tax policy, such as the loss of production tax credits related to the construction of the New Units.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects, results of DSM Programs and/or increases in operating costs may lead to requests for regulatory relief, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits.

SCE&G's electric operations in South Carolina and the Company's gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. Consolidated SCE&G's generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. SCE&G's electric transmission system is subject to extensive regulations and oversight from the SCPSC, NERC and FERC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as market conditions evolve.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement, many of which are still pending final action by those federal agencies. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers and major swap participants, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers or major swap participants, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Moreover, the Company retains reporting responsibility for certain types of swaps, such as the annual reporting of trade options. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Although we believe that we have constructive relationships with the regulators, our ability to obtain rate treatment that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing nitrogen oxide, sulfur dioxide, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per MWh. No new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. However, on February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. Also, a number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none have yet been enacted. In April 2012 the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. In October 2014, the stay on CSAPR was lifted and CAIR was set aside, thus reinstating CSAPR sulfur dioxide and nitrogen oxide allocations on electric generating units in 28 states, including South Carolina. In 2010, the EPA set a new NAAQS limit for sulfur dioxide and in August 2015 issued the Data Requirements Rule for implementing the one-hour sulfur dioxide standard. In October 2015 a new NAAQS limit for ozone was finalized by the EPA. The EPA's rule for cooling water intake structures to meet the best technology available became effective in October 2014, and the EPA also issued a final rule in December 2014 regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA finalized new standards under the CWA governing effluent limitation guidelines for electric generating units in September 2015.

Compliance with these environmental laws and regulations requires us to commit significant resources toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as the clean-up of MGP sites or additional emission allowances) or require us to incur additional expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our industry, our businesses and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. In June 2014 the State of South Carolina enacted legislation known as Act 236 with the stated goal for each investor-owned utility to add up to 2% of its 5-year average retail peak demand with renewable electric generation resources by the end of 2020. A utility, at its option, may add an additional 1% during this period. Such renewable energy may not be readily available in our service territories and could be costly to build, acquire, and operate. Resulting increases in the price of electricity to recover the cost of these types of generation, as approved by regulatory commissions, could result in significantly lower usage of electricity by our customers. In addition, DER generation at customers' facilities could result in the loss of sales to those customers. Compliance with potential future portfolio standards could significantly impact our industry, our capital expenditures, and our results of operations and financial condition.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In effecting compliance with MATS, SCE&G has retired three of its oldest and smallest coal-fired units and converted three others such that they may be gas-fired.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and we may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company's and Consolidated SCE&G's business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company's and Consolidated SCE&G's ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and its actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA's pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition, including its shareholders' equity.

A downgrade in the credit rating of SCANA or any of SCANA's subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies currently rate SCANA's long-term senior unsecured debt, SCE&G's long-term senior secured debt, and the long-term senior unsecured debt of PSNC Energy as investment grade. In addition, rating agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of our rated companies' commonly monitored financial credit metrics could adversely affect their debt ratings. If these rating agencies were to downgrade any of these ratings, particularly to below investment grade for long-term ratings, borrowing costs on new issuances would increase, which would diminish financial results, and the potential pool of investors and funding sources could decrease.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and received lower prices for natural gas in deregulated markets when weather conditions have been milder than normal, and as a consequence earned less income from those operations. During 2010 the SCPSC approved SCE&G's implementation of an eWNA on a pilot basis; it was discontinued at the end of 2013. Mild weather in the future could diminish the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as electromagnetic events and the 2011 earthquake and tsunami in Japan) or man-made mishaps (such as the San Bruno, California natural gas transmission pipeline failure, the Kingston, Tennessee coal ash pond failure, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial condition, operating expenses, and cash flows.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via a RTO/ISO (Regional Transmission Organization/Independent System Operator) is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should a RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new delivery transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets would be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems, which systems have undergone a rapid decline in their costs. As a result of federal and state subsidies, potential regulations allowing third-party retail sales, and advances in distributed generation technology, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and slow growth, potentially causing higher rates to customers.

The Company and SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Some economic sectors important to our customer base may be particularly affected. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally or legislative or regulatory actions. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns. For instance, improvements in energy storage technology, if realized, could have dramatic impacts on the viability of and growth in distributed generation.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be significantly harmed.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission equipment failure, information systems failure or security breach, natural disasters, and the effects of a pandemic or terrorist attack on our workforce or facilities or on the ability of vendors and suppliers to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The operation of the New Units or the integration of a significant amount of distributed generation into our systems may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a natural gas line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's revenues, results of operations, and financial condition. Insurance may not be available or adequate to respond to these events.

A failure of the Company to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's financial condition, results of operations and cash flows.

The Company depends on maintaining the physical and cyber security of its operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our businesses could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's operations are dependent in some manner upon our cyber systems, which encompass electric and gas operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, employee, or corporate information. The Company may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to respond to these events. As a result, the Company's financial condition, results of operations, and cash flows may be adversely affected.

SCANA's ability to pay dividends and to make payments on SCANA's debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital.

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SEMI, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of Consolidated SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition. These risks will increase as the New Units are developed.

In 2015, Summer Station Unit 1, operated by SCE&G, provided approximately 4.7 million MWh, or 20% of our generation. When the New Units are completed, our generating capacity and the percentage of total generating capacity represented by nuclear sources are expected to increase. Hence, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. Although we have no reason to anticipate a serious nuclear incident, a major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit, resulting in costly changes to units under construction or in operation and harming our results of operations, cash flows and financial condition. Furthermore, a major incident at a domestic nuclear facility could result in retrospective premium assessments under our nuclear insurance coverages. Finally, in today's environment, there is a heightened risk of terrorist attack on the nation's nuclear facilities, which has resulted in increased security costs at our nuclear plant.

Failure to retain and attract key personnel could adversely affect the Company's and Consolidated SCE&G's operations and financial performance.

As with many other utilities, a significant portion of our workforce will be eligible for retirement during the next few years. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our businesses. Competition for these employees is high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. In particular, the timely hiring, training, licensing and retention of personnel needed for the operation of the New Units is necessary to maintain the schedule for their operation. Further, the Company's or Consolidated SCE&G's ability to construct or maintain generation or other assets requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance. Furthermore, increased medical benefit costs of employees and retirees could adversely affect the results of operations of the Company and Consolidated SCE&G. Medical costs in this country have risen significantly over the past number of years and are expected to continue to increase at unpredictable rates. Such increases, unless satisfactorily managed by the Company and Consolidated SCE&G, could adversely affect results of operations.

The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial condition, and access to capital.

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes, including customers' concerns regarding rate increases such as those periodic rate increases under the BLRA, may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously supported by legislation or approved by regulators), to the detriment of the Company or Consolidated SCE&G (e.g., revision or repeal of the BLRA). Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company's or Consolidated SCE&G's interests, may have a negative effect on our results of operations, cash flows and financial condition, as well as limit our ability to access capital.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards of compliance with laws and regulations, ethical conduct, operational effectiveness, customer service and the safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company's and Consolidated SCE&G's access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to focus on the safety of employees, customers and the public, to maintain the privacy of information related to our customers and employees and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. Traditional news media and social media can very rapidly convey information, whether factual or not, to large numbers of people, including customers, investors, regulators, legislators and other stakeholders, and the failure to effectively manage timely communication through these channels could adversely impact our reputation. The Company and Consolidated SCE&G also are committed to operational excellence, to quality customer service, and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments may subject the Company and Consolidated SCE&G not only to fraud, regulatory action, litigation and financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries. See also Note 13 to the consolidated financial statements of SCANA.

SCE&G's bond indenture, which secures its First Mortgage Bonds, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

Electric Properties

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2015.

	In-Service Date	Net Generating Capacity Summer (MW)	
Coal-Fired Steam:			
Wateree - Eastover, SC	1970	684	
Williams - Goose Creek, SC	1973	605	
Cope - Cope, SC	1996	415	
Kapstone - Charleston, SC	1999	85	
Gas-Fired Steam:			
McMeekin - Irmo, SC	1958	250	*
Urquhart Unit 3 - Beech Island, SC	1953	95	
Nuclear:			
Summer Station Unit 1 - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647	
Summer Station Unit 2 and Unit 3 - Parr, SC			**
Internal Combustion Turbines:			
Peaking units - various locations in SC	1968-2010	349	
Urquhart Combined Cycle - Beech Island, SC	2002	458	
Jasper Combined Cycle - Jasper, SC	2004	852	
Hydro:			
Saluda - Irmo, SC	1930	200	
Other hydro units - various locations in or bordering SC	1905-1914	18	
Fairfield Pumped Storage - Parr, SC	1978	576	

* McMeekin units were fueled with coal and natural gas during 2015. The Company expects to burn natural gas exclusively beginning in early 2016.
** SCE&G owns 55% of Unit 2 and Unit 3, which are being constructed at Summer Station.

SCE&G owns 435 substations having an aggregate transformer capacity of 31.0 million KVA. The transmission system consists of 3,450 miles of lines, and the distribution system consists of 18,478 pole miles of overhead lines and 7,264 trench miles of underground lines.

Natural Gas Distribution and Transmission Properties

SCE&G's natural gas system includes 447 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and DCGT. SCE&G's distribution system consists of 17,046 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6,180 MMBTU per day and store the liquefied equivalent of 1,009,400 MMBTU of natural gas. The Salley facility can store the liquefied equivalent of 927,000 MMBTU of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 61,800 MMBTU per day at Charleston and 92,700 MMBTU per day at Salley.

PSNC Energy's natural gas system consists of 613 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy's distribution system consists of 21,268 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000,000 MMBTU, the capacity to liquefy up to 4,000 MMBTU per day and the capacity to regasify approximately 100,000 MMBTU per day.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G are subject to various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on their respective results of operations, cash flows or financial condition. In addition, certain material regulatory and environmental matters and uncertainties, some of which remain outstanding at December 31, 2015, are described in the Rate Matters section of Note 2 and in the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	60	Chairman of the Board and Chief Executive Officer	2011-present
		President and Chief Operating Officer-SCANA	*-present
		President-SCE&G	*-2011
Jimmy E. Addison	55	Executive Vice President-SCANA	2012-present
		Chief Financial Officer	*-present
		President and Chief Operating Officer-SEMI	2014-present
		Senior Vice President	*-2012
Jeffrey B. Archie	58	Senior Vice President and Chief Nuclear Officer-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Sarena D. Burch	58	Senior Vice President-Risk Management and Corporate Compliance Senior Vice President-Fuel Procurement and Asset Management-SCE&G	2016-present
		and PSNC Energy	*-2015
		Senior Vice President-SCANA	*-2015
Stephen A. Byrne	56		2011-present
		President-Generation and Transmission-SCE&G Chief Operating Officer-SCE&G	*-present
		Executive Vice President-SCANA	*-present
		Executive Vice President-Generation and Transmission-SCE&G	*-2011
D. Russell Harris	51	Senior Vice President-Gas Distribution-SCANA	2013-present
		President-Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		Senior Vice President-SCANA	2012-2013
Kenneth R. Jackson	59		
		Senior Vice President-Economic Development, Governmental and Regulatory Affairs	2014-present
		Senior Vice President-SCANA	2014-present
		Vice President-Rates and Regulatory Services	*-2014
W. Keller Kissam	49	President of Retail Operations-SCE&G	2011-present
		Senior Vice President-SCANA	2011-present
		Senior Vice President-Retail Operations-SCE&G	*-2011
Ronald T. Lindsay	65	Senior Vice President, General Counsel and Assistant Secretary	*-present
Martin K. Phalen	61	Senior Vice President-Administration-SCANA	2012-present
		Vice President-Gas Operations-SCE&G	*-2012

*Indicates positions held at least since February 26, 2011.

PART II
ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

SCANA Corporation:

Price Range (NYSE Composite Listing):

	2015				2014			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 61.95	$ 57.73	$ 56.26	$ 65.57	$ 63.41	$ 53.89	$ 53.88	$ 51.39
Low	$ 54.84	$ 50.17	$ 47.77	$ 52.03	$ 47.77	$ 48.53	$ 49.51	$ 45.58

SCANA common stock trades on the NYSE using the ticker symbol SCG. At February 19, 2016 there were 142,916,917 shares of SCANA common stock outstanding which were held by approximately 26,000 shareholders of record. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2015, see ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

SCANA declared quarterly dividends on its common stock of $0.545 per share in 2015 and $0.525 per share in 2014. On February 18, 2016, SCANA increased the quarterly cash dividend rate on SCANA common stock to $0.575 per share, an increase of approximately 5.5%. The next quarterly dividend is payable April 1, 2016 to shareholders of record on March 10, 2016. For a discussion of provisions that could limit the payment of cash dividends, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCANA.

The following table provides information about purchases by or on behalf of SCANA or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934) during the fourth quarter of 2015 of shares or other units of any class of SCANA's equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934:

Issuer Purchases of Equity Securities

	(a)	(b)	(c)	(d)
Period	Total number of shares (or units) purchased	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1-31	268,139	$ 56.51	268,139	
November 1-30	71,699	$ 59.19	71,699	
December 1-31	68,761	$ 59.57	68,761	
Total	408,599		408,599	*

*On December 16, 2014 SCANA announced a program to convert from original issue to open market purchase of SCANA common stock for all applicable compensation and dividend reinvestment plans once the sales of certain subsidiaries were completed. The sales of the subsidiaries were completed in the first quarter of 2015. This program has no stated maximum number of shares that may be purchased and no stated expiration date.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2015 and 2014, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount
February 20, 2014	$ 62.5 million	February 20, 2015	$ 69.0 million
April 24, 2014	62.8 million	April 30, 2015	67.8 million
July 31, 2014	66.8 million	July 30, 2015	68.4 million
October 30, 2014	72.5 million	October 29, 2015	72.3 million

On February 18, 2016, SCE&G declared a quarterly dividend on its common stock of $72.2 million.

For a discussion of provisions that could limit the payment of cash dividends, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCE&G.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2015	2014	2013	2012	2011
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$ 4,380	$ 4,951	$ 4,495	$ 4,176	$ 4,409
Operating Income	$ 1,308	$ 1,007	$ 910	$ 859	$ 813
Net Income	$ 746	$ 538	$ 471	$ 420	$ 387
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.9	141.9	138.7	131.1	128.8
Basic Earnings Per Share	$ 5.22	$ 3.79	$ 3.40	$ 3.20	$ 3.01
Diluted Earnings Per Share	$ 5.22	$ 3.79	$ 3.39	$ 3.15	$ 2.97
Dividends Declared Per Share of Common Stock	$ 2.18	$ 2.10	$ 2.03	$ 1.98	$ 1.94
Balance Sheet Data					
Utility Plant, Net	$ 13,145	$ 12,232	$ 11,643	$ 10,896	$ 10,047
Total Assets	$ 17,146	$ 16,818	$ 15,127	$ 14,568	$ 13,476
Total Equity	$ 5,443	$ 4,987	$ 4,664	$ 4,154	$ 3,889
Short-term and Long-term Debt	$ 6,529	$ 6,581	$ 5,788	$ 5,707	$ 5,274
Other Statistics					
Electric:					
Customers (Year-End)	698,372	687,800	678,273	669,966	664,196
Total sales (Million kWh)	23,102	23,319	22,313	23,879	24,188
Generating capability-Net MW (Year-End)	5,234	5,237	5,237	5,533	5,642
Territorial peak demand-Net MW	4,970	4,853	4,574	4,761	4,885
Regulated Gas:					
Customers, excluding transportation (Year-End)	881,295	859,186	837,232	818,983	803,644
Sales, excluding transportation (Thousand Therms)	875,218	973,907	921,533	798,978	812,416
Transportation customers (Year-End)	627	656	667	663	645
Transportation volumes (Thousand Therms)	791,402	1,786,897	1,729,399	1,559,542	1,585,202
SCE&G:					
Statement of Income Data					
Operating Revenues	$ 2,930	$ 3,091	$ 2,845	$ 2,809	$ 2,819
Operating Income	$ 934	$ 830	$ 737	$ 717	$ 654
Net Income	$ 480	$ 458	$ 391	$ 352	$ 316
Net Income Attributable to Noncontrolling Interest	$ 14	$ 12	$ 11	$ 11	$ 10
Earnings Available to Common Shareholder	$ 466	$ 446	$ 380	$ 341	$ 306
Balance Sheet Data					
Utility Plant, Net	$ 11,589	$ 10,783	$ 10,048	$ 9,375	$ 8,588
Total Assets	$ 14,765	$ 14,078	$ 12,673	$ 12,078	$ 11,006
Total Equity	$ 5,151	$ 4,757	$ 4,489	$ 4,043	$ 3,773
Short-term and Long-term Debt	$ 5,189	$ 4,989	$ 4,279	$ 4,145	$ 3,730
Other Statistics					
Electric:					
Customers (Year-End)	698,383	687,866	678,338	670,030	664,273
Total sales (Million kWh)	23,115	23,333	22,327	23,899	24,200
Generating capability-Net MW (Year-End)	5,234	5,237	5,237	5,533	5,642
Territorial peak demand-Net MW	4,970	4,853	4,574	4,761	4,885
Regulated Gas:					
Customers, excluding transportation (Year-End)	347,447	338,274	329,179	322,419	316,683
Sales, excluding transportation (Thousand Therms)	425,661	471,596	457,119	412,163	407,073
Transportation customers (Year-End)	172	173	173	166	155
Transportation volumes (Thousand Therms)	206,990	198,733	155,190	260,215	192,492

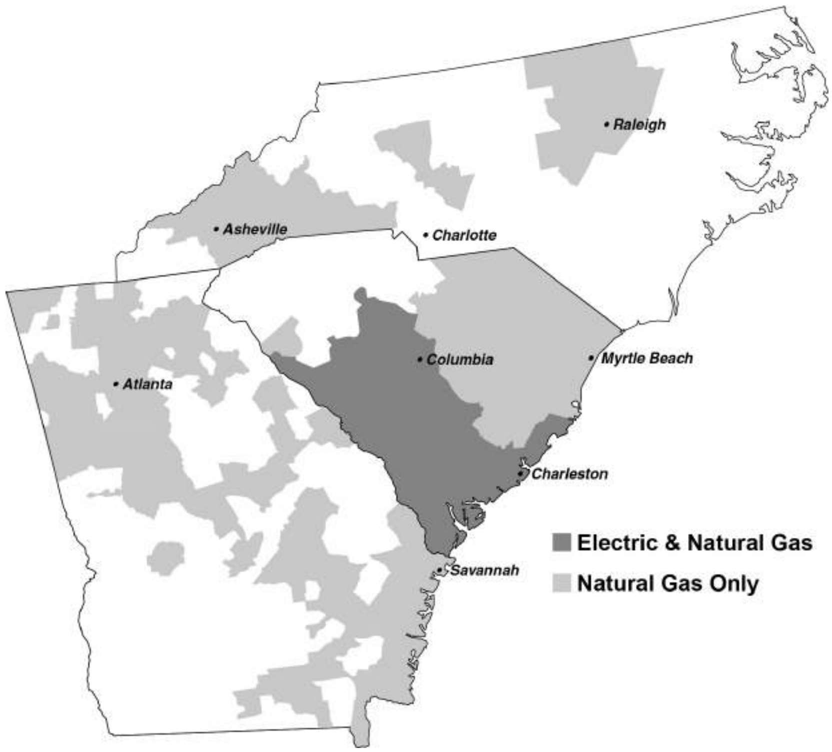
For information on the impact of certain dispositions on SCANA's selected financial data, see Note 13 to SCANA's consolidated financial statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

The following map indicates areas where the Company’s significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect net income earned by the Company’s regulated and nonregulated businesses (including the holding company) and the percentage of total assets held by them.

	2015	2014	2013
Net Income			
Regulated	90%	98%	97%
Nonregulated	10%	2%	3%
Assets			
Regulated	97%	95%	95%
Nonregulated	3%	5%	5%

In the first quarter of 2015, SCANA closed on the sales of its interstate natural gas pipeline and telecommunications subsidiaries. The differences between 2014 and 2015 percentages of net income from regulated and nonregulated businesses are attributable to these sales. See Note 13 to the consolidated financial statements.

Key Earnings Drivers and Outlook

During 2015, economic growth continued to improve in the southeast. In the Company's South Carolina and North Carolina service territories, companies announced plans during the year to invest over $2 billion, with the expectation of creating approximately 6,500 jobs. South Carolina's unemployment rate ended December 2015 at 5.5%, a drop of 1% over 2014, an improvement that takes on greater significance when considering that almost 80,000 more South Carolinians were employed at the end of 2015 over 2014. In addition, each of the Company's regulated businesses experienced positive customer growth year over year.

Over the next five years, key earnings drivers for the Company will be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business in Georgia and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generates electricity and provides for its transmission, distribution and sale to approximately 698,000 customers (as of December 31, 2015) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity against other energy sources.

Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2015 was 10.25% for non-BLRA rate base and 11.0% for BLRA-related rate base. To prevent the need for a non-BLRA base rate increase during years of peak nuclear construction, SCE&G has a stated goal of earning a return on equity for non-BLRA rate base of 9% or higher. For the year ended December 31, 2015, SCE&G's earned return on equity related to non-BLRA rate base was approximately 9.75%.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and SCE&G has agreed to acquire an additional 5% ownership from Santee Cooper in increments beginning with the commercial operation date of Unit 2. The purchase of this additional 5% ownership is expected to be funded by increased cash flows resulting from tax deductibility of depreciation associated with the New Units when they enter commercial operation.

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. As of December 31, 2015, SCE&G's investment in the New Units totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

In September 2015, the SCPSC approved an updated BLRA milestone schedule and certain updated owner's costs and other capital costs, some of which were associated with schedule delays and other contested costs. Also in September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%, to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding certain disputes, and the EPC Contract was amended. The October 2015 Amendment became effective on December 31, 2015, and among other things, it resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium. The October 2015 Amendment also provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project after June 30, 2015, subject to certain exceptions.

On November 19, 2015, SCE&G held an allowable *ex parte* communication briefing with the SCPSC to describe SCE&G's settlement with the Consortium. During that briefing, the Company provided the following summary of key points related to the SCPSC's September 2015 order and the October 2015 Amendment.

	SCPSC Order #2015-661 September 2015	**October 2015 Amendment**	**Fixed Price Option Under the October 2015 Amendment**
Guaranteed Substantial Completion Dates	Unit 2 - June 2019 Unit 3 - June 2020	Unit 2 - August 2019 Unit 3 - August 2020	
Capital Cost (SCE&G's 55% share)	$5.247 billion	$5.492 billion	$6.757 billion
Future Escalation to WEC*	$794 million	$813 million	$19 million
Total Expected Project Cost (SCE&G's 55% share)	$6.827 billion	$7.113 billion	$7.601 billion
Liquidated Damages	$155 million at 100%$86 million - SCE&G	$926 million at 100% $509 million - SCE&G	$676 million at 100% $372 million - SCE&G
Bonuses	Capacity Performance Related	Completion - Capacity Performance bonus removed $550 million at 100% $303 million - SCE&G	$300 million at 100% $165 million - SCE&G
Change in Law Language	Generally defined	Explicitly defined - Formal written adoption of a new statute, regulation, requirement, or code or new NRC regulatory requirement that did not exist as of this amendment	

* The fixed price option, regardless of date of acceptance, would fix project costs and shift the risk of escalation (excluding escalation primarily on owner's and transmission costs) to WEC as of June 30, 2015. Total gross escalation recorded as of June 30, 2015 is $386 million. Under the fixed price option, total gross escalation remaining on the project is estimated to be approximately $145 million.

Following an evaluation as to whether to exercise the fixed price option, SCE&G expects to file a petition, as provided under the BLRA, for an update to the project's estimated capital cost schedule which would incorporate the impact of the October 2015 Amendment. Refer to the Exhibit Index for information on where a copy of the October 2015 Amendment is available publicly.

The information summarized above, as well as additional information on these and other related matters, is further discussed at Note 2 and Note 10 to the consolidated financial statements.

Environmental

EPA regulations have a significant impact on the Company's electric operations. In 2015, several regulations were proposed or became final, including the following:

- On June 29, 2015, the Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate mercury and other specified air pollutants under the MATS rule, but did not vacate MATS. The EPA has indicated that it expects to issue a revised rule responsive to the issue raised by the Supreme Court by April 15, 2016. SCE&G and GENCO have received a one-year extension (until April 2016) to comply with MATS at certain of their generating stations. These extensions will allow time to convert one generating station to burn natural gas and to install additional pollution control devices at other generating stations. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

- A revised standard for new power plants under the CAA was proposed on August 3, 2015, and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. This rule effectively prevents construction of new coal-fired plants without partial carbon capture and sequestration capabilities.

- On August 3, 2015, the EPA issued its final rule under the Clean Power Plan that would regulate carbon dioxide emissions from existing units. This rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. Any costs incurred to comply with such rule are expected to be recoverable through rates.

- The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved in connection with the renewal (every five years) of state-issued NPDES permits. The ELG Rule became effective January 4, 2016. SCE&G and GENCO expect that wastewater treatment technology retrofits will be required at two generating stations and may be required at other facilities. The extent of the station-specific retrofits required and the related schedule for compliance will be determined in connection with each plant's NPDES permit renewal.

- New federal regulations affecting the management and disposal of CCRs became effective in the fourth quarter of 2015. Under these regulations, CCRs will not be regulated as hazardous waste. These regulations do impose certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. These regulations are not expected to have a material effect on SCE&G and GENCO because SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The above environmental initiatives and similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, the Company cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on the Company, if any. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 881,000 retail customers (as of December 31, 2015) in portions of South Carolina and North Carolina in areas covering approximately 35,000 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25% for SCE&G and 10.60% for PSNC Energy.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company's ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at such levels for the foreseeable future. The supply of natural gas from the Marcellus and Utica shale basins in West Virginia, Pennsylvania and Ohio has prompted companies unaffiliated with SCANA to propose a 550-mile pipeline that would bring natural gas from these basins to Virginia and North Carolina. If successful, the completed pipeline may drive economic development along its path, including areas within PSNC Energy's service territory, and may serve to keep natural gas competitively priced in the region.

Retail Gas Marketing

SCANA Energy, a division of SEMI, sells natural gas to approximately 450,000 customers (as of December 31, 2015) throughout Georgia. This market is mature, resulting in lower margins and stiff competition. Competitors include affiliates of large energy companies as well as electric membership cooperatives, among others. SCANA Energy's ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy's operating results are sensitive to weather.

As Georgia's regulated provider, SCANA Energy provides service to customers considered to be low-income or that are otherwise unable to obtain natural gas service from other marketers. SCANA Energy provides this service at rates approved by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA Energy and certain of SCANA's other natural gas distribution and marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or placed under contract.

Energy Marketing

The divisions of SEMI, excluding SCANA Energy, market natural gas in the southeast and provide energy-related services to customers. Operating results for energy marketing are primarily influenced by customer demand for natural gas and the ability to control costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, certain pipeline capacity available for Energy Marketing to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the retail market.

RESULTS OF OPERATIONS

Earnings Per Share

The Company reports earnings determined in accordance with GAAP. Management believes that, in addition to reported earnings under GAAP, the Company's GAAP-adjusted weather-normalized net earnings (and earnings per share) provide a meaningful representation of its fundamental earnings power and can aid in performing period-over-period financial analysis and comparison with peer group data. In management's opinion, in addition to operating income for regulated businesses, GAAP-adjusted weather-normalized net earnings (and earnings per share) are a useful indicator of the financial results of the Company's primary businesses. These measures are also a basis for management's provision of earnings guidance and growth projections and are used in part by management in making budgetary and operational decisions including determining eligibility for certain incentive compensation payments. These non-GAAP performance measures are not intended to replace the GAAP measures of net earnings (or earnings per share), but are offered as supplements to it. A reconciliation of GAAP earnings per share to GAAP-adjusted weather-normalized net earnings per share follows:

	2015	2014	2013
GAAP basic earnings per share	$ 5.22	$ 3.79	$ 3.40
Deduct:			
Gain on sale of CGT	0.95	—	—
Gain on sale of SCI	0.46	—	—
SCE&G Electric - effect of abnormal weather	0.08	0.21	—
GAAP-adjusted weather-normalized basic earnings per share	$ 3.73	$ 3.58	$ 3.40
GAAP diluted earnings per share	$ 5.22	$ 3.79	$ 3.39
GAAP-adjusted weather-normalized diluted earnings per share	$ 3.73	$ 3.58	$ 3.39
Cash dividends declared per share	$ 2.18	$ 2.10	$ 2.03

2015 vs 2014

Earnings per share on a GAAP basis increased due to the sale of CGT and SCI, higher electric margins, lower operation and maintenance expenses and lower depreciation expense. These increases were partially offset by lower gas margins, higher property taxes, lower other income, higher interest expense, a higher effective tax rate and dilution from additional shares outstanding, as further described below.

2014 vs 2013

Basic earnings per share on a GAAP basis increased primarily due to the effects of weather, customer growth and base rate increases under the BLRA. Higher electric and gas margins were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.

Discussion of above adjustments:

The sales of CGT and SCI were closed in the first quarter of 2015. These subsidiaries operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. Therefore, CGT and SCI were not a part of the Company's core business. See Note 13 to the consolidated financial statements. In aggregate, these subsidiaries contributed basic earnings per share of $.02 in 2015, $.14 in 2014 and $.15 in 2013.

SCE&G estimates the effects of abnormal weather on its electric business by comparing actual temperatures in its service territory to a historical average. The result is used in developing an estimate of electric margin revenue, using average margin rates, attributable to the effects of abnormal weather. In 2013 the Company's eWNA was still in place, so therefore there was no effect of abnormal weather on the Company's electric margin. In January 2014 the eWNA was terminated by order of the SCPSC.

Management believes the above adjustments are appropriate in determining the non-GAAP financial performance measures. Such non-GAAP measures reflect management's decision that wholesale gas transportation and telecommunications operations were not a part of the Company's core businesses and would not align with the Company's commitment to serve retail customers on a long-term basis. The non-GAAP measures also provide a consistent basis upon which to measure performance by excluding the effects on per share earnings of abnormal weather in the electric business.

Diluted earnings per share figures give effect to dilutive potential common stock using the treasury stock method. See Note 1 to the consolidated financial statements.

On February 18, 2016, SCANA declared a quarterly cash dividend on its common stock of $.575 per share.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 2,557.1	(2.7)%	$ 2,629.4	8.2%	$ 2,430.5
Less: Fuel used in electric generation	660.6	(17.4)%	799.3	6.4%	751.0
Purchased power	52.1	(35.4)%	80.7	87.7%	43.0
Margin	1,844.4	5.4 %	1,749.4	6.9%	1,636.5
Other operation and maintenance expenses	497.1	0.5 %	494.8	3.2%	479.6
Depreciation and amortization	277.3	(7.7)%	300.3	1.2%	296.7
Other taxes	194.5	4.2 %	186.7	3.2%	180.9
Operating Income	$ 875.5	14.1 %	$ 767.6	13.0%	$ 679.3

2015 vs 2014

- Margin increased due to downward adjustments of $69.0 million in 2014, compared to downward adjustments of $19.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and DSM Programs. These adjustments had no effect on net income as they were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts, lower depreciation expense upon the adoption and implementation of revised depreciation rates as a result of an updated depreciation study and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve. Margin also increased due to base rate increases under the BLRA of $65.7 million and residential and commercial customer growth of $21.4 million. These increases were partially offset by $25.6 million due to the effects of weather, lower industrial margins of $14.6 million primarily due to variable price contracts, and lower collections under the rate rider for pension costs of $3.0 million. See Note 2 to the consolidated financial statements.

- Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider collections.
- Depreciation and amortization decreased by $28.7 million in 2015 due to the implementation of the above mentioned revised depreciation rates, $14.5 million of which was offset by downward revenue adjustments. This decrease in depreciation expense was partially offset by increases associated with net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Electric margin increased due to the effects of weather of $43.5 million, base rate increases under the BLRA of $54.1 million and customer growth of $14.7 million. These margin increases were partially offset by downward adjustments of $69.0 million in 2014, compared to downward adjustments of $50.1 million in 2013, pursuant to SCPSC orders related to fuel cost recovery, the reversal of undercollected amounts related to SCE&G's eWNA program (the eWNA was discontinued effective with the first billing cycle of 2014) and DSM Programs. Such adjustments are fully offset by the recognition within other income of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve, both of which had been deferred in regulatory accounts. See Note 2 to the consolidated financial statements.
- Operations and maintenance expenses increased due to nonlabor operating expenses of $8.9 million, DSM Programs cost amortization of $2.1 million, higher labor expense of $1.1 million which includes incentive compensation and lower pension cost recognition, storm expenses of $1.1 million and other general expenses of $1.9 million.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2015	Change	2014	Change	2013
Residential	7,978	(2.2)%	8,156	7.7	7,571
Commercial	7,386	0.2 %	7,371	2.3%	7,205
Industrial	6,201	(0.5)%	6,234	3.9%	6,000
Other	595	(0.8)%	600	3.3%	581
Total retail sales	22,160	(0.9)%	22,361	4.7%	21,357
Wholesale	942	(1.7)%	958	0.3%	955
Total Sales	23,102	(0.9)%	23,319	4.5%	22,312

2015 vs 2014

Retail sales volumes decreased primarily due to the effects of weather, partially offset by customer growth.

2014 vs 2013

Retail sales volumes increased primarily due to the effects of weather and customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas Distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 811.7	(20.0)%	$ 1,014.0	7.6%	$ 942.6
Less: Gas purchased for resale	383.7	(35.2)%	592.5	10.8%	534.9
Margin	428.0	1.5 %	421.5	3.4%	407.7
Other operation and maintenance expenses	161.4	4.3 %	154.8	1.4%	152.7
Depreciation and amortization	77.5	7.0 %	72.4	3.6%	69.9
Other taxes	37.5	7.8 %	34.8	8.1%	32.2
Operating Income	$ 151.6	(5.0)%	$ 159.5	4.3%	$ 152.9

2015 vs 2014

- Margin increased due to residential and commercial customer growth of $7.8 million partially offset by a decrease of $3.1 million at SCE&G due to a SCPSC-approved decrease in base rates under the RSA effective November 2014.
- Operation and maintenance expenses increased due to higher labor costs, primarily due to incentive compensation.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Margin increased primarily due to residential and commercial customer growth of $9.1 million and increased average usage at SCE&G of $2.5 million.
- Operations and maintenance expense increased $0.9 million due to labor.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2015	Change	2014	Change	2013
Residential	39,090	(15.4)%	46,207	12.0 %	41,268
Commercial	28,064	(8.6)%	30,701	8.9 %	28,181
Industrial	20,101	(1.2)%	20,343	(8.9)%	22,319
Transportation gas	49,297	8.3 %	45,506	7.8 %	42,221
Total	136,552	(4.3)%	142,757	6.5 %	133,989

2015 vs 2014

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use, partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to a shift to transportation service from system supply and the impact of curtailments, partially offset by lower curtailments at PSNC Energy. Transportation volumes increased due to customers shifting to transportation-only service at SCE&G and increased sales for natural gas fired electric generation in PSNC Energy's territory.

2014 vs 2013

Total sales volumes increased primarily due to weather and residential and commercial customer growth. Industrial sales volumes decreased primarily due to weather-related curtailments and a customer switching to an alternative fuel source. Transportation sales increased due to an increase in natural gas fired generation, partially offset by curtailments.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy, which operates in Georgia’s natural gas market. Retail Gas Marketing operating revenues and net income were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 449.2	(12.8)%	$ 514.9	10.7%	$ 465.2
Net Income	18.6	(28.2)%	25.9	8.8%	23.8

Changes in operating revenues are primarily related to the lower price of natural gas and weather-related changes in demand. Changes in net income are primarily due to weather-related changes in demand.

Energy Marketing

Energy Marketing is comprised of the Company’s nonregulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net income were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 697.5	(28.9)%	$ 981.5	19.9 %	$ 818.5
Net Income	9.0	76.5 %	5.1	(16.4)%	6.1

2015 vs 2014

Operating revenues decreased due to lower industrial sales volume and lower market prices. Net income increased due to lower cost of gas and lower costs of transportation to serve customers.

2014 vs 2013

Operating revenues increased due to higher industrial sales volume and higher market prices. Net income decreased due to higher cost to serve customers during periods of pipeline constraints.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars		2015	Change		2014	Change		2013
Other operation and maintenance	$	715.3	(1.8)%	$	728.3	2.9%	$	707.5
Depreciation and amortization		357.5	(6.8)%		383.7	1.5%		378.1
Other taxes		234.2	2.4 %		228.8	4.1%		219.7

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in those discussions. Additional information on a consolidated basis is provided below.

2015 vs 2014

In addition to factors discussed in the electric operations and gas distribution segments, other operation and maintenance expenses decreased by $24.2 million, depreciation and amortization decreased by $7.8 million and other taxes decreased by $8 million due to the sale of CGT.

2014 vs 2013

See discussion in the electric operations and gas distribution segments.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on the Company's income statements and balance sheets as follows:

Millions of dollars		2015	Change		2014	Change		2013
Income Statement Impact:								
Employee benefit costs	$	5.3	6.0%	$	5.0	(67.7)%	$	15.5
Other expense		1.1	*		0.2	(80.0)%		1.0
Balance Sheet Impact:								
Increase in capital expenditures		3.9	*		0.5	(93.1)%		7.2
Component of amount receivable from Summer Station co-owner		1.5	*		0.1	(96.0)%		2.5
Increase (decrease) in regulatory assets		6.2	*		(3.2)	*		5.5
Net periodic benefit cost	$	18.0	*	$	2.6	(91.8)%	$	31.7

* Greater than 100%

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were as follows:

Millions of dollars		2015		2014		2013
Retail electric operations	$	2.0	$	2.0	$	2.0
Gas operations		1.0		1.0		0.2

Other Income (Expense)

Other income (expense) includes the results of certain incidental activities of regulated subsidiaries, the activities of certain non-regulated subsidiaries, and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. Components of other income (expense) were as follows:

Millions of dollars		2015	Change		2014	Change		2013
Other income	$	74.5	(38.8)%	$	121.8	21.4%	$	100.3
Other expense		(60.1)	(6.5)%		(64.3)	41.3%		(45.5)
Gain on sale of SCI, net of transaction costs		106.6	*		—	—		—
AFC - equity funds		27.0	(17.4)%		32.7	23.4%		26.5

* Greater than 100%

2015 vs 2014

Other income decreased due primarily to the recognition of $64.0 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). Other income decreased by $18.3 million and other expenses decreased by $10.9 million due to the sale of SCI. Total other income and other expenses increased by $12.7 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. In 2015 other income also included the gain on the sale of SCI (See Note 13 to the consolidated financial statements). AFC decreased due to lower AFC rates.

2014 vs 2013

Other income (expense) increased primarily due to the recognition of $64.0 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed, compared to $50.1 million of such gains in 2013. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars		2015	Change		2014	Change		2013
Interest on long-term debt, net	$	311.3	1.5%	$	306.7	4.7%	$	292.8
Other interest expense		6.5	14.0%		5.7	23.9%		4.6
Total	$	317.8	1.7%	$	312.4	5.0%	$	297.4

Interest on long-term debt increased in each year primarily due to increased borrowings.

Income Taxes

Income tax expense increased each year primarily due to increases in income before taxes. Income before taxes, income taxes and the effective tax rate were all higher in 2015 primarily due to the sales of CGT and SCI.

LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its contractual cash obligations will be met in 2016 through internally generated funds and additional short- and long-term borrowings. In 2017 and beyond, the Company may also meet such obligations through the sale of equity securities. The Company expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

Due primarily to the availability of proceeds from the sale of two subsidiaries in the first quarter of 2015, the Company began using open market purchases for its stock plans at the end of January 2015. Prior to the use of open market purchases, SCANA common stock was acquired on behalf of participants in SCANA's Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares. This provided additional equity of approximately $14 million in 2015, $98 million in 2014 and $99 million in 2013. In addition, in March 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196 million.

Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of the Company's commonly monitored financial credit metrics could adversely affect the Company's debt ratings. This could cause the Company to pay higher interest rates on its long- and short-term indebtedness, and could limit the Company's access to capital markets and liquidity.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.2 billion in 2015. The Company's current estimates of its capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2016	2017	2018
SCE&G - Normal			
Generation	$ 88	$ 130	$ 91
Transmission & Distribution	192	163	187
Other	12	9	15
Gas	61	63	60
Common	3	2	4
Total SCE&G - Normal	356	367	357
PSNC Energy	198	279	212
Other	27	30	21
Total Normal	581	676	590
New Nuclear (including transmission)	1,166	1,013	677
Cash Requirements for Construction	1,747	1,689	1,267
Nuclear Fuel	122	80	89
Total Estimated Capital Expenditures	$ 1,869	$ 1,769	$ 1,356

The Company's contractual cash obligations as of December 31, 2015 are summarized as follows:

Contractual Cash Obligations	Payments due by periods				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long- and short-term debt, including interest	$ 12,599	$ 958	$ 1,635	$ 1,345	$ 8,661
Capital leases	18	6	9	1	2
Operating leases	59	10	19	6	24
Purchase obligations	4,171	1,950	2,108	112	1
Other commercial commitments	4,273	847	1,776	950	700
Total	$ 21,120	$ 3,771	$ 5,547	$ 2,414	$ 9,388

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at Summer Station. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent. SCE&G estimates it will cost $750 million to $850 million to acquire an additional 5% ownership in the New Units and has included $750 million for this purpose in other commercial commitments. See also New Nuclear Construction in Note 10 to the consolidated financial statements.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary “make-whole” or default provisions, but are not considered to be “take-or-pay” contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a “take-and-pay” contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $10.3 million in 2015, and such annual payments are expected to be the same or increase to as much as $12.3 million in the future.

The Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. The Company is also party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 6 to the consolidated financial statements. At December 31, 2015, the Company had posted $14.3 million in cash collateral for such natural gas futures contracts, and had posted $36.1 million in cash collateral related to interest rate derivative contracts.

In connection with the effectiveness of the October 2015 Amendment, SCE&G accrued within accounts payable $250 million (SCE&G's 55% share is $137.5 million) as of December 31, 2015 for the settlement and release of substantially all outstanding disputes between SCE&G and the Consortium. These amounts are not included in capital expenditures and contractual cash obligations above. See Note 10 to the consolidated financial statements.

The Company has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements. In addition, the Company has recorded liabilities for certain unrecognized tax benefits that are not included in contractual cash obligations above. See Note 5 to the consolidated financial statements.

Financing Limits and Related Matters

The Company’s issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

In December 2015, the Company's existing five-year committed LOCs were amended, extended and, in some cases, upsized. At December 31, 2015 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $400 million, $1.2 billion, of which $500 million relates to Fuel Company, and $200 million, respectively, which expire in December 2020. In addition, at December 31, 2015 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million to ensure sufficient liquidity was available to redeem its Junior Subordinated Notes on February 2, 2015. No borrowings were made under this agreement, and it expired according to its terms on February 6, 2015.

As of December 31, 2015, the Company had no outstanding borrowings under its $2.0 billion credit facilities, had approximately $531 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC supported letters of credit, and held approximately $176 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2015 were approximately $479 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2015, the Company's long-term debt portfolio has a weighted average maturity of approximately 20 years and bears an average cost of 5.8%. Substantially all of the Company's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, the Company rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

The Company's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy's note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015, approximately $72.4 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Financing Activities

During 2015, net cash outflows related to financing activities totaled approximately $360 million, primarily associated with the repayment of long-term and short-term debt and payment of dividends, partially offset by proceeds from the issuance of long-term debt.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.70% junior subordinated notes at their face value.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $253 million, net, in 2015, approximately $95 million in 2014 and approximately $6 million, net, through the third quarter of 2013. During the fourth quarter of 2013, the Company received approximately $120 million upon the settlement of interest rate derivatives.

For additional information, see Note 4 to the consolidated financial statements.

Major tax incentives included within federal legislation resulted in the allowance of bonus depreciation for property placed in service in 2008 through 2015. These incentives, along with certain other deductions, have had a positive impact on the cash flows of the Company. Bonus depreciation will also be significant for 2016 through 2019 under recent law.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2015, were as follows:

December 31,	2015	2014	2013	2012	2011
SCANA	4.40	3.39	3.22	2.93	2.87

The ratio for 2015 reflects the impact of gains recorded upon the sale of certain subsidiaries. See Note 13 to the consolidated financial statements.

NEW NUCLEAR CONSTRUCTION MATTERS

For a discussion of developments related to new nuclear construction, see Note 2 and Note 10 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

For the three years ended December 31, 2015, the Company's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $41.4 million. During this same period, the Company expended approximately $38.5 million for the construction and retirement of landfills and ash ponds, net of disposal proceeds. In addition, the Company made expenditures to operate and maintain environmental control equipment at its fossil plants of $8.7 million in 2015, $9.1 million in 2014 and $9.2 million in 2013, which are included in other operation and maintenance expense, and made expenditures to handle waste ash, net of disposal proceeds, of $1.3 million in 2015, $1.6 million in 2014 and $3.2 million in 2013, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2015, 2014 and 2013 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $15.3 million for 2016 and $88.9 million for the four-year period 2017-2020. These expenditures are included in the Company's Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to the Company's electric system, as well as impacts on employees and customers and on the Company's supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow the Company to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC, under Dodd-Frank, concerning recordkeeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCANA and any of its subsidiaries engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, and other matters; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.

SCE&G and PSNC Energy	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively. The ORS and the NCUC are responsible for enforcement of federal and state pipeline safety requirement in South Carolina (SCE&G) and North Carolina (PSNC Energy), respectively.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system is subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the Company's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Accounting for Rate Regulated Operations

SCANA's regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of the Company's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the Company's regulatory assets and liabilities.

The Company's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, the Company could be required to write down its investment in those assets. The Company cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect the Company's results of operations in the period in which they would be recorded. As of December 31, 2015, the Company's net investments in fossil/hydro and nuclear generation assets were approximately $2.3 billion and $4.1 billion, respectively.

In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could also be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the Company's utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, the Company records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. Accounts receivable included unbilled revenues of $129.1 million at December 31, 2015 and $186.4 million at December 31, 2014, compared to total revenues of $4.4 billion in 2015 and $5.0 billion in 2014.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact the Company's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Asset Retirement Obligations

The Company accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from the acquisition, construction, development and normal operation in accordance with applicable accounting guidance. The Company recognizes obligations at present value in the period in which they are incurred, and capitalizes associated asset retirement costs as a part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to the Company's regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2015, the Company has recorded AROs of $176 million for nuclear plant decommissioning (as discussed above) and AROs of $344 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of imprecision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $18.0 million recorded in 2015 reflects the use of a 4.20% discount rate derived using a cash flow matching technique, and an assumed 7.5% long-term rate of return on plan assets. The Company believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2015 would have increased the Company's pension cost by $1.9 million and increased the pension obligation by $26.8 million. Further, had the assumed long-term rate of return on assets been 7.25%, the Company's pension cost for 2015 would have increased by $2.1 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

The Company determines the fair value of the majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2015, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.0%, 5.4%, 8.7% and 8.8%, respectively. The 2015 expected long-term rate of return of 7.50% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2016, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.3%, 4.6%, 7.2% and 8.7%, respectively. For 2016, the expected rate of return is 7.50%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the significance of pension costs and the criticality of the related estimates to the Company's financial statements will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.30%, derived using a cash flow matching technique, and recorded a net cost of $19.2 million for 2015. Had the selected discount rate been 4.05% (25 basis points lower than the discount rate referenced above), the expense for 2015 would have been $0.8 million higher and increased the obligation by $9.5 million. Because the plan provisions include "caps" on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

OTHER MATTERS

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. SCANA does not engage in significant off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment, airplanes and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provide information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2015	Expected Maturity Date							
Millions of dollars	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	111.5	10.6	719.8	9.1	358.3	4,673.0	5,882.3	6,336.2
Average Fixed Interest Rate (%)	1.16	4.42	6.02	4.73	6.35	5.63	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	129.4	151.4	145.5
Average Variable Interest Rate (%)	1.11	1.11	1.11	1.11	1.11	0.55	0.63	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	654.4	554.4	4.4	4.4	4.4	133.0	1,355.0	(72.1)
Average Pay Interest Rate (%)	2.89	2.91	6.17	6.17	6.17	4.62	3.10	—
Average Receive Interest Rate (%)	0.62	0.62	1.11	1.11	1.11	0.52	0.61	—

December 31, 2014	Expected Maturity Date							
Millions of dollars	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	161.5	110.4	9.5	718.6	8.1	4,529.7	5,537.9	6,437.4
Average Fixed Interest Rate (%)	7.48	1.14	4.62	5.95	4.97	5.29	5.35	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	133.8	155.8	151.2
Average Variable Interest Rate (%)	0.92	0.92	0.92	0.92	0.92	0.48	0.54	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	954.4	104.4	4.4	4.4	4.4	133.8	1,205.8	(256.7)
Average Pay Interest Rate (%)	3.84	3.74	6.17	6.17	6.17	4.70	3.95	—
Average Receive Interest Rate (%)	0.26	0.28	0.92	0.92	0.92	0.47	0.29	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of the Company's long-term debt and interest rate derivatives, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

Commodity Price Risk

The following table provides information about the Company's financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	2016	2017	2018
Futures - Long			
Settlement Price (a)	2.45	2.82	—
Contract Amount (b)	24.4	3.0	—
Fair Value (b)	21.4	2.9	—
Futures - Short			
Settlement Price (a)	2.49	—	—
Contract Amount (b)	1.7	—	—
Fair Value (b)	1.5	—	—
Options - Purchased Call (Long)			
Strike Price (a)	3.31	3.03	—
Contract Amount (b)	23.3	2.5	—
Fair Value (b)	0.5	0.2	—
Swaps - Commodity			
Pay fixed/receive variable (b)	52.1	9.5	4.5
Average pay rate (a)	3.2280	3.6810	3.8753
Average received rate (a)	2.4517	2.8000	2.9235
Fair Value (b)	39.6	7.2	3.4
Pay variable/receive fixed (b)	35.4	7.9	3.2
Average pay rate (a)	2.4705	2.7995	2.9240
Average received rate (a)	3.1645	3.5821	3.9355
Fair Value (b)	45.4	10.1	4.3
Swaps - Basis			
Pay variable/receive variable (b)	3.9	0.7	—
Average pay rate (a)	2.4630	2.8231	—
Average received rate (a)	2.4432	2.8281	—
Fair Value (b)	3.9	0.7	—

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements. The information above includes those financial positions of Energy Marketing and PSNC Energy.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

SCANA Corporation and Subsidiaries
Consolidated Balance Sheets

December 31, (Millions of dollars)	2015	2014
Assets		
Utility Plant In Service	$ 12,883	$ 12,289
Accumulated Depreciation and Amortization	(4,307)	(4,088)
Construction Work in Progress	4,051	3,323
Plant to be Retired, Net	—	169
Nuclear Fuel, Net of Accumulated Amortization	308	329
Goodwill	210	210
Utility Plant, Net	13,145	12,232
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $124 and $122	280	284
Assets held in trust, net-nuclear decommissioning	115	113
Other investments	71	75
Nonutility Property and Investments, Net	466	472
Current Assets:		
Cash and cash equivalents	176	137
Receivables:		
Customer, net of allowance for uncollectible accounts of $5 and $7	505	684
Other	227	154
Inventories:		
Fuel	164	222
Materials and supplies	148	139
Prepayments	115	320
Other current assets	43	148
Assets held for sale	—	341
Total Current Assets	1,378	2,145
Deferred Debits and Other Assets:		
Regulatory assets	1,937	1,823
Other	220	146
Total Deferred Debits and Other Assets	2,157	1,969
Total	$ 17,146	$ 16,818

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2015	2014
Capitalization and Liabilities		
Common Stock - no par value (shares outstanding: December 31, 2015 - 142.9 million; December 31, 2014 - 142.7 million)	$ 2,390	$ 2,378
Retained Earnings	3,118	2,684
Accumulated Other Comprehensive Loss	(65)	(75)
Total Common Equity	5,443	4,987
Long-Term Debt, Net	5,882	5,497
Total Capitalization	11,325	10,484
Current Liabilities:		
Short-term borrowings	531	918
Current portion of long-term debt	116	166
Accounts payable	590	520
Customer deposits and customer prepayments	137	98
Taxes accrued	242	182
Interest accrued	83	83
Dividends declared	76	73
Liabilities held for sale	—	52
Derivative financial instruments	50	233
Other	127	143
Total Current Liabilities	1,952	2,468
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,907	1,931
Asset retirement obligations	520	563
Pension and postretirement benefits	315	315
Regulatory liabilities	855	814
Other	272	243
Total Deferred Credits and Other Liabilities	3,869	3,866
Commitments and Contingencies (Note 10)	—	—
Total	$ 17,146	$ 16,818

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Income

Years Ended December 31, (Millions of dollars, except per share amounts)	2015	2014	2013
Operating Revenues:			
Electric	$ 2,551	$ 2,622	$ 2,423
Gas-regulated	811	1,028	955
Gas-nonregulated	1,018	1,301	1,117
Total Operating Revenues	4,380	4,951	4,495
Operating Expenses:			
Fuel used in electric generation	660	793	745
Purchased power	52	81	43
Gas purchased for resale	1,287	1,729	1,491
Other operation and maintenance	715	728	708
Depreciation and amortization	358	384	378
Other taxes	234	229	220
Total Operating Expenses	3,306	3,944	3,585
Gain on sale of CGT, net of transaction costs	234	—	—
Operating Income	1,308	1,007	910
Other Income (Expense):			
Other income	75	122	100
Other expenses	(60)	(64)	(46)
Gain on sale of SCI, net of transaction costs	107	—	—
Interest charges, net of allowance for borrowed funds used during construction of $15, $16 and $14	(318)	(312)	(297)
Allowance for equity funds used during construction	27	33	27
Total Other Expense	(169)	(221)	(216)
Income Before Income Tax Expense	1,139	786	694
Income Tax Expense	393	248	223
Net Income	$ 746	$ 538	$ 471
Per Common Share Data			
Basic Earnings Per Share of Common Stock	$ 5.22	$ 3.79	$ 3.40
Diluted Earnings Per Share of Common Stock	5.22	3.79	3.39
Weighted Average Common Shares Outstanding (millions)			
Basic	142.9	141.9	138.7
Diluted	142.9	141.9	139.1
Dividends Declared Per Share of Common Stock	$ 2.18	$ 2.10	$ 2.03

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31, (Millions of dollars)	2015	2014	2013
Net Income	$ 746	$ 538	$ 471
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $(7), $(9) and $4	(12)	(14)	7
Gains (losses) on cash flow hedging activities reclassified to interest expense, net of tax of $4, $4 and $5	7	7	8
Gains (losses) on cash flow hedging activities reclassified to gas purchased for resale, net of tax of $9, $(2) and $2	15	(4)	3
Net unrealized gains (losses) on cash flow hedging activities	10	(11)	18
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $-, $(3) and $4	—	(5)	7
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	—	1	1
Net deferred costs of employee benefit plans	—	(4)	8
Other Comprehensive Income (Loss)	10	(15)	26
Total Comprehensive Income	$ 756	$ 523	$ 497

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2015	2014	2013
Cash Flows From Operating Activities:			
Net Income	$ 746	$ 538	$ 471
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain on sale of subsidiaries	(355)	—	—
Losses from equity method investments	3	5	7
Deferred income taxes, net	(31)	235	49
Depreciation and amortization	368	403	393
Amortization of nuclear fuel	46	45	57
Allowance for equity funds used during construction	(27)	(33)	(27)
Carrying cost recovery	(12)	(9)	(3)
Changes in certain assets and liabilities:			
Receivables	188	(33)	(38)
Inventories	(16)	(62)	21
Prepayments	211	(235)	49
Regulatory assets	148	(372)	113
Regulatory liabilities	3	(133)	56
Accounts payable	(78)	36	24
Taxes accrued	61	(24)	42
Pension and other postretirement benefits	(6)	133	(217)
Derivative financial instruments	(183)	225	(72)
Other assets	(21)	(8)	17
Other liabilities	14	19	108
Net Cash Provided From Operating Activities	1,059	730	1,050
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,153)	(1,092)	(1,106)
Proceeds from sale of subsidiaries	647	—	—
Proceeds from investments (including derivative collateral returned)	1,117	347	222
Purchase of investments (including derivative collateral posted)	(1,018)	(475)	(176)
Payments upon interest rate derivative contract settlement	(263)	(95)	(49)
Proceeds from interest rate derivative contract settlement	10	—	163
Net Cash Used For Investing Activities	(660)	(1,315)	(946)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	14	98	295
Proceeds from issuance of long-term debt	491	294	451
Repayments of long-term debt	(166)	(54)	(258)
Dividends	(309)	(294)	(281)
Short-term borrowings, net	(387)	542	(247)
Deferred financing costs	(3)	—	—
Net Cash Provided From (Used For) Financing Activities	(360)	586	(40)
Net Increase in Cash and Cash Equivalents	39	1	64
Cash and Cash Equivalents, January 1	137	136	72
Cash and Cash Equivalents, December 31	$ 176	$ 137	$ 136
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $15, $16 and $14)	$ 306	$ 301	$ 288
—Income taxes	184	299	104
Noncash Investing and Financing Activities:			
Accrued construction expenditures	244	180	111
Capital leases	6	5	6
Nuclear fuel purchase	—	—	98

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Changes in Common Equity

	Common Stock				Accumulated Other Comprehensive Income (Loss)			
Millions	Shares	Outstanding Amount	Treasury Shares	Retained Earnings	Gains (Losses) Cash Flow Hedges	Deferred Employee Benefit Plans	Total AOCI	Total
Balance as of January 1, 2013	132	$ 1,992	$ (9)	$ 2,257	$ (70)	$ (16)	$ (86)	$ 4,154
Net Income				471				471
Other Comprehensive Income (Loss)								
Losses arising during the period					7	7	14	14
Losses/amortization reclassified from AOCI					11	1	12	12
Total Comprehensive Income (Loss)				471	18	8	26	497
Issuance of Common Stock	9	297						297
Dividends Declared				(284)				(284)
Balance as of December 31, 2013	141	2,289	(9)	2,444	(52)	(8)	(60)	4,664
Net Income				538				538
Other Comprehensive Income (Loss)								
Losses arising during the period					(14)	(5)	(19)	(19)
Losses/amortization reclassified from AOCI					3	1	4	4
Total Comprehensive Income (Loss)				538	(11)	(4)	(15)	523
Issuance of Common Stock	2	99	(1)					98
Dividends Declared				(298)				(298)
Balance as of December 31, 2014	143	2,388	(10)	2,684	(63)	(12)	(75)	4,987
Net Income				746				746
Other Comprehensive Income (Loss)								
Losses arising during the period					(12)	—	(12)	(12)
Losses/amortization reclassified from AOCI					22	—	22	22
Total Comprehensive Income (Loss)				746	10	—	10	756
Issuance of Common Stock	—	14	(2)					12
Dividends Declared				(312)				(312)
Balance as of December 31, 2015	143	$ 2,402	$ (12)	$ 3,118	$ (53)	$ (12)	$ (65)	$ 5,443

Dividends declared per share of common stock were $2.18, $2.10 and $2.03 for 2015, 2014 and 2013, respectively.

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina, the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia and conducts other energy-related business.

The accompanying consolidated financial statements reflect the accounts of SCANA, the following wholly-owned subsidiaries, and subsidiaries that formerly were wholly-owned during the periods presented.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	ServiceCare, Inc.
South Carolina Generating Company, Inc.	SCANA Services, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Corporate Security Services, Inc.

CGT and SCI were sold in the first quarter of 2015. Accordingly, the assets and liabilities of these entities are aggregated and shown as Assets held for sale and Liabilities held for sale in the December 31, 2014 consolidated balance sheet. See Note 13.

The Company reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

In April 2015, the FASB issued accounting guidance intended to simplify the presentation of debt issuance costs by requiring that such costs be deducted from carrying amounts related to debt when presented in the balance sheet. As permitted, the Company adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $34 million of unamortized debt issuance costs were reclassified to long-term debt, and certain amounts in Note 4 and Note 12 were also reclassified for comparative periods. The effect of adoption on the Company’s results of operations and cash flows was not significant.

In November 2015, the FASB issued accounting guidance intended to simplify the presentation of deferred tax assets and deferred tax liabilities by netting and classifying them as noncurrent on the statement of financial position. As permitted, the Company early adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $65.5 million of net deferred tax liabilities previously classified in current liabilities were reclassified to long-term liabilities. The effect of adoption on the Company's results of operations and cash flows was not significant.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset’s life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company's regulated subsidiaries calculated AFC using average composite rates of 6.1% for 2015, 7.2% for 2014 and 6.9% for 2013. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

The Company records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. In addition, CGT was sold in the first quarter of 2015 (see Note 13) and excluded from the 2015 calculation of composite weighted average depreciation rates. The composite weighted average depreciation rates for utility plant assets were as follows:

	2015	2014	2013
SCE&G	2.55%	2.85%	2.96%
GENCO	2.66%	2.66%	2.66%
CGT	—	2.11%	2.19%
PSNC Energy	2.94%	2.98%	3.01%
Weighted average of above	2.61%	2.84%	2.93%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2015		2014	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 620.4 million	—	$ 578.3 million	—
Construction work in progress	$ 214.6 million	$ 3.4 billion	$ 199.3 million	$ 2.7 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $178.8 million at December 31, 2015 and $88.9 million at December 31, 2014.

Plant to be Retired

At December 31, 2014, SCE&G expected to retire three units that are or were coal-fired by 2020, which was prior to the end of the previously estimated useful lives over which the units were being depreciated. As such, these units were identified as Plant to be Retired. Subsequently, these units were converted to be gas-fired. In the third quarter of 2015, in connection with the adoption of a customary depreciation study and related analysis (see Note 2), SCE&G determined that these units would not likely be retired by 2020, and their depreciation rates were set to recover the units' net carrying value over their respective revised useful lives. Accordingly, the net carrying value of these units is no longer classified as Plant to be Retired at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2015 and 2014, SCE&G incurred $16.5 million and $19.4 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, effective January 1, 2013, SCE&G accrues $1.4 million per month for its portion of the nuclear refueling outages that are scheduled for the spring of 2014 through the spring of 2020. Total costs for 2014 were $43.7 million, of which SCE&G was responsible for $29.1 million. Total costs for 2015 were $40.2 million, of which SCE&G was responsible for $26.8 million.

Goodwill

The Company considers certain amounts categorized by FERC as “acquisition adjustments” to be goodwill. For each period presented, assets with a carrying value of $210 million (net of a writedown taken in 2002 of $230 million) for PSNC Energy (Gas Distribution segment) were classified as goodwill. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. The goodwill impairment testing is generally a two-step quantitative process which in step one requires estimation of the fair value of the reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Accounting guidance adopted by the Company gives it the option to first perform a qualitative assessment of impairment. Based on this qualitative ("step zero") assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with the two-step quantitative assessment.

In evaluations of PSNC Energy, fair value was estimated using the assistance of an independent appraisal. In evaluations for the periods presented, step one has indicated no impairment, and no impairment charges have been recorded. Should a write-down be required in the future, such a charge would be treated as an operating expense.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each period presented) are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.
Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable.

Asset Management and Supply Service Agreements

PSNC Energy utilizes asset management and supply service agreements with counterparties for certain natural gas storage facilities. Such counterparties held 46% and 48% of PSNC Energy’s natural gas inventory at December 31, 2015 and December 31, 2014, respectively, with a carrying value of $17.7 million and $26.1 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees. No fees are received under supply service agreements. The agreements expire March 31, 2017.

Income Taxes

The Company files consolidated federal income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary’s current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company’s regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Regulatory Assets and Regulatory Liabilities

The Company’s rate-regulated utilities record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or record revenue in a period different from the period in which the revenue would be recorded by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations to be refunded to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as receivables or accounts payable, respectively.

Debt Issuance Premiums, Discounts and Other Costs

The Company presents long-term debt premiums, discounts and debt issuance costs within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

The Company presents the revenues and expenses of its regulated businesses and its retail natural gas marketing businesses (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense). Consistent with this presentation, the gain on the sale of CGT is reflected within operating income and the gain on the sale of SCI is reflected within other income (expense).

Revenue Recognition

The Company records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $129.1 million at December 31, 2015 and $186.4 million at December 31, 2014.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy’s PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. An eWNA for SCE&G's electric customers was discontinued effective with the first billing cycle of 2014 as approved by the SCPSC.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

The Company computes basic earnings per share by dividing net income by the weighted average number of common shares outstanding for the period. The Company computes diluted earnings per share using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method.

The weighted average number of common shares for each period presented for basic and diluted earnings per share purposes were identical, except that for 2013, the net effect of equity forward contracts resulted in such shares for diluted earnings per share purposes being 0.4 million higher than for basic earnings per share purposes.

New Accounting Matters

In April 2014, the FASB issued accounting guidance for reporting discontinued operations and disclosures of disposals of components of an entity. Under this guidance, only those discontinued operations which represent a strategic shift that will have a major effect on an entity’s operations and financial results should be reported as discontinued operations in the financial statements. As permitted, the Company adopted this guidance for the period ended December 31, 2014.

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Company is required to adopt this guidance in the first quarter of 2018 and early adoption is permitted in the first quarter of 2017. Adoption using a retrospective method is required, with options to elect certain practical expedients or to recognize a cumulative effect in the year of initial adoption. The Company has not determined when it will adopt this guidance or what elections it will make. The Company has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other things, the guidance clarifies how to account for a software license element included in a cloud computing arrangement, and makes explicit that a cloud computing arrangement not containing a software license element should be accounted for as a service contract. The Company has determined that this guidance, when adopted in the first quarter of 2016, will not significantly impact the Company's results of operations, cash flows or financial position.

In July 2015, the FASB issued accounting guidance intended to simplify the subsequent measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. The Company expects to adopt this guidance when required in the first quarter of 2017. The Company is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In January 2016, the FASB issued accounting guidance intended to clarify the classification and measurement of financial instruments and financial liabilities, among other things. The Company expects to adopt this guidance when required in the first quarter of 2018. The Company is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over twelve months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily of the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for years beginning in 2019. The Company has not determined what impact this guidance will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to a November 2013 SCPSC accounting order, the Company's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. SCE&G is to make a good faith effort to have at least 30 MW of utility-scale solar capacity in service by the end of 2016.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million ($.12 per share) in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million ($.06 per share) with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, the Company's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

In October 2015, the SCPSC initiated its 2016 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 7, 2016.

Electric - Base Rates

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

Pursuant to an SCPSC order, SCE&G removes from rate base deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $9.5 million and $5.8 million during 2015 and 2014, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G’s request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G’s DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

In January 2016, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would allow recovery of $37.6 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Through 2015, requested rate adjustments have been based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	**Increase**	**Amount**
2015	2.6%	$64.5 million
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million

In September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed. See Note 10.

Gas - SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	**Action**	**Amount**
2015	No change	—
2014	0.6% Decrease	$2.6 million
2013	No change	—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Gas - PSNC Energy

PSNC Energy's Rider D rate mechanism allows it to recover from customers all prudently incurred gas costs and certain related uncollectible expenses as well as losses on negotiated gas and transportation sales.

PSNC Energy establishes rates using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

In October 2015, in connection with PSNC Energy's 2015 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2015.

In May 2014, the NCUC issued an order requiring utilities to adjust rates to reflect changes in the state corporate income tax rate that had been enacted by the North Carolina legislature and to file a proposal to refund amounts previously collected on a provisional basis. Pursuant to the order, PSNC Energy lowered its rates effective July 1, 2014, and refunded the amounts previously collected through the normal operation of its Rider D rate mechanism. These amounts were not significant for any period presented.

Regulatory Assets and Regulatory Liabilities

The Company's cost-based, rate-regulated utilities recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2015**	**2014**
Regulatory Assets:		
Accumulated deferred income taxes	$ 298	$ 284
AROs and related funding	405	366
Deferred employee benefit plan costs	325	350
Deferred losses on interest rate derivatives	535	453
Unrecovered plant	127	137
Environmental remediation costs	42	40
DSM Programs	61	56
Other	144	137
Total Regulatory Assets	$ 1,937	$ 1,823
Regulatory Liabilities:		
Asset removal costs	$ 732	$ 703
Deferred gains on interest rate derivatives	96	82
Other	27	29
Total Regulatory Liabilities	$ 855	$ 814

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to AFC and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G will amortize these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by the Company, and are expected to be recovered over periods of up to approximately 24 years.

DSM Programs represent deferred costs associated with such programs. As a result of the April 2015 SCPSC order, deferred costs are currently being recovered over approximately five years through an approved rate rider.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. COMMON EQUITY

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015 and 2014, retained earnings of approximately $72.4 million and $67.7 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

Authorized shares of common stock were 200 million as of December 31, 2015 and 2014.

SCANA issued common stock valued at $14.3 million, $99.3 million and $100.9 million (when issued) during the years ended December 31, 2015, 2014 and 2013, respectively, to satisfy the requirements of various compensation and dividend reinvestment plans. In addition, in March 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196.2 million.

4. LONG-TERM AND SHORT-TERM DEBT

Total long-term debt, net reflects the retrospective adoption of accounting guidance for unamortized debt issuance costs in the fourth quarter of 2015 (see Note 1). Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2015		2014	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%
SCANA Senior Notes (unsecured) (a)	2016 - 2034	84	1.11%	88	0.93%
SCE&G First Mortgage Bonds (secured)	2018 - 2065	4,340	5.78%	3,840	5.56%
GENCO Notes (secured)	2016 - 2024	220	5.92%	227	5.90%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.51%	122	3.51%
PSNC Senior Debentures	2020 - 2026	350	5.93%	350	5.93%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other (c)	2016 - 2027	18	2.72%	167	7.39%
Total debt		6,034		5,694	
Current maturities of long-term debt		(116)		(166)	
Unamortized premium, net		—		3	
Unamortized debt issuance costs		(36)		(34)	
Total long-term debt, net		$ 5,882		$ 5,497	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%).
(b) Includes variable rate debt of $67.8 million at December 31, 2015 (rate of 0.03%) and 2014 (rate of 0.04%) which are hedged by fixed swaps.
(c) Includes Junior Subordinated Notes redeemed at par prior to maturity on February 2, 2015, and included in the current portion of long-term debt on the balance sheet at December 31, 2014.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Long-term debt maturities will be $116 million in 2016, $15 million in 2017, $724 million in 2018, $13 million in 2019 and $363 million in 2020.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Lines of Credit and Short-Term Borrowings

At December 31, 2015 and 2014, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

	SCANA		SCE&G		PSNC Energy	
Millions of dollars	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Lines of Credit:						
Total committed long-term	$ 400	$ 300	$ 1,400	$ 1,400	$ 200	$ 100
Outstanding commercial paper (270 or fewer days)	$ 37	$ 179	$ 420	$ 709	$ 74	$ 30
Weighted average interest rate	1.19%	0.54%	0.74%	0.52%	0.77%	0.65%
Letters of credit supported by LOC	$ 3	$ 3	$ 0.3	$ 0.3	—	—
Available	$ 360	$ 118	$ 980	$ 691	$ 126	$ 70

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to five-year credit agreements in the amounts of $400 million, $1.2 billion (of which $500 million relates to Fuel Company) and $200 million, respectively. In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In December 2015, the term of the five-year agreements was amended and extended by one year, such that they expire in December 2020. The three-year agreement expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million. SCANA entered this agreement to ensure sufficient liquidity was available to redeem its junior subordinated notes on February 2, 2015. No borrowings were made under this agreement, and it expired according to its terms on February 6, 2015.

The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	**2015**	**2014**	**2013**
Current taxes:			
Federal	$ 382	$ 38	$ 161
State	57	(4)	17
Total current taxes	439	34	178
Deferred tax (benefit) expense, net:			
Federal	(36)	184	39
State	(7)	34	10
Total deferred taxes	(43)	218	49
Investment tax credits:			
Amortization of amounts deferred-state	(1)	(1)	(1)
Amortization of amounts deferred-federal	(2)	(3)	(3)
Total investment tax credits	(3)	(4)	(4)
Total income tax expense	$ 393	$ 248	$ 223

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2015	2014	2013
Net income	$ 746	$ 538	$ 471
Income tax expense	393	248	223
Total pre-tax income	$ 1,139	$ 786	$ 694
Income taxes on above at statutory federal income tax rate	$ 399	$ 275	$ 243
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	38	24	22
State investment tax credits (less federal income tax effect)	(6)	(5)	(5)
Allowance for equity funds used during construction	(9)	(11)	(9)
Deductible dividends—401(k) Retirement Savings Plan	(10)	(10)	(10)
Amortization of federal investment tax credits	(2)	(3)	(3)
Section 41 tax credits	1	(3)	—
Section 45 tax credits	(9)	(9)	(5)
Domestic production activities deduction	(18)	(7)	(11)
Realization of basis differences upon sale of subsidiaries	7	—	—
Other differences, net	2	(3)	1
Total income tax expense	$ 393	$ 248	$ 223

The tax effects of significant temporary differences comprising the Company’s net deferred tax liability are as follows:

Millions of dollars	2015	2014
Deferred tax assets:		
Nondeductible accruals	$ 135	$ 127
Asset retirement obligation, including nuclear decommissioning	199	216
Financial instruments	35	40
Unamortized investment tax credits	16	17
Deferred fuel costs	8	—
Monetization of bankruptcy claim	—	10
Other	5	10
Total deferred tax assets	398	420
Deferred tax liabilities:		
Property, plant and equipment	$ 1,906	$ 1,928
Deferred employee benefit plan costs	96	107
Regulatory asset, asset retirement obligation	135	122
Deferred fuel costs	—	27
Regulatory asset, unrecovered plant	49	53
Regulatory asset, net loss on interest rate derivative contracts settlement	—	21
Demand side management costs	23	21
Prepayments	31	27
Other	65	45
Total deferred tax liabilities	2,305	2,351
Net deferred tax liability	$ 1,907	$ 1,931

During the third quarter of 2013, the State of North Carolina passed legislation that lowered the state corporate income tax rate from 6.9% to 6.0% in 2014, 5.0% in 2015 and 4.0% in 2016. In connection with this change in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The change in income tax rates did not and is not expected to have a material impact on the Company’s financial position, results of operations or cash flows.

The Company files consolidated federal income tax returns, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company’s federal returns through 2004, and the Company’s federal returns through 2007 are closed for additional assessment. The IRS is currently examining

SCANA's open federal returns through 2014 as a result of claims discussed below in Changes to Unrecognized Tax Benefits. With few exceptions, the Company is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	2015	2014	2013
Unrecognized tax benefits, January 1	$ 16	$ 3	—
Gross increases—uncertain tax positions in prior period	33	—	—
Gross decreases—uncertain tax positions in prior period	(2)	—	—
Gross increases—current period uncertain tax positions	2	13	$ 3
Unrecognized tax benefits, December 31	$ 49	$ 16	$ 3

During 2013 and 2014, the Company amended certain of its tax returns to claim certain tax-defined research and development deductions and credits and its related impact on domestic production activities. The Company also made similar claims in filing its 2013 and 2014 returns in 2014 and 2015, respectively. In connection with these federal and state filings, the Company recorded an unrecognized tax benefit of $49 million. During 2015, as the IRS' examination of these claims progressed, without resolution, the Company evaluated and recorded adjustments to its unrecognized tax benefits; however, none of these changes materially affected the Company's effective tax rate. If recognized, $17 million of the tax benefits would affect the Company's effective tax rate. It is reasonably possible that these tax benefits will increase by an additional $7 million within the next 12 months. It is also reasonably possible that these tax benefits may decrease by $8 million within the next 12 months. No other material changes in the status of the Company’s tax positions have occurred through December 31, 2015.

The Company recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit, the Company has not recorded a material amount of interest income, interest expense, or penalties associated with any uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. The Company recognizes changes in the fair value of derivative instruments either in earnings, as a component of other comprehensive income (loss) or, for regulated subsidiaries, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA’s Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Company’s Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statement of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and swaps and NYMEX futures and options. PSNC Energy’s tariffs also include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SEMI, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

The Company may use interest rate swaps to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which the Company synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, the Company may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For the holding company or nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, in 2013 the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income in 2013, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G's DSM Program rider, and to apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)			
Hedge designation	**Gas Distribution**	**Retail Gas Marketing**	**Energy Marketing**	**Total**
As of December 31, 2015				
Commodity	7,530,000	7,869,000	3,973,500	19,372,500
Energy Management (a)	—	—	38,857,480	38,857,480
Total (a)	7,530,000	7,869,000	42,830,980	58,229,980
As of December 31, 2014				
Commodity	6,840,000	7,951,000	3,446,720	18,237,720
Energy Management (b)	—	—	37,495,339	37,495,339
Total (b)	6,840,000	7,951,000	40,942,059	55,733,059

(a) Includes an aggregate 1,842,048 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 933,893 MMBTU related to basis swap contracts in Energy Marketing.

The Company was party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $120.0 million at December 31, 2015 and $124.4 million at December 31, 2014. The Company was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.235 billion and $1.085 billion at December 31, 2015 and 2014, respectively.

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments

Millions of dollars	Balance Sheet Location	Asset	Liability
As of December 31, 2015			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 4
	Other deferred credits and other liabilities		28
Commodity contracts	Other current assets		1
	Derivative financial instruments		4
Total			$ 37
Not designated as hedging instruments			
Interest rate contracts	Other current assets	$ 10	
	Other deferred debits and other assets	5	
	Derivative financial instruments		$ 33
	Other deferred credits and other liabilities		22
Commodity contracts	Other current assets	1	
Energy management contracts	Other current assets	11	2
	Other deferred debits and other assets	3	
	Derivative financial instruments		9
	Other deferred credits and other liabilities		3
Total		$ 30	$ 69
As of December 31, 2014			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 5
	Other deferred credits and other liabilities		28
Commodity contracts	Other current assets		1
	Derivative financial instruments		11
Total			$ 45
Not designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 207
	Other deferred credits and other liabilities		17
Commodity contracts	Other current assets	$ 1	
Energy management contracts	Other current assets	15	5
	Other deferred debits and other assets	5	
	Derivative financial instruments		10
	Other deferred credits and other liabilities		5
Total		$ 21	$ 244

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)	Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)
Year Ended December 31, 2013			
Interest rate contracts	$ 106	Interest expense	$ (3)

Millions of dollars	Gain or (Loss) Recognized in OCI, net of tax (Effective Portion)	Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion) Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (2)	Interest expense	$ (7)
Commodity contracts	(10)	Gas purchased for resale	(15)
Total	$ (12)		$ (22)
Year Ended December 31, 2014			
Interest rate contracts	$ (6)	Interest expense	$ (7)
Commodity contracts	(8)	Gas purchased for resale	4
Total	$ (14)		$ (3)
Year Ended December 31, 2013			
Interest rate contracts	$ 5	Interest expense	$ (8)
Commodity contracts	2	Gas purchased for resale	(3)
Total	$ 7		$ (11)

As of December 31, 2015, the Company expects that during the next 12 months reclassifications from accumulated other comprehensive loss to earnings arising from cash flow hedges will include approximately $3.3 million as an increase to gas cost and approximately $7.1 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2015, all of the Company's commodity cash flow hedges settle by their terms before the end of the second quarter of 2018.

As of December 31, 2015, the Company expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.2 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gain (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

Millions of dollars	Gain (Loss) Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64
Year Ended December 31, 2013			
Interest rate contracts	$ 39	Other income	$ 50

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2015, the Company expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $0.6 million as an increase to interest expense.

Credit Risk Considerations

The Company limits credit risk in its commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, the Company uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. The Company uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with the Company's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of the Company’s derivative instruments contain contingent provisions that require the Company to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2015 and 2014, the Company had posted $50.4 million and $152.4 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months is recorded in Other Current Assets on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and 2014, the Company would have been required to post an additional $44.8 million and $129.8 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2015 and 2014, are $95.2 million and $282.2 million, respectively.

In addition, as of December 31, 2015 and December 31, 2014, the Company has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and December 31, 2014, the Company could request $7.3 million and $- million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2015 and December 31, 2014 is $7.3 million and $- million, respectively. In addition, at December 31, 2015, the Company could have called on letters of credit in the amount of $3.0 million related to $14.0 million in commodity derivatives that are in a net asset position, compared to letters of credit of $9.2 million related to derivatives of $20 million at December 31, 2014, if all the contingent features underlying these instruments had been fully triggered.

Information related to the Company's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2015						
Interest rate	$ 15	—	$ 15	$ (8)	—	$ 7
Commodity	1	—	1	—	—	1
Energy Management	15	$ (1)	14	—	—	14
Total	$ 31	$ (1)	$ 30	$ (8)	—	$ 22

Balance sheet location	Other current assets	$ 22
	Other deferred debits and other assets	8
	Total	$ 30

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2014						
Commodity	$ 1	—	$ 1	—	—	$ 1
Energy Management	20	—	20	—	—	20
Total	$ 21	—	$ 21	—	—	$ 21

Balance sheet location	Other current assets	$ 16
	Other deferred debits and other assets	5
	Total	$ 21

Offsetting Derivative Liabilities

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2015						
Interest rate	$ 87	—	$ 87	$ (8)	$ (36)	$ 43
Commodity	5	—	5	—	(5)	—
Energy Management	15	$ (1)	14	—	(9)	5
Total	$ 107	$ (1)	$ 106	$ (8)	$ (50)	$ 48

Balance sheet location	Other current assets	$ 3
	Derivative financial instruments	50
	Other deferred credits and other liabilities	53
	Total	$ 106

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Posted	Net Amount
As of December 31, 2014						
Interest rate	$ 257	—	$ 257	—	$ (131)	$ 126
Commodity	12	—	12	—	(10)	2
Energy Management	20	—	20	—	(11)	9
Total	$ 289	—	$ 289	—	$ (152)	$ 137

Balance sheet location	Other current assets	$ 6
	Derivative financial instruments	233
	Other deferred credits and other liabilities	50
	Total	$ 289

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

The Company values available for sale securities using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. The Company's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Level 1**	**Level 2**	**Level 1**	**Level 2**
Assets:				
Available for sale securities	$ 11	—	$ 13	—
Interest rate contracts	—	$ 15	—	—
Commodity contracts	1	—	1	—
Energy management contracts	—	14	—	$ 20
Liabilities:				
Interest rate contracts	—	87	—	257
Commodity contracts	1	4	1	11
Energy management contracts	4	12	5	18

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2015 and December 31, 2014 were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 5,997.6	$ 6,445.7	$ 5,663.1	$ 6,558.0

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

The Company sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. The Company's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The Company's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, the Company provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2015**	**2014**	**2015**	**2014**
Benefit obligation, January 1	$ 919.5	$ 823.0	$ 268.2	$ 238.0
Service cost	24.1	20.0	5.3	4.6
Interest cost	38.2	40.4	11.4	12.0
Plan participants' contributions	—	—	2.4	2.2
Actuarial (gain) loss	(62.4)	100.1	(21.2)	23.5
Benefits paid	(64.0)	(64.0)	(12.5)	(12.1)
Benefit obligation, December 31	$ 855.4	$ 919.5	$ 253.6	$ 268.2

The Company adopted new mortality tables and an improvement scale published by the Society of Actuaries in 2014, resulting in an actuarial loss for pension and other post retirement benefit obligations of approximately $26.3 million and $2.7 million, respectively, in 2014. In 2015, based on an evaluation of the mortality experience of the pension plan, the Company adopted a custom mortality table for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $21.5 million and $2.4 million, respectively, in 2015.

The accumulated benefit obligation for pension benefits was $829.3 million at the end of 2015 and $888.3 million at the end of 2014. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	**2014**	**2015**	**2014**
Annual discount rate used to determine benefit obligation	4.68%	4.20%	4.78%	4.30%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.8 million at December 31, 2015 and by $1.3 million at December 31, 2014. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.7 million at December 31, 2015 and by $1.0 million at December 31, 2014.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	**2015**	**2014**	**2015**	**2014**
Fair value of plan assets	$ 781.7	$ 861.8	—	—
Benefit obligation	855.4	919.5	$ 253.6	$ 268.2
Funded status	$ (73.7)	$ (57.7)	$ (253.6)	$ (268.2)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Current liability	—	—	$ (11.9)	$ (11.2)
Noncurrent liability	$ (73.7)	$ (57.7)	(241.7)	(257.0)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 10.4	$ 8.1	$ 1.7	$ 3.0
Prior service cost	0.2	0.3	—	0.1
Total	$ 10.6	$ 8.4	$ 1.7	$ 3.1

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 219.4	$ 222.1	$ 24.0	$ 43.8
Prior service cost	5.9	9.6	0.3	0.6
Total	$ 225.3	$ 231.7	$ 24.3	$ 44.4

In connection with the joint ownership of Summer Station, as of December 31, 2015 and 2014, the Company recorded within deferred debits $20.3 million and $17.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2015 and 2014, the Company also recorded within deferred debits $13.8 million and $15.1 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2015	2014
Fair value of plan assets, January 1	$ 861.8	$ 870.0
Actual return (loss) on plan assets	(16.1)	55.8
Benefits paid	(64.0)	(64.0)
Fair value of plan assets, December 31	$ 781.7	$ 861.8

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. During 2013, in connection with the amendments to the plan, the Company adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The Company's pension plan asset allocation at December 31, 2015 and 2014 and the target allocation for 2016 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	2016	2015	2014
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	34%
Hedge Funds	9%	11%	9%

For 2016, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2015 and 2014, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using					
Millions of dollars	Total	Level 2	Level 3	Total	Level 2	Level 3
	December 31, 2015			*December 31, 2014*		
Mutual funds	$ 538	$ 538	—	$ 622	$ 622	—
Short-term investment vehicles	14	14	—	20	20	—
US Treasury securities	22	22	—	6	6	—
Corporate debt securities	78	78	—	86	86	—
Municipals	14	14	—	15	15	—
Limited partnerships	33	33	—	32	32	—
Multi-strategy hedge funds	83	—	$ 83	81	—	$ 81
	$ 782	$ 699	$ 83	$ 862	$ 781	$ 81

At December 31, 2015, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2015 or 2014.

The pension plan values certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

Millions of dollars	Fair Value Measurements Level 3 2015	2014
Beginning Balance	$ 81	$ 76
Unrealized gains included in changes in net assets	2	5
Purchases, issuances, and settlements	—	—
Ending Balance	$ 83	$ 81

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from the Company's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2016	$ 65.1	$ 11.9
2017	63.2	12.7
2018	64.7	13.5
2019	65.3	14.2
2020	65.8	14.9
2021-2025	338.3	80.5

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, the Company does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

The Company records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Service cost	$ 24.1	$ 20.0	$ 21.8	$ 5.3	$ 4.6	$ 5.9
Interest cost	38.2	40.4	38.5	11.4	12.0	11.1
Expected return on assets	(62.0)	(66.7)	(61.4)	n/a	n/a	n/a
Prior service cost amortization	4.1	4.1	6.0	0.4	0.3	0.7
Amortization of actuarial losses	13.6	4.8	16.9	2.1	—	3.3
Transition obligation amortization	—	—	—	—	—	0.3
Curtailment	—	—	9.9	—	—	—
Net periodic benefit cost	$ 18.0	$ 2.6	$ 31.7	$ 19.2	$ 16.9	$ 21.3

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current year actuarial (gain) loss	$ 2.7	$ 3.1	$ (5.0)	$ (1.2)	$ 1.3	$ (1.8)
Amortization of actuarial losses	(0.4)	(0.2)	(0.5)	(0.1)	—	(0.2)
Amortization of prior service cost	(0.1)	(0.2)	(0.2)	(0.1)	—	—
Prior service cost (credit)	—	—	(0.3)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.1)
Total recognized in OCI	$ 2.2	$ 2.7	$ (6.0)	$ (1.4)	$ 1.3	$ (2.1)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current year actuarial (gain) loss	$ 9.2	$ 101.3	$ (157.5)	$ (18.0)	$ 19.4	$ (29.9)
Amortization of actuarial losses	(11.9)	(4.0)	(14.7)	(1.8)	—	(2.7)
Amortization of prior service cost	(3.7)	(3.2)	(5.2)	(0.3)	(0.3)	(0.6)
Prior service cost (credit)	—	—	(8.9)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.2)
Total recognized in regulatory assets	$ (6.4)	$ 94.1	$ (186.3)	$ (20.1)	$ 19.1	$ (33.4)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Discount rate	4.20%	5.03%	4.10%/5.07%	4.30%	5.19%	4.19%
Expected return on plan assets	7.50%	8.00%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.75%/3.00%	3.00%	3.75%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.40%	7.80%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013 was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 0.6	—
Prior service cost	0.2	—
Total	$ 0.8	—

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 12.7	$ 0.3
Prior service cost	3.4	0.3
Total	$ 16.1	$ 0.6

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

The Company sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. The Company provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan were $26.2 million in 2015, $25.8 million in 2014 and $23.4 million in 2013 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2013-2015 and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 award is based on performance over a single three-year cycle. In each performance cycle of the 2013-2015 and 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash and 80% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For the 2015-2017 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2013-2015 performance cycle were paid in cash totaling $18.4 million at SCANA's discretion in February 2016. Cash-settled liabilities related to earlier performance cycles totaled approximately $20.8 million in 2015, $11.8 million in 2014, and $12.2 million in 2013.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $18.0 million in 2015, $20.3 million in 2014 and $8.7 million in 2013. Such fair value adjustments also resulted in capitalized compensation costs of $2.3 million in 2015, $3.1 million in 2014 and $1.4 million in 2013. At December 31, 2015, SCANA had $20.4 million of unrecognized compensation cost, which is expected to be recognized over a weighted-average period of 18 months.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Company's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2015, SCE&G's investment in the New Units, including related transmission, totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In October 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule. Shield building construction remains a principal focus area for SCE&G's oversight of the project. The primary critical path for both Unit 2 and Unit 3 runs through the placement of concrete within the containment vessels, the fabrication of shield building panels, the fabrication of the air inlet and tension rings and the completion of shield building construction. For Unit 3, the critical path also runs through the setting of CA20 which is a prerequisite to concrete placement in certain areas of the nuclear island. Plans to accelerate the work needed to permit placing this concrete are underway. In addition, WEC has reached agreement on a mitigation plan to accelerate shield building panel fabrication with one of its subcontractors. Additional mitigation will be required in critical path areas to support the updated substantial completion dates described below.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The result was a revised fully integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is received.

In September 2015, the SCPSC approved an updated BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively, each subject to an 18-month contingency period. In addition, the SCPSC approved certain updated owner's costs ($245 million) and other capital costs ($453 million), of which $539 million were associated with the schedule delays and other contested costs. In this proceeding, SCE&G's total projected capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) were estimated to be $5.2 billion and $6.8 billion, respectively. These projections included cost amounts related to the Revised, Fully-Integrated Construction Schedule for which SCE&G had not accepted responsibility and which were the subject of dispute. As such, these updated milestone schedule and projections did not reflect the resolution of negotiations. In addition, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding the above mentioned disputes, and the EPC Contract was amended. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor Corporation as a subcontracted construction manager.

Among other things, the October 2015 Amendment:

(i) resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium, in exchange for (a) an additional cost to be paid by SCE&G and Santee Cooper of $300 million (SCE&G’s 55% portion being $165 million) and an increase in the fixed component of the contract price by that amount, and (b) a credit to SCE&G and Santee Cooper of $50 million (SCE&G’s 55% portion being approximately $27 million) to be applied to the target component of the contract price,

(ii) revised the guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), and capped those aggregate liquidated damages at $463 million per New Unit (SCE&G’s 55% portion being approximately $255 million per New Unit),

(iv) provides for payment to the Consortium of a completion bonus of $275 million per New Unit (SCE&G’s 55% portion being approximately $151 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provides for development of a revised construction milestone payment schedule, with SCE&G and Santee Cooper making monthly payments of $100 million (SCE&G’s 55% portion being $55 million) for each of the first five months following effectiveness, followed by payments made based on milestones achieved, and

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project.

Under the October 2015 Amendment, SCE&G’s total estimated project costs increased by approximately $286 million over the $6.8 billion approved by the SCPSC in September 2015, bringing its total estimated gross construction cost of the project (including escalation and AFC) to approximately $7.1 billion.

The payment obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba Corporation, WEC’s parent company, reaffirmed its guaranty of WEC’s payment obligations. Based on Toshiba's current credit ratings and pursuant to the terms of the EPC Contract, SCE&G has exercised its rights to demand a payment and performance bond from WEC. Such bond will be based on estimated billings and its aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bond. In addition, the EPC Contract provides that upon the request of

SCE&G, the Consortium must escrow certain intellectual property and software for SCE&G's benefit to enable completion of the New Units. SCE&G has made such a request to the Consortium.

In addition to the above, the October 2015 Amendment provided for an explicit definition of a Change in Law designed to reduce the likelihood of certain future commercial disputes, and the Consortium also acknowledged and agreed that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19. The October 2015 Amendment also established a dispute resolution board process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction milestone payment schedule referred to above. The EPC Contract was also revised to eliminate the requirement or ability to bring suit before substantial completion of the project.

Finally, the October 2015 Amendment provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G’s 55% portion being approximately $3.345 billion). This total amount to be paid would be subject to adjustment for amounts paid since June 30, 2015. Were this fixed price option to be exercised, the aggregate delay-related liquidated damages referred to in (iii) above would be capped at $338 million per unit (SCE&G’s 55% portion being approximately $186 million per unit), and the completion bonus referred to in (iv) above would be $150 million per New Unit (SCE&G’s 55% portion being approximately $83 million per New Unit). The exercise of this fixed price option would result in SCE&G’s total estimated project costs increasing by approximately $774 million over the $6.8 billion approved by the SCPSC in September 2015, and would bring its total estimated gross construction cost (including escalation and AFC) of the project to approximately $7.6 billion.

Resolution of the disputes as described in (i) above, or in the case of the exercise of the fixed price option, would result in estimated project costs above the amounts approved by the SCPSC; however, the guaranteed substantial completion dates fall within the SCPSC approved 18-month contingency periods. SCE&G held an allowable ex parte communication briefing with the SCPSC on November 19, 2015 and, following an evaluation as to whether to exercise the fixed price option, expects to file a petition in 2016, as provided under the BLRA, for an update to the project’s estimated capital cost and milestone schedule which would incorporate the impact of the October 2015 Amendment.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes through both the informal and formal procedures and currently anticipates that any costs that arise through such dispute resolution processes (including those reflected in the October 2015 Amendment described above), as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the October 2015 Amendment, which has not been approved by the SCPSC, SCE&G’s currently projected cost would be approximately $750 million to $850 million for the additional 5% interest being acquired from Santee Cooper.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on the guaranteed substantial completion dates provided above, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per MWh and new natural gas units to meet 1,000 pounds carbon dioxide per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. The Company is currently evaluating the rule and expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, which delayed the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The Court of Appeals remanded CSAPR, without vacating the rule, to the

EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G and GENCO or their generation operations. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision to retire certain coal-fired units (see Note 2) and its project to build the New Units along with other actions are expected to result in the Company's compliance with MATS.

On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities under the MATS rule. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants. On June 29, 2015, the U.S. Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of Appeals. The Court noted during remand that EPA has said that it is on track to issue a revised "appropriate and necessary" finding by April 15, 2016. The ruling, however, is not expected to have an impact on SCE&G or GENCO due to the aforementioned retirements and conversions. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. The Company expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On April 17, 2015, the EPA's final rule for CCR was published in the Federal Register and became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. Although the full effects of this rule are still being evaluated, SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. The Company does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2015, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and has constructed a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2017 and will cost an additional $18.5 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2015, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $34.8 million and are included in regulatory assets.

Claims and Litigation

The Company is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on the Company's results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company is obligated under various operating leases for rail cars, vehicles, office space, furniture and equipment. Leases expire at various dates through 2051. Rent expense totaled approximately $11.1 million in 2015, $12.3 million in 2014 and $14.8 million in 2013. Future minimum rental payments under such leases will be $10 million in 2016, $7 million in 2017, $6 million in 2018, $6 million in 2019, $3 million in 2020 and $27 million thereafter.

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2015, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.8 billion.

Asset Retirement Obligations

The Company recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that results from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2015, the Company has recorded AROs of approximately $176 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $344 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	2015	2014
Beginning balance	$ 563	$ 576
Liabilities incurred	—	3
Liabilities settled	(16)	(6)
Accretion expense	25	26
Revisions in estimated cash flows	(52)	(36)
Ending balance	$ 520	$ 563

In 2015, revisions in estimated cash flows primarily relate to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study. In 2014 such revisions primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

The Company received cash distributions from equity-method investees of $4.0 million in 2015, $7.8 million in 2014 and $10.4 million in 2013. The Company made investments in equity-method investees of $4.1 million in 2015, $5.7 million in 2014 and $5.2 million in 2013.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G’s total purchases from this affiliate were $233.2 million in 2015, $260.3 million in 2014 and $134.2 million in 2013. SCE&G’s total sales to this affiliate were $232.0 million in 2015, $259.0 million in 2014 and $133.6 million in 2013. SCE&G’s payable to this affiliate was $12.9 million at December 31, 2015 and $27.9 million at December 31, 2014 SCE&G’s receivable from this affiliate was $12.8 million at December 31, 2015 and $27.8 million at December 31, 2014.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein. The Company records intersegment sales and transfers of electricity and gas based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC.

Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively.

Retail Gas Marketing markets natural gas in Georgia and is regulated as a marketer by the GPSC. Energy Marketing markets natural gas to industrial and large commercial customers and municipalities in the Southeast.

All Other is comprised of the holding company and its other direct and indirect wholly-owned subsidiaries, which conduct nonregulated, energy-related operations. All Other also includes two additional subsidiaries prior to their sale in the first quarter of 2015 (see Note 13) and, in 2015, also includes within net income the holding company's gains on the sales of those businesses. None of these subsidiaries met the quantitative thresholds for determining reportable segments during any period reported.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations’ product differs from the other segments, as does its generation process and method of distribution. Marketing segments differ from each other in their respective markets and customer type.

Management uses operating income to measure segment profitability for SCE&G and other regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, the Company does not allocate interest charges, income tax expense or assets other than utility plant to its segments. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Interest income is not reported by segment and is not material. The Company's deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of the Company's regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the totals from SCANA or SCE&G that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Retail Gas Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2015							
External Revenue	$ 2,551	$ 810	$ 449	$ 569	$ 5	$ (4)	$ 4,380
Intersegment Revenue	6	2	—	128	413	(549)	—
Operating Income	876	152	n/a	n/a	236	44	1,308
Interest Expense	17	23	1	—	1	276	318
Depreciation and Amortization	277	77	2	—	16	(14)	358
Income Tax Expense	9	32	12	6	1	333	393
Net Income	n/a	n/a	19	9	185	533	746
Segment Assets	10,883	2,606	106	95	998	2,458	17,146
Expenditures for Assets	1,087	203	—	2	15	(154)	1,153
Deferred Tax Assets	5	29	9	6	—	(49)	—
2014							
External Revenue	$ 2,622	$ 1,012	$ 515	$ 786	$ 37	$ (21)	$ 4,951
Intersegment Revenue	7	2	—	196	437	(642)	—
Operating Income	768	159	n/a	n/a	27	53	1,007
Interest Expense	19	22	1	—	5	265	312
Depreciation and Amortization	300	72	2	—	24	(14)	384
Income Tax Expense	7	33	16	3	12	177	248
Net Income (Loss)	n/a	n/a	26	5	(6)	513	538
Segment Assets	10,182	2,487	140	150	1,474	2,385	16,818
Expenditures for Assets	936	200	—	2	52	(98)	1,092
Deferred Tax Assets	11	29	11	9	15	(75)	—
2013							
External Revenue	$ 2,423	$ 942	$ 465	$ 652	$ 40	$ (27)	$ 4,495
Intersegment Revenue	6	1	—	167	416	(590)	—
Operating Income	679	153	n/a	n/a	27	51	910
Interest Expense	19	22	1	—	4	251	297
Depreciation and Amortization	297	70	3	—	26	(18)	378
Income Tax Expense	6	33	15	4	14	151	223
Net Income (Loss)	n/a	n/a	24	6	(2)	443	471
Segment Assets	9,488	2,340	172	133	1,378	1,616	15,127
Expenditures for Assets	907	140	—	1	31	27	1,106
Deferred Tax Assets	10	27	8	2	14	(61)	—

13. DISPOSITIONS

In December 2014, SCANA entered into definitive agreements to sell CGT and SCI. CGT was an interstate natural gas pipeline regulated by FERC that transported natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provided fiber optic communications and other services and built, managed and leased communications towers in several southeastern states, and it was sold to Spirit Communications. These sales closed in the first quarter of 2015. Proceeds from these sales, net of transaction costs, were approximately $647 million, and the pre-tax gain on the sales recognized during 2015 was approximately $341 million.

CGT and SCI operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment. Accordingly, segment disclosures related to them are included within All Other in Note 12. As a result, the Company determined that the sales of CGT and SCI did not represent a strategic shift that had a major effect on its operations, and therefore, these sales did not meet the criteria for classification as discontinued operations.

The carrying values of the major classes of assets and liabilities classified as held for sale in the consolidated balance sheet as of December 31, 2014, were as follows:

Millions of dollars	CGT	SCI	Total
Assets Held for Sale			
Utility Plant, Net	$ 288.4	—	$ 288.4
Nonutility Property and Investments, Net	0.6	$ 40.1	40.7
Current Assets	6.5	3.9	10.4
Deferred Debits and Other Assets	0.9	0.2	1.1
Total Assets Held for Sale	$ 296.4	$ 44.2	$ 340.6
Liabilities Held for Sale			
Current Liabilities	$ 3.5	$ 2.2	$ 5.7
Deferred Credits and Other Liabilities	42.9	3.1	46.0
Total Liabilities Held for Sale	$ 46.4	$ 5.3	$ 51.7

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2015					
Total operating revenues	$ 1,389	$ 967	$ 1,068	$ 956	$ 4,380
Operating income	586	216	292	214	1,308
Net income	400	99	149	98	746
Earnings per share	2.80	.69	1.04	.69	5.22
2014					
Total operating revenues	$ 1,590	$ 1,026	$ 1,121	$ 1,214	$ 4,951
Operating income	350	154	269	234	1,007
Net income	193	96	144	105	538
Earnings per share	1.37	.68	1.01	.73	3.79

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCE&G is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, and transportation of natural gas. SCE&G's business is subject to seasonal fluctuations. Generally, sales of electricity are higher during the summer and winter months because of air-conditioning and heating requirements, and sales of natural gas are greater in the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 36 counties in South Carolina and covers approximately 23,000 square miles.

Key Earnings Drivers and Outlook

During 2015, economic growth continued to improve in the southeast. In SCE&G's service territory, companies announced plans during the year to invest over $1.6 billion, with the expectation of creating approximately 4,000 jobs. South Carolina's unemployment rate ended December 2015 at 5.5%, a drop of 1% over 2014, an improvement that takes on greater significance when considering that almost 80,000 more South Carolinians were employed at the end of 2015 over 2014. In addition, SCE&G's regulated businesses experienced positive customer growth year over year.

Over the next five years, key earnings drivers for SCE&G will be additions to utility rate base, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generates electricity and provides for its transmission, distribution and sale to approximately 698,000 customers (as of December 31, 2015) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity against other energy sources.

Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2015 was 10.25% for non-BLRA rate base and 11.0% for BLRA-related rate base. To prevent the need for a non-BLRA base rate increase during years of peak nuclear construction, SCE&G has a stated goal of earning a return on equity for non-BLRA rate base of 9% or higher. For the year ended December 31, 2015, SCE&G's earned return on equity related to non-BLRA rate base was approximately 9.75%.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and SCE&G has agreed to acquire an additional 5% ownership from Santee Cooper in increments beginning with the commercial operation date of Unit 2. The purchase of this additional 5% ownership is expected to be funded by increased cash flows resulting from tax deductibility of depreciation associated with the New Units when they enter commercial operation.

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. As of December 31, 2015, SCE&G's investment in the New Units totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

In September 2015, the SCPSC approved an updated BLRA milestone schedule and certain updated owner's costs and other capital costs, some of which were associated with schedule delays and other contested costs. Also in September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%, to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding certain disputes, and the EPC Contract was amended. The October 2015 Amendment became effective on December 31, 2015, and among other things, it resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium. The October 2015 Amendment also provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project after June 30, 2015, subject to certain exceptions.

On November 19, 2015, SCE&G held an allowable *ex parte* communication briefing with the SCPSC to describe SCE&G's settlement with the Consortium. During that briefing, the Company provided the following summary of key points related to the SCPSC's September 2015 order and the October 2015 Amendment.

	SCPSC Order #2015-661 September 2015	**October 2015 Amendment**	**Fixed Price Option Under the October 2015 Amendment**
Guaranteed Substantial Completion Dates	Unit 2 - June 2019 Unit 3 - June 2020	Unit 2 - August 2019 Unit 3 - August 2020	
Capital Cost (SCE&G's 55% share)	$5.247 billion	$5.492 billion	$6.757 billion
Future Escalation to WEC*	$794 million	$813 million	$19 million
Total Expected Project Cost (SCE&G's 55% share)	$6.827 billion	$7.113 billion	$7.601 billion
Liquidated Damages	$155 million at 100%$86 million - SCE&G	$926 million at 100% $509 million - SCE&G	$676 million at 100% $372 million - SCE&G
Bonuses	Capacity Performance Related	Completion - Capacity Performance bonus removed $550 million at 100% $303 million - SCE&G	$300 million at 100% $165 million - SCE&G
Change in Law Language	Generally defined	Explicitly defined - Formal written adoption of a new statute, regulation, requirement, or code or new NRC regulatory requirement that did not exist as of this amendment	

* The fixed price option, regardless of date of acceptance, would fix project costs and shift the risk of escalation (excluding escalation primarily on owner's and transmission costs) to WEC as of June 30, 2015. Total gross escalation recorded as of June 30, 2015 is $386 million. Under the fixed price option, total gross escalation remaining on the project is estimated to be approximately $145 million.

Following an evaluation as to whether to exercise the fixed price option, SCE&G expects to file a petition, as provided under the BLRA, for an update to the project's estimated capital cost schedule which would incorporate the impact of the October 2015 Amendment. Refer to the Exhibit Index for information on where a copy of the October 2015 Amendment is available publicly.

The information summarized above, as well as additional information on these and other related matters, is further discussed at Note 2 and Note 10 to the consolidated financial statements.

Environmental

EPA regulations have a significant impact on Consolidated SCE&G's electric operations. In 2015, several regulations were proposed or became final, including the following:

- On June 29, 2015, the Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate mercury and other specified air pollutants under the MATS rule, but did not vacate MATS. The EPA has indicated that it expects to issue a revised rule responsive to the issue raised by the Supreme Court by April 15, 2016. SCE&G and GENCO have received a one-year extension (until April 2016) to comply with MATS at certain of their generating stations. These extensions will allow time to convert one generating station to burn natural gas and to install additional pollution control devices at other generating stations. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

- A revised standard for new power plants under the CAA was proposed on August 3, 2015, and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. This rule effectively prevents construction of new coal-fired plants without partial carbon capture and sequestration capabilities.

- On August 3, 2015, the EPA issued its final rule under the Clean Power Plan that would regulate carbon dioxide emissions from existing units. This rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. Any costs incurred to comply with such rule are expected to be recoverable through rates.

- The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved in connection with the renewal (every five years) of state-issued NPDES permits. The ELG Rule became effective January 4, 2016. SCE&G and GENCO expect that wastewater treatment technology retrofits will be required at two generating stations and may be required at other facilities. The extent of the station-specific retrofits required and the related schedule for compliance will be determined in connection with each plant's NPDES permit renewal.

- New federal regulations affecting the management and disposal of CCRs became effective in the fourth quarter of 2015. Under these regulations, CCRs will not be regulated as hazardous waste. These regulations do impose certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. These regulations are not expected to have a material effect on SCE&G and GENCO because SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The above environmental initiatives and similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, Consolidated SCE&G cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on Consolidated SCE&G, if any. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The local distribution operations of SCE&G purchases, transports and sells natural gas to approximately 348,000 retail customers (as of December 31, 2015) in portions of South Carolina. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25%.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact SCE&G’s ability to retain large commercial and industrial customers. In addition, the production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at such levels for the foreseeable future.

RESULTS OF OPERATIONS

Net Income

Net income for Consolidated SCE&G was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Net income	$ 479.5	4.8%	$ 457.7	17.1%	$ 390.8

2015 vs 2014

Net income increased primarily due to higher electric margin, higher gas distribution margin and lower depreciation expense, partially offset by lower other income, higher operation and maintenance expense, higher property taxes, higher interest cost, and higher income taxes, as further described below.

2014 vs 2013

Net income increased primarily due to the effects of weather, customer growth and base rate increases under the BLRA. Higher electric and gas margins were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.

Dividends Declared

Consolidated SCE&G's Boards of Directors declared the following dividends on common stock (all of which was held by SCANA):

Declaration Date	Dividend Amount	Quarter Ended	Payment Date
February 18, 2016	$74.2 million	March 31, 2016	April 1, 2016
February 20, 2015	$70.7 million	March 31, 2015	April 1, 2015
April 30, 2015	$69.7 million	June 30, 2015	July 1, 2015
July 30, 2015	$70.5 million	September 30, 2015	October 1, 2015
October 29, 2015	$74.5 million	December 31, 2015	January 1, 2016
February 20, 2014	$64.3 million	March 31, 2014	April 1, 2014
April 24, 2014	$64.4 million	June 30, 2014	July 1, 2014
July 31, 2014	$68.5 million	September 30, 2014	October 1, 2014
October 30, 2014	$74.4 million	December 31, 2014	January 1, 2015

When a dividend payment date falls on a weekend or holiday, the payment is made the following business day.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 2,557.1	(2.7)%	$ 2,629.4	8.2%	$ 2,430.5
Less: Fuel used in electric generation	660.6	(17.4)%	799.3	6.4%	751.0
Purchased power	52.1	(35.4)%	80.7	87.7%	43.0
Margin	1,844.4	5.4 %	1,749.4	6.9%	1,636.5
Other operation and maintenance expenses	509.6	0.4 %	507.5	3.6%	489.9
Depreciation and amortization	266.9	(7.8)%	289.5	0.4%	288.3
Other taxes	192.4	4.1 %	184.8	3.2%	179.0
Operating Income	$ 875.5	14.1 %	$ 767.6	13.0%	$ 679.3

2015 vs 2014

- Margin increased due to downward adjustments of $69.0 million in 2014, compared to downward adjustments of $19.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and DSM Programs. These adjustments had no effect on net income as they were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts, lower depreciation expense upon the adoption and implementation of revised depreciation rates as a result of an updated depreciation study and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve. Margin also increased due to base rate increases under the BLRA of $65.7 million and residential and commercial customer growth of $21.4 million. These increases were partially offset by $25.6 million due to the effects of weather, lower industrial margins of $14.6 million primarily due to variable price contracts, and lower collections under the rate rider for pension costs of $3.0 million. See Note 2 to the consolidated financial statements.
- Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider collections.
- Depreciation and amortization decreased by $28.7 million in 2015 due to the implementation of the above mentioned revised depreciation rates, $14.5 million of which was offset by downward revenue adjustments. This decrease in depreciation expense was partially offset by increases associated with net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Electric margin increased due to the effects of weather of $43.5 million, base rate increases under the BLRA of $54.1 million and customer growth of $14.7 million. These margin increases were partially offset by downward adjustments of $69.0 million in 2014, compared to downward adjustments of $50.1 million in 2013, pursuant to SCPSC orders related to fuel cost recovery, the reversal of undercollected amounts related to SCE&G's eWNA program (the eWNA was discontinued effective with the first billing cycle of 2014) and DSM Programs. Such adjustments are fully offset by the recognition within other income of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve, both of which had been deferred in regulatory accounts. See Note 2 to the consolidated financial statements.
- Operations and maintenance expenses increased due to nonlabor operating expenses of $8.9 million, DSM Programs cost amortization of $2.1 million, higher labor expense of $1.1 million which includes incentive compensation and lower pension cost recognition, storm expenses of $1.1 million and other general expenses of $1.9 million.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2015	Change	2014	Change	2013
Residential	7,978	(2.2)%	8,156	7.7	7,571
Commercial	7,386	0.2 %	7,371	2.3%	7,205
Industrial	6,201	(0.5)%	6,234	3.9%	6,000
Other	595	(0.8)%	600	3.3%	581
Total retail sales	22,160	(0.9)%	22,361	4.7%	21,357
Wholesale	942	(1.7)%	958	0.3%	955
Total	23,102	(0.9)%	23,319	4.5%	22,312

2015 vs 2014

Retail sales volumes decreased primarily due to the effects of weather, partially offset by customer growth.

2014 vs 2013

Retail sales volumes increased primarily due to the effects of weather and customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 372.7	(19.4)%	$ 462.2	11.5%	$ 414.4
Less: Gas purchased for resale	192.5	(32.0)%	283.1	16.0%	244.1
Margin	180.2	0.6 %	179.1	5.2%	170.3
Other operation and maintenance expenses	69.8	3.1 %	67.7	1.7%	66.6
Depreciation and amortization	26.8	4.3 %	25.7	2.4%	25.1
Other taxes	24.9	7.8 %	23.1	9.0%	21.2
Operating Income	$ 58.7	(6.2)%	$ 62.6	9.1%	$ 57.4

2015 vs 2014

- Margin increased by $4.3 million due to customer growth partially offset by a decrease of $3.1 million due to a SCPSC-approved decrease in base rates under the RSA which became effective in November 2014.
- Operation and maintenance expenses increased due to higher labor costs of $1.1 million, primarily due to incentive compensation.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Margin increased primarily due to residential and commercial customer growth of $4.0 million and increased average usage of $2.5 million.
- Operations and maintenance expense increased $1.3 million due to labor.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2015	Change	2014	Change	2013
Residential	12,086	(19.0)%	14,917	19.2 %	12,515
Commercial	12,580	(9.7)%	13,936	9.0 %	12,786
Industrial	17,901	(2.2)%	18,307	(10.3)%	20,411
Transportation gas	4,781	11.5 %	4,286	(10.7)%	4,801
Total	47,348	(8.0)%	51,446	1.8 %	50,513

2015 vs 2014

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use. These decreases were partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to a shift to transportation service from system supply and the impact of curtailments. Transportation volumes increased due to customers shifting to transportation only service.

2014 vs 2013

Residential and commercial sales volumes increased primarily due to the effects of weather and customer growth. Industrial sales volumes decreased due to weather related curtailments and a customer switching to an alternative fuel source. Transportation sales volumes decreased due to weather related curtailments.

Other Operating Expenses

Other operating expenses (including transactions with affiliates) were as follows:

Millions of dollars		2015	Change		2014	Change		2013
Other operation and maintenance	$	579.4	0.7 %	$	575.2	3.4%	$	556.5
Depreciation and amortization		293.7	(6.8)%		315.2	0.6%		313.4
Other taxes		217.3	4.5 %		207.9	3.8%		200.2

Changes in other operating expenses are addressed in the electric operations and gas distribution segments.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on Consolidated SCE&G's income statements and balance sheets as follows:

Millions of dollars		2015	Change		2014	Change		2013
Income Statement Impact:								
Employee benefit costs	$	2.8	(30.0)%	$	4.0	(63.6)%	$	11.0
Other expense		0.2	100.0 %		0.1	(83.3)%		0.6
Balance Sheet Impact:								
Increase in capital expenditures		3.4	*		0.3	(95.3)%		6.4
Component of amount receivable from Summer Station co-owner		1.5	*		0.1	(96.0)%		2.5
Increase (decrease) in regulatory assets		6.2	*		(3.2)	*		5.5
Net periodic benefit cost	$	14.1	*	$	1.3	(96.0)%	$	26.0

* Greater than 100%

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were as follows:

Millions of dollars		2015		2014		2013
Retail electric operations	$	2.0	$	2.0	$	2.0
Gas operations		1.0		1.0		0.2

Other Income (Expense)

Other income (expense) includes the results of certain incidental non-utility activities and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. Consolidated SCE&G includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. Components of other income (expense) were as follows:

Millions of dollars		2015	Change		2014	Change		2013
Other income	$	31.1	(61.0)%	$	79.8	51.4%	$	52.7
Other expense		(31.1)	(8.0)%		(33.8)	93.1%		(17.5)
AFC - equity funds		24.8	(10.5)%		27.7	10.4%		25.1

2015 vs 2014

Other income decreased due primarily to the recognition of $64.0 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). AFC decreased due to lower AFC rates.

2014 vs 2013

Other income (expense) increased primarily due to the recognition of $64.0 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed, compared to $50.1 million of such gains in 2013. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income. Donations increased $4.6 million, equity partnership losses increased $2.3 million and AFC increased $2.6 million.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Interest on long-term debt, net	$ 236.0	8.5%	$ 217.6	5.2 %	$ 206.8
Other interest expense	12.1	16.3%	10.4	(1.0)%	10.5
Total	$ 248.1	8.8%	$ 228.0	4.9 %	$ 217.3

Interest on long-term debt increased in each year primarily due to increased long-term borrowings.

Income Taxes

Income tax expense increased each year primarily due to increases in income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its contractual cash obligations will be met through internally generated funds and additional short- and long-term borrowings. Consolidated SCE&G expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Consolidated SCE&G’s cash requirements arise primarily from its operational needs, funding its construction programs and payment of dividends to SCANA. The ability of Consolidated SCE&G to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental
regulations, will depend upon its ability to attract the necessary financial capital on reasonable terms. Consolidated SCE&G recovers the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and Consolidated SCE&G continues its ongoing construction program, Consolidated SCE&G expects to seek increases in rates. Consolidated SCE&G’s future financial position and results of operations will be affected by Consolidated SCE&G’s ability to obtain adequate and timely rate and other regulatory relief.

Rating agencies consider qualitative and quantitative factors when assessing Consolidated SCE&G's credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of Consolidated SCE&G's commonly monitored financial credit metrics could adversely affect Consolidated SCE&G's debt ratings. This could cause Consolidated SCE&G to pay higher interest rates on its long- and short-term indebtedness, and could limit Consolidated SCE&G's access to capital markets and liquidity.

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.0 billion in 2015. Consolidated SCE&G’s current estimates of its capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2016	2017	2018
Consolidated SCE&G - Normal			
Generation	$ 88	$ 130	$ 91
Transmission & Distribution	192	163	187
Other	12	9	15
Gas	61	63	60
Common	3	2	4
Total Consolidated SCE&G - Normal	356	367	357
New Nuclear (including transmission)	1,166	1,013	677
Cash Requirements for Construction	1,522	1,380	1,034
Nuclear Fuel	122	80	89
Total Estimated Capital Expenditures	$ 1,644	$ 1,460	$ 1,123

Consolidated SCE&G's contractual cash obligations as of December 31, 2015 are summarized as follows:

Contractual Cash Obligations

	Payments due by period				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term and short-term debt including interest	$ 10,850	$ 777	$ 1,425	$ 454	$ 8,194
Capital leases	16	4	9	1	2
Operating leases	26	4	4	1	17
Purchase obligations	3,468	1,735	1,621	112	—
Other commercial commitments	2,725	450	825	700	750
Total	$ 17,085	$ 2,970	$ 3,884	$ 1,268	$ 8,963

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at Summer Station. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent. SCE&G estimates it will cost $750 million to $850 million to acquire an additional 5% ownership in the New Units and has included $750 million for this purpose in other commercial commitments. See also New Nuclear Construction in Note 10 to the consolidated financial statements.

Purchase obligations includes customary purchase orders under which SCE&G has the option to utilize certain vendors without the obligation to do so. SCE&G may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations for coal and nuclear fuel purchases. SCE&G also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional AROs that are not listed in the contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

Consolidated SCE&G is party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 6 to the consolidated financial statements. At December 31, 2015, Consolidated SCE&G had posted $13 million in cash collateral related to interest rate derivative contracts.

In connection with the effectiveness of the October 2015 Amendment, SCE&G accrued within accounts payable $250 million (SCE&G's 55% share is $137.5 million) as of December 31, 2015 for the settlement and release of substantially all outstanding disputes between SCE&G and the Consortium. These amounts are not included in capital expenditures and contractual cash obligations above. See Note 10 to the consolidated financial statements.

Consolidated SCE&G has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements. In addition Consolidated SCE&G has recorded liabilities for certain unrecognized tax benefits that are not included in contractual cash obligations. See Note 5 to the consolidated financial statements.

Financing Limits and Related Matters

Consolidated SCE&G's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including the SCPSC and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

In December 2015, the Consolidated SCE&G's existing five-year committed LOCs were amended and extended by one year. At December 31, 2015 SCE&G and Fuel Company were parties to five-year credit agreements in the amounts of $1.2 billion, (of which $500 million relates to Fuel Company) which expire in December 2020. In addition, at December 31, 2015 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2015, Consolidated SCE&G had no outstanding borrowings under its $1.4 billion facilities, had approximately $420 million in commercial paper borrowings outstanding, was obligated under $.3 million in LOC-supported letters of credit, and had approximately $130 million in cash and temporary investments. Consolidated SCE&G regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance
on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2015 were approximately $422 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2015, Consolidated SCE&G's long-term debt portfolio has a weighted average maturity of approximately 23 years and bears an average cost of 5.8%. Substantially all of Consolidated SCE&G's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, Consolidated SCE&G rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

SCE&G's Restated Articles of Incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock, all of which is beneficially owned by SCANA.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015, approximately $72.4 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Financing Activities

During 2015, net cash inflows related to financing activities totaled approximately $54 million, primarily associated with the issuance of long-term debt and contributions from parent, partially offset by repayment of short- and long-term debt and payment of dividends.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G’s construction program, to finance capital expenditures, and for general corporate purposes.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G’s construction program, to finance capital expenditures, and for general corporate purposes.

Investing Activities

To settle interest rate derivative contracts, SCE&G paid approximately $253 million, net, in 2015, approximately $95 million in 2014 and approximately $6 million, net, through the third quarter of 2013. During the fourth quarter of 2013, SCE&G received approximately $120 million upon the settlement of interest rate derivatives.

For additional information, see Note 4 to the consolidated financial statements.

Major tax incentives included within federal legislation resulted in the allowance of bonus depreciation for property placed in service in 2008 through 2015. These incentives, along with certain other deductions, have had a positive impact on the cash flows of Consolidated SCE&G. Bonus depreciation will also be significant for 2016 through 2019 under recent law.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2015, were as follows:

December 31,	2015	2014	2013	2012	2011
SCE&G	3.69	3.77	3.48	3.29	3.13

NEW NUCLEAR CONSTRUCTION MATTERS

For a discussion of developments related to new nuclear construction, see Note 2 and Note 10 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, Consolidated SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

For the three years ended December 31, 2015, Consolidated SCE&G's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $41.4 million. During this same period, Consolidated SCE&G expended approximately $38.5 million for the construction and retirement of landfills and ash ponds, net of disposal proceeds. In addition, Consolidated SCE&G made expenditures to operate and maintain environmental control equipment at its fossil plants of $8.7 million in 2015, $9.1 million in 2014 and $9.2 million in 2013, which are included in other operation and maintenance expense, and made expenditures to handle waste ash, net of disposal proceeds, of $1.3 million in 2015, $1.6 million in 2014 and $3.2 million in 2013, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2015, 2014 and 2013 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for Consolidated SCE&G are $15.3 million for 2016 and $88.9 million for the four-year period 2017-2020. These expenditures are included in Consolidated SCE&G's Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though Consolidated SCE&G cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. Consolidated SCE&G cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact Consolidated SCE&G, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to Consolidated SCE&G's electric system, as well as impacts on employees and customers and on Consolidated SCE&G's supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow Consolidated SCE&G to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCE&G, GENCO and Fuel Company are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCE&G, GENCO and Fuel Company	The CFTC, under Dodd-Frank, concerning recordkeeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCE&G, GENCO and Fuel Company engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, and other matters; the PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to the issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system is subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. SCE&G has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. SCE&G is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of Consolidated SCE&G's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Accounting for Rate Regulated Operations

Consolidated SCE&G's regulated operations record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, Consolidated SCE&G may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of Consolidated SCE&G's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of Consolidated SCE&G's regulatory assets and liabilities.

Consolidated SCE&G's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, Consolidated SCE&G could be required to write down its investment in those assets. Consolidated SCE&G cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect Consolidated SCE&G's results of operations in the period in which they would be recorded. As of December 31, 2015, Consolidated SCE&G's net investments in fossil/hydro and nuclear generation assets were $2.3 billion and $4.1 billion, respectively.

In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could also be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, SCE&G records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2015 and 2014, accounts receivable included unbilled revenues of $101.5 million and $115.8 million, respectively, compared to total revenues of $2.9 billion and $3.1 billion for the years 2015 and 2014, respectively.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact SCE&G's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1on an after-tax basis.

Asset Retirement Obligations

Consolidated SCE&G accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from the acquisition, construction, development and normal operation in accordance with applicable accounting guidance. Consolidated SCE&G recognizes obligations at present value in the period in which they are incurred, and capitalizes associated asset retirement costs as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to Consolidated SCE&G's utility operations, their recognition has no significant impact on results of operations. As of December 31, 2015, Consolidated SCE&G has recorded AROs of $176 million for nuclear plant decommissioning (as discussed above) and AROs of $312 million for other conditional obligations related to generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of imprecision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees. SCANA recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. SCANA's net pension cost of $18.0 million ($14.2 million attributable to SCE&G) recorded in 2015 reflects the use of a 4.20% discount rate derived using a cash flow matching technique, and an assumed 7.50% long-term rate of return on plan assets. SCANA believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2015 would have increased SCANA's pension cost by $1.9 million and increased the pension obligation by $26.8 million. Further, had the assumed long-term rate of return on assets been 7.25%, SCANA's pension cost for 2015 would have increased by $2.1 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

SCANA determines the fair value of the majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, SCANA evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2015, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.0%, 5.4%, 8.7% and 8.8%, respectively. The 2015 expected long-term rate of return of 7.50% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. SCANA regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2016, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.3%, 4.6%, 7.2% and 8.7%, respectively. For 2016, the expected rate of return is 7.50%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the significance of pension costs and the criticality of the related estimates to SCE&G's financial statements will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. SCANA accounts for the cost of the postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. SCANA used a discount rate of 4.30%, derived using a cash flow matching technique, and recorded a net cost to SCE&G of $15.8 million for 2015. Had the selected discount rate been 4.05% (25 basis points lower than the discount rate referenced above), the expense for 2015 would have been $0.6 million higher and increased the obligation by $9.5 million. Because the plan provisions include "caps" on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

OTHER MATTERS

Off-Balance Sheet Arrangements

Consolidated SCE&G holds insignificant investments in securities and businesses ventures. Consolidated SCE&G does not engage in significant off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

The tables below provide information about long-term debt issued by Consolidated SCE&G which is sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2015	Expected Maturity Date							
Millions of dollars	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	110.4	10.1	719.8	9.1	8.3	3,873.0	4,730.7	5,095.0
Average Fixed Interest Rate (%)	1.13	4.50	6.02	4.73	4.94	5.71	5.64	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	63.7
Average Variable Interest Rate (%)	—	—	—	—	—	0.03	0.03	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	650.0	550.0	—	—	—	71.4	1,271.4	(49.8)
Average Pay Interest Rate (%)	2.87	2.88	—	—	—	3.28	2.90	—
Average Receive Interest Rate (%)	0.61	0.61	—	—	—	0.01	0.58	—

December 31, 2014	Expected Maturity Date							
Millions of dollars	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	9.9	109.4	9.0	718.6	8.1	3,379.7	4,234.8	4,999.8
Average Fixed Interest Rate (%)	4.54	1.11	4.73	5.95	4.97	5.29	5.29	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	65.2
Average Variable Interest Rate (%)	—	—	—	—	—	0.04	0.04	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	950.0	100.0	—	—	—	67.8	1,117.8	(233.0)
Average Pay Interest Rate (%)	3.83	3.63	—	—	—	3.28	3.78	—
Average Receive Interest Rate (%)	0.26	0.26	—	—	—	0.04	0.24	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of Consolidated SCE&G’s long-term debt and interest rate derivatives, see ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

South Carolina Electric & Gas Company and Affiliates
Consolidated Balance Sheets

December 31, (Millions of dollars)	2015	2014
Assets		
Utility Plant In Service	$ 11,153	$ 10,650
Accumulated Depreciation and Amortization	(3,869)	(3,667)
Construction Work in Progress	3,997	3,302
Plant to be Retired, Net	—	169
Nuclear Fuel, Net of Accumulated Amortization	308	329
Utility Plant, Net ($700 and $675 related to VIEs)	11,589	10,783
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	68	67
Assets held in trust, net-nuclear decommissioning	115	113
Other investments	1	2
Nonutility Property and Investments, Net	184	182
Current Assets:		
Cash and cash equivalents	130	100
Receivables:		
Customer, net of allowance for uncollectible accounts of $3 and $4	324	413
Affiliated companies	22	109
Other	202	111
Inventories:		
Fuel	98	131
Materials and supplies	136	129
Prepayments	92	154
Other current assets	15	99
Total Current Assets ($88 and $158 related to VIEs)	1,019	1,246
Deferred Debits and Other Assets:		
Pension asset	—	10
Regulatory assets	1,857	1,745
Other	116	112
Total Deferred Debits and Other Assets ($53 and $50 related to VIEs)	1,973	1,867
Total	$ 14,765	$ 14,078

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2015	2014
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,760	$ 2,560
Retained Earnings	2,265	2,077
Accumulated Other Comprehensive Loss	(3)	(3)
Total Common Equity	5,022	4,634
Noncontrolling interest	129	123
Total Equity	5,151	4,757
Long-Term Debt, net	4,659	4,270
Total Capitalization	9,810	9,027
Current Liabilities:		
Short-term borrowings	420	709
Current portion of long-term debt	110	10
Accounts payable	469	294
Affiliated payables	113	180
Customer deposits and customer prepayments	93	61
Taxes accrued	299	170
Interest accrued	66	64
Dividends declared	75	74
Derivative financial instruments	34	208
Other	61	71
Total Current Liabilities	1,740	1,841
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,732	1,724
Asset retirement obligations	488	536
Pension and postretirement benefits	186	195
Regulatory liabilities	635	610
Other	157	122
Other -affiliate	17	23
Total Deferred Credits and Other Liabilities	3,215	3,210
Commitments and Contingencies (Note 10)	—	—
Total	$ 14,765	$ 14,078

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Income

For the Years Ended December 31, (Millions of dollars)	2015	2014	2013
Operating Revenues:			
Electric	$ 2,557	$ 2,629	$ 2,431
Gas	373	462	414
Total Operating Revenues	2,930	3,091	2,845
Operating Expenses:			
Fuel used in electric generation	661	799	751
Purchased power	52	81	43
Gas purchased for resale	193	283	244
Other operation and maintenance	579	575	557
Depreciation and amortization	294	315	313
Other taxes	217	208	200
Total Operating Expenses	1,996	2,261	2,108
Operating Income	934	830	737
Other Income (Expense):			
Other income	31	80	53
Other expenses	(31)	(34)	(18)
Interest charges, net of allowance for borrowed funds used during construction of $14, $14 and $13	(248)	(228)	(217)
Allowance for equity funds used during construction	25	28	25
Total Other Expense	(223)	(154)	(157)
Income Before Income Tax Expense	711	676	580
Income Tax Expense	231	218	189
Net Income	480	458	391
Less Net Income Attributable to Noncontrolling Interest	14	12	11
Earnings Available to Common Shareholder	$ 466	$ 446	$ 380
Dividends Declared on Common Stock	$ 285	$ 272	$ 257

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Comprehensive Income

Years Ended December 31, (Millions of dollars)	2015	2014	2013
Net Income	$ 480	$ 458	$ 391
Other Comprehensive Income (Loss), net of tax:			
Deferred costs of employee benefit plans, net of tax $-, $- and $-	—	—	1
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax $-, $- and $-	—	—	—
Other Comprehensive Income (Loss)	—	—	1
Total Comprehensive Income	480	458	392
Less comprehensive income attributable to noncontrolling interest	(14)	(12)	(11)
Comprehensive income available to common shareholder	$ 466	$ 446	$ 381

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2015	2014	2013
Cash Flows From Operating Activities:			
Net income	$ 480	$ 458	$ 391
Adjustments to reconcile net income to net cash provided from operating activities:			
Losses from equity method investments	4	5	3
Deferred income taxes, net	8	187	29
Depreciation and amortization	294	318	315
Amortization of nuclear fuel	46	45	57
Allowance for equity funds used during construction	(25)	(28)	(25)
Carrying cost recovery	(12)	(9)	(3)
Changes in certain assets and liabilities:			
Receivables	85	51	(53)
Receivables - affiliate	16	(90)	17
Inventories	(24)	(52)	35
Prepayments	70	(89)	8
Regulatory assets	150	(350)	83
Other regulatory liabilities	1	(132)	54
Accounts payable	11	(49)	12
Accounts payable - affiliate	(17)	63	(7)
Taxes accrued	129	(53)	72
Pension and other postretirement benefits	(5)	106	(186)
Derivative financial instruments	(174)	207	(65)
Other assets	38	12	27
Other liabilities	9	50	146
Other liabilities - affiliate	(6)	(9)	(58)
Net Cash Provided From Operating Activities	1,078	641	852
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,008)	(934)	(1,003)
Proceeds from investments and sales of assets (including derivative collateral returned)	975	275	144
Purchase of investments (including derivative collateral posted)	(887)	(381)	(116)
Payments upon interest rate derivative contract settlement	(263)	(95)	(49)
Proceeds from interest rate derivative contract settlement	10	—	163
Proceeds from investment in affiliate	71	—	—
Investment in affiliate	—	(80)	—
Net Cash Used For Investing Activities	(1,102)	(1,215)	(861)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	491	294	451
Repayment of long-term debt	(11)	(48)	(251)
Dividends	(285)	(260)	(241)
Short-term borrowings, net	(289)	458	(198)
Short-term borrowings-affiliate, net	(50)	56	(22)
Contribution from parent	204	89	314
Return of capital to parent	(4)	(7)	(3)
Deferred financing costs	(2)	—	—
Net Cash Provided From Financing Activities	54	582	50
Net Increase in Cash and Cash Equivalents	30	8	41
Cash and Cash Equivalents, January 1	100	92	51
Cash and Cash Equivalents, December 31	$ 130	$ 100	$ 92
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $14, $14 and $13)	$ 228	$ 210	$ 200
—Income taxes paid	89	177	92
—Income taxes received	84	—	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	230	151	100
Capital lease	6	5	4
Nuclear fuel purchase	—	—	98

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Changes in Equity

	Common Stock											
Millions	**Shares**		**Amount**		**Retained Earnings**		**Accumulated Other Comprehensive Income (Loss)**		**Non-controlling Interest**		**Total Equity**
Balance at January 1, 2013	40	$	2,167	$	1,766	$	(4)	$	114	$	4,043
Earnings available for common shareholder					380				11		391
Deferred cost of employee benefit plans, net of tax $-							1				1
Total Comprehensive Income (Loss)					380		1		11		392
Capital contributions from (returned to) parent			312						(1)		311
Cash dividends declared					(250)				(7)		(257)
Balance at December 31, 2013	40		2,479		1,896		(3)		117		4,489
Earnings Available for Common Shareholder					446				12		458
Deferred Cost of Employee Benefit Plans, net of tax $-							—				—
Total Comprehensive Income (Loss)					446		—		12		458
Capital contributions from parent			81						1		82
Cash dividends declared					(265)				(7)		(272)
Balance at December 31, 2014	40		2,560		2,077		(3)		123		4,757
Earnings Available for Common Shareholder					466				14		480
Deferred Cost of Employee Benefit Plans, net of tax $-							—				—
Total Comprehensive Income					466		—		14		480
Capital contributions from parent			200						—		200
Cash dividends declared					(278)				(8)		(286)
Balance at December 31, 2015	40	$	2,760	$	2,265	$	(3)	$	129	$	5,151

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs), and accordingly, the accompanying consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. Accordingly, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's consolidated financial statements. Intercompany balances and transactions between SCE&G, Fuel Company and GENCO have been eliminated in consolidation.

GENCO owns a coal-fired electric generating station with a 605 megawatt net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $491 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

In April 2015, the FASB issued accounting guidance intended to simplify the presentation of debt issuance costs by requiring that such costs be deducted from carrying amounts related to debt when presented in the balance sheet. As permitted, Consolidated SCE&G adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $29 million of unamortized debt issuance costs were reclassified to long-term debt, and certain amounts in Note 4 and Note 12 were also reclassified for comparative periods. The effect of adoption on Consolidated SCE&G's results of operations and cash flows was not significant.

In November 2015, the FASB issued accounting guidance intended to simplify the presentation of deferred tax assets and deferred tax liabilities by netting and classifying them as noncurrent on the statement of financial position. As permitted, Consolidated SCE&G early adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $27.9 million of net deferred tax liabilities previously classified in current liabilities were reclassified to long-term liabilities. The effect of adoption on Consolidated SCE&G's results of operations and cash flows was not significant.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. Consolidated SCE&G calculated AFC using average composite rates of 5.6% for 2015, 6.5% for 2014 and 6.9% for 2013. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Consolidated SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. The composite weighted average depreciation rates for utility plant assets were 2.56% in 2015, 2.84% in 2014 and 2.94% in 2013.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in “Fuel used in electric generation” and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2015		2014	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 620.4 million	—	$ 578.3 million	—
Construction work in progress	$ 214.6 million	$ 3.4 billion	$ 199.3 million	$ 2.7 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $178.8 million at December 31, 2015 and $88.9 million at December 31, 2014.

Plant to be Retired

At December 31, 2014, SCE&G expected to retire three units that are or were coal-fired by 2020, which was prior to the end of the previously estimated useful lives over which the units were being depreciated. As such, these units were identified as Plant to be Retired. Subsequently, these units were converted to be gas-fired. In the third quarter of 2015, in connection with the adoption of a customary depreciation study and related analysis (see Note 2), SCE&G determined that these units would not likely be retired by 2020, and their depreciation rates were set to recover the units' net carrying value over their respective revised useful lives. Accordingly, the net carrying value of these units is no longer classified as Plant to be Retired at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2015 and 2014, SCE&G incurred $16.5 million and $19.4 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, effective January 1, 2013, SCE&G accrues $1.4 million per month for its portion of the nuclear refueling outages that are scheduled for the spring of 2014 throught the spring of 2020. Total costs for 2014 were $43.7 million, of which SCE&G was responsible for $29.1 million. Total costs for 2015 were $40.2 million, of which SCE&G was responsible for $26.8 million.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each period presented) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Consolidated SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.
Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

Consolidated SCE&G is included in the consolidated federal income tax returns of SCANA. Under a joint consolidated income tax allocation agreement, each SCANA subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or record revenue in a period different from the period in which the revenue would be recorded by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations to be refunded to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as receivables or accounts payable, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Consolidated SCE&G presents long-term debt premiums, discounts and debt issuance costs within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

Consolidated SCE&G presents the revenues and expenses of its regulated activities (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

Consolidated SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $101.5 million at December 31, 2015 and $115.8 million at December 31, 2014.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

Customers subject to the PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. An eWNA for SCE&G's electric customers was discontinued effective with the first billing cycle of 2014 as approved by the SCPSC.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

New Accounting Matters

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Consolidated SCE&G is required to adopt this guidance in the first quarter of 2018 and early adoption is permitted in the first quarter of 2017. Adoption using a retrospective method is required, with options to elect certain practical expedients or to recognize a cumulative effect in the year of initial adoption. Consolidated SCE&G has not determined when it will adopt this guidance or what elections it will make. Consolidated SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other things, the guidance clarifies how to account for a software license element included in a cloud computing arrangement, and makes explicit that a cloud computing arrangement not containing a software license element should be accounted for as a service contract. Consolidated SCE&G has determined that this guidance, when adopted in the first quarter of 2016, will not significantly impact Consolidated SCE&G's results of operations, cash flows or financial position.

In July 2015, the FASB issued accounting guidance intended to simplify the subsequent measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. Consolidated SCE&G expects to adopt this guidance when required in the first quarter of 2017. Consolidated SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In January 2016, the FASB issued accounting guidance intended to clarify the classification and measurement of financial instruments and financial liabilities, among other things. Consolidated SCE&G expects to adopt this guidance when required in the first quarter of 2018. Consolidated SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over twelve months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily of the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for year beginning in 2019. Consolidated SCE&G has not determined what impact this guidance will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to a November 2013 SCPSC accounting order, SCE&G's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. SCE&G is to make a good faith effort to have at least 30 MW of utility-scale solar capacity in service by the end of 2016.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

In October 2015, the SCPSC initiated its 2016 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 7, 2016.

Electric - Base Rates

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

Pursuant to an SCPSC order, SCE&G removes from rate base deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $9.5 million and $5.8 million during 2015 and 2014, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G’s request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G’s DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

In January 2016, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would allow recovery of $37.6 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Through 2015, requested rate adjustments have been based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2015	2.6%	$64.5 million
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million

In September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed. See Note 10.

Gas

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2015	No change	—
2014	0.6% Decrease	$ 2.6 million
2013	No change	—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, Consolidated SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	December 31, 2015	2014
Regulatory Assets:		
Accumulated deferred income taxes	$ 291	$ 278
AROs and related funding	384	347
Deferred employee benefit plan costs	295	310
Deferred losses on interest rate derivatives	535	453
Unrecovered plant	127	137
Environmental remediation costs	35	36
DSM Programs	61	56
Other	129	128
Total Regulatory Assets	$ 1,857	$ 1,745
Regulatory Liabilities:		
Asset removal costs	519	505
Deferred gains on interest rate derivatives	96	82
Other	20	23
Total Regulatory Liabilities	$ 635	$ 610

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to AFC and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G will amortize these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recoverable over periods of up to approximately 24 years.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2015 SCPSC order, deferred costs are currently being recovered over approximately five years through an approved rate rider.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2015 and 2014. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2015 and 2014.

SCE&G's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015 and 2014, retained earnings of approximately $72.4 million and $67.7 million, respectively, were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Total long-term debt, net reflects the retrospective adoption of accounting guidance for unamortized debt issuance costs in the fourth quarter of 2015 (see Note 1). Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2015		2014	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
First Mortgage Bonds (secured)	2018 - 2065	$ 4,340	5.78%	$ 3,840	5.56%
GENCO Notes (secured)	2016 - 2024	220	5.92%	227	5.90%
Industrial and Pollution Control Bonds (a)	2028 - 2038	122	3.51%	122	3.51%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other	2016 - 2027	17	2.63%	14	2.63%
Total debt		4,799		4,303	
Current maturities of long-term debt		(110)		(10)	
Unamortized premium, net		2		6	
Unamortized debt issuance costs		(32)		(29)	
Total long-term debt, net		$ 4,659		$ 4,270	

(a) Includes variable rate debt of $67.8 million at December 31, 2015 (rate of 0.03%) and 2014 (rate of 0.04%), which are hedged by fixed swaps.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Long-term debt maturities will be $110 million in 2016, $10 million in 2017, $720 million in 2018, $9 million in 2019 and $8 million in 2020.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Lines of Credit and Short-Term Borrowings

At December 31, 2015 and 2014, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	2015	2014
Lines of credit:		
Total committed long-term	$ 1,400	$ 1,400
Outstanding commercial paper (270 or fewer days)	$ 420	$ 709
Weighted average interest rate	0.74%	0.52%
Letters of credit supported by an LOC	$ 0.3	$ 0.3
Available	$ 980	$ 691

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company). In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In December 2015, the term of the five-year agreements was amended and extended by one year, such that they expire in December 2020. The three-year agreement expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. Consolidated SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2015 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $33 million and money pool investments due from an affiliate of $9 million. At December 31, 2014 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $83 million and money pool investments due from an affiliate of $80 million. On the consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	2015	2014	2013
Current taxes:			
Federal	$ 208	$ 39	$ 146
State	32	(6)	13
Total current taxes	240	33	159
Deferred tax (benefit) expense, net:			
Federal	(3)	157	25
State	(3)	32	9
Total deferred taxes	(6)	189	34
Investment tax credits:			
Amortization of amounts deferred—state	(1)	(1)	(1)
Amortization of amounts deferred—federal	(2)	(3)	(3)
Total investment tax credits	(3)	(4)	(4)
Total income tax expense	$ 231	$ 218	$ 189

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2015	2014	2013
Net income	$ 466	$ 446	$ 380
Income tax expense	231	218	189
Noncontrolling interest	14	12	11
Total pre-tax income	$ 711	$ 676	$ 580
Income taxes on above at statutory federal income tax rate	$ 249	$ 237	$ 203
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	24	21	18
State investment tax credits (less federal income tax effect)	(6)	(5)	(5)
Allowance for equity funds used during construction	(9)	(10)	(9)
Amortization of federal investment tax credits	(2)	(3)	(3)
Section 41 tax credits	1	(3)	—
Section 45 tax credits	(9)	(9)	(5)
Domestic production activities deduction	(18)	(7)	(11)
Other differences, net	1	(3)	1
Total income tax expense	$ 231	$ 218	$ 189

The tax effects of significant temporary differences comprising Consolidated SCE&G's net deferred tax liability are as follows:

Millions of dollars	2015	2014
Deferred tax assets:		
Nondeductible accruals	$ 52	$ 47
Asset retirement obligation, including nuclear decommissioning	187	205
Unamortized investment tax credits	16	17
Deferred fuel costs	7	—
Financial instruments	2	—
Other	2	6
Total deferred tax assets	266	275
Deferred tax liabilities:		
Property, plant and equipment	$ 1,644	$ 1,623
Regulatory asset, asset retirement obligation	127	115
Deferred employee benefit plan costs	85	91
Deferred fuel costs	—	27
Regulatory asset, unrecovered plant	49	53
Regulatory asset, net loss on interest rate derivative contracts settlement	—	21
Demand side management costs	23	21
Prepayments	29	25
Other	41	23
Total deferred tax liabilities	1,998	1,999
Net deferred tax liability	$ 1,732	$ 1,724

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA and files various applicable state and local income tax returns. The IRS has completed examinations of SCANA's federal returns through 2004, and SCANA's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2014 as a result of claims discussed below in Changes to Unrecognized Tax Benefits. With few exceptions, Consolidated SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	2015	2014	2013
Unrecognized tax benefits, January 1	$ 16	$ 3	—
Gross increases-uncertain tax positions in prior period	33	—	—
Gross decreases-uncertain tax positions in prior period	(2)	—	—
Gross increases-current period uncertain tax positions	2	13	$ 3
Unrecognized tax benefits, December 31	$ 49	$ 16	$ 3

During 2013 and 2014, Consolidated SCE&G amended certain of its tax returns to claim certain tax-defined research and development deductions and credits and its related impact on domestic production activities. Consolidated SCE&G also made similar claims in filing its 2013 and 2014 returns in 2014 and 2015, respectively. In connection with these federal and state filings, Consolidated SCE&G recorded an unrecognized tax benefit of $49 million. During 2015, as the IRS' examination progressed, without resolution, Consolidated SCE&G evaluated and recorded adjustments to its unrecognized tax benefits; however, none of these changes materially affected Consolidated SCE&G's effective tax rate. If recognized, $17 million of the tax benefits would affect Consolidated SCE&G's effective tax rate. It is reasonably possible that these tax benefits will increase by an additional $7 million within the next 12 months. It is also reasonably possible that these tax benefits may decrease by $8 million within the next 12 months. No other material changes in the status of Consolidated SCE&G's tax positions have occurred through December 31, 2015.

Consolidated SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit, Consolidated SCE&G has not recorded a material amount of interest income, interest expense, or penalties associated with any uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated SCE&G recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. Consolidated SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by Consolidated SCE&G. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including Consolidated SCE&G. The Risk Management Committee, which is comprised of certain officers, including Consolidated SCE&G's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Consolidated SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, Consolidated SCE&G may use treasury rate lock or forward starting swap agreements. Pursuant to regulatory orders, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges, and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, in 2013 the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income in 2013, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G's DSM Program rider, and to apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

Consolidated SCE&G was a party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $36.4 million and $36.4 million at December 31, 2015 and 2014, respectively. Consolidated SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.235 billion and $1.085 billion at December 31, 2015 and 2014, respectively.

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments

Millions of dollars	Balance Sheet Location	Asset	Liability
As of December 31, 2015			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 1
	Other deferred credits and other liabilities		9
Total			$ 10
Not designated as hedging instruments			
Interest rate contracts	Other current assets	$ 10	
	Other deferred debits and other assets	5	
	Derivative financial instruments		$ 33
	Other deferred credits and other liabilities		22
Total		$ 15	$ 55
As of December 31, 2014			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 1
	Other deferred credits and other liabilities		8
Total			$ 9
Not designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 207
	Other deferred credits and other liabilities		17
Total			$ 224

The effect of derivative instruments on the consolidated statements of income is as follows:

Derivatives in Cash Flow Hedging Relationships		Gain (Loss) Reclassified from Deferred Accounts into Income (Effective Portion)	
Millions of dollars	Gain (Loss) Deferred in Regulatory Accounts (Effective Portion)	Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)
Year Ended December 31, 2013			
Interest rate contracts	$ 106	Interest expense	$ (3)

As of December 31, 2015, Consolidated SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.2 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gains (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income	
		Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64
Year Ended December 31, 2013			
Interest rate contracts	$ 39	Other income	$ 50

The gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2015, Consolidated SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $0.6 million as an increase to interest expense.

Credit Risk Considerations

Consolidated SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, Consolidated SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. Consolidated SCE&G uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with Consolidated SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of Consolidated SCE&G’s derivative instruments contain contingent provisions that require Consolidated SCE&G to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2015 and 2014, Consolidated SCE&G had posted $13.4 million and $107.1 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Other Current Assets on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and 2014, Consolidated SCE&G would have been required to post an additional $43.6 million and $125.9 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2015 and 2014, are $57.0 million and $233.0 million, respectively.

In addition, as of December 31, 2015 and December 31, 2014, Consolidated SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and December 31, 2014, Consolidated SCE&G could request $7.3 million and $- million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2015 and December 31, 2014 is $7.3 million and $- million, respectively.

Information related to Consolidated SCE&G's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2015						
Interest rate	$ 15	—	$ 15	$ (8)	—	$ 7

Balance sheet location	Other current assets	$ 10
	Other deferred debits and other assets	5
	Total	$ 15

As of December 31, 2014 Consolidated SCE&G had no derivative assets.

Offsetting Derivative Liabilities

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2015						
Interest rate	$ 65	—	$ 65	$ (8)	$ (13)	$ 44

Balance sheet location	Derivative financial instruments	$ 34
	Other deferred credits and other liabilities	31
	Total	$ 65

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Posted	Net Amount
As of December 31, 2014						
Interest rate	$ 233	—	$ 233	—	$ (107)	$ 126

Balance sheet location	Derivative financial instruments	$ 208
	Other deferred credits and other liabilities	25
	Total	$ 233

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Consolidated SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value Level 2 measurements were as follows:

	As of December 31, 2015	As of December 31, 2014
Millions of dollars	**Level 2**	**Level 2**
Assets-Interest rate contracts	$ 15	—
Liabilities-Interest rate contracts	65	$ 233

There were no Level 1 or Level 3 fair value measurements for either period presented and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2015 and December 31, 2014 were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 4,769.0	$ 5,129.1	$ 4,279.5	$ 5,041.9

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers regular, full-time employees hired before January 1, 2014. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full costs of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects Consolidated SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumptions based on Consolidated SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

Millions of dollars	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Benefit obligation, January 1	$ 773.7	$ 695.7	$ 204.1	$ 181.7
Service cost	19.3	16.0	4.4	3.6
Interest cost	32.2	34.1	9.4	9.4
Plan participants' contributions	—	—	1.9	1.8
Actuarial (gain) loss	(47.0)	82.7	(15.7)	18.6
Benefits paid	(54.2)	(54.8)	(10.3)	(9.6)
Amounts funded to parent	—	—	(2.1)	(1.4)
Benefit obligation, December 31	$ 724.0	$ 773.7	$ 191.7	$ 204.1

SCANA adopted new mortality tables and an improvement scale published by the Society of Actuaries in 2014, resulting in an actuarial loss for pension and other post retirement benefit obligations of approximately $22.1 million and $2.1 million, respectively, in 2014. In 2015, based on an evaluation of the mortality experience of the pension plan, SCANA adopted a custom mortality table for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $18.2 million and $2.0 million, respectively, in 2015.

The accumulated benefit obligation for pension benefits was $702.0 million at the end of 2015 and $747.6 million at the end of 2014. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Annual discount rate used to determine benefit obligation	4.68%	4.20%	4.78%	4.30%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.6 million at December 31, 2015 and by $0.9 million at December 31, 2014. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.6 million at December 31, 2015 and by $0.8 million at December 31, 2014.

Funded Status

Millions of Dollars December 31,	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Fair value of plan assets	$ 720.1	$ 783.6	—	—
Benefit obligation	724.0	773.7	$ 191.7	$ 204.1
Funded status	$ (3.9)	$ 9.9	$ (191.7)	$ (204.1)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars December 31,	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Current liability	—	—	$ (9.8)	$ (8.5)
Noncurrent asset	—	$ 9.9	—	—
Noncurrent liability	$ (3.9)	—	(181.9)	(195.6)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 2.0	$ 1.9	$ 0.7	$ 1.0
Prior service cost	—	0.1	—	—
Total	$ 2.0	$ 2.0	$ 0.7	$ 1.0

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 193.7	$ 191.9	$ 20.4	$ 35.9
Prior service cost	5.2	8.3	0.2	0.5
Total	$ 198.9	$ 200.2	$ 20.6	$ 36.4

In connection with the joint ownership of Summer Station, as of December 31, 2015 and 2014, SCE&G recorded within deferred debits $20.3 million and $17.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2015 and 2014, SCE&G also recorded within deferred debits $13.8 million and $15.1 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2015	2014
Fair value of plan assets, January 1	$ 783.6	$ 792.1
Actual return (loss) on plan assets	(9.3)	46.3
Benefits paid	(54.2)	(54.8)
Fair value of plan assets, December 31	$ 720.1	$ 783.6

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. During 2013, in connection with the amendments to the plan, SCANA adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2015 and 2014 and the target allocation for 2016 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	2016	2015	2014
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	34%
Hedge Funds	9%	11%	9%

For 2016, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2015 and 2014, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using					
Millions of dollars	Total	Level 2	Level 3	Total	Level 2	Level 3
	December 31, 2015			*December 31, 2014*		
Mutual funds	$ 496	$ 496	—	$ 566	$ 566	—
Short-term investment vehicles	12	12	—	18	18	—
US Treasury securities	20	20	—	6	6	—
Corporate debt securities	72	72	—	78	78	—
Municipals	13	13	—	14	14	—
Limited partnerships	30	30	—	29	29	—
Multi-strategy hedge funds	77	—	$ 77	73	—	$ 73
	$ 720	$ 643	$ 77	$ 784	$ 711	$ 73

At December 31, 2015, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2015 or 2014.

The pension plan values certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	2015	2014
Beginning Balance	$ 73	$ 69
Unrealized gains included in changes in net assets	4	4
Purchases, issuances, and settlements	—	—
Ending Balance	$ 77	$ 73

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from Consolidated SCE&G's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2016	$ 65.1	$ 9.8
2017	63.2	10.5
2018	64.7	11.1
2019	65.3	11.7
2020	65.8	12.3
2021 - 2025	338.3	66.1

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

Consolidated SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Service cost	$ 19.3	$ 16.0	$ 17.6	$ 4.4	$ 3.6	$ 4.6
Interest cost	32.2	34.1	32.6	9.4	9.4	8.7
Expected return on assets	(52.2)	(56.3)	(51.9)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.5	5.0	0.3	0.3	0.6
Amortization of actuarial losses	11.4	4.0	14.3	1.7	—	2.6
Curtailment	—	—	8.4	—	—	—
Net periodic benefit cost	$ 14.1	$ 1.3	$ 26.0	$ 15.8	$ 13.3	$ 16.5

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Current year actuarial (gain) loss	$ 0.2	$ 0.2	$ (0.8)	$ (0.3)	$ 0.4	$ (0.4)
Amortization of actuarial losses	(0.1)	(0.1)	(0.1)	—	—	(0.1)
Amortization of prior service cost	(0.1)	(0.1)	—	—	—	—
Total recognized in OCI	$ —	$ —	$ (0.9)	$ (0.3)	$ 0.4	$ (0.5)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

Millions of dollars	Pension Benefits 2015	Pension Benefits 2014	Pension Benefits 2013	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014	Other Postretirement Benefits 2013
Current year actuarial (gain) loss	$ 12.2	$ 87.7	$ (137.1)	$ (14.0)	$ 15.8	$ (24.4)
Amortization of actuarial losses	(10.4)	(3.5)	(12.7)	(1.5)	—	(2.2)
Amortization of prior service cost	(3.1)	(2.8)	(4.5)	(0.3)	(0.2)	(0.5)
Prior service cost (credit)	—	—	(7.7)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.1)
Total recognized in regulatory assets	$ (1.3)	$ 81.4	$ (162.0)	$ (15.8)	$ 15.6	$ (27.2)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits 2015	Pension Benefits 2014	Pension Benefits 2013	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014	Other Postretirement Benefits 2013
Discount rate	4.20%	5.03%	4.10%/5.07%	4.30%	5.19%	4.19%
Expected return on plan assets	7.50%	8.00%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.75%/3.00%	3.00%	3.75%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.40%	7.80%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 11.2	$ 0.3
Prior service cost	3.0	0.2
Total	$ 14.2	$ 0.5

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan were $21.8 million in 2015, $20.7 million in 2014 and $18.7 million in 2013 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the LTECP which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2013-2015 and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 award is based on performance over a single three-year cycle. In each performance cycle of the 2013-2015 and 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash and 80% of the awards were granted in performance shares each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For the 2015-2017 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2013-2015 performance cycle were paid in cash totaling $3.7 million at SCANA's discretion in February 2016. Cash-settled liabilities related to earlier performance cycles totaled approximately $6.3 million in 2015, $1.9 million in 2014 and $3.2 million in 2013.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $12.2 million in 2015, $12.6 million in 2014 and $5.5 million in 2013. Such fair value adjustments also resulted in capitalized compensation costs of $0.6 million in 2015, $0.6 million in 2014 and $0.5 million in 2013. At December 31, 2015 SCE&G's unrecognized compensation cost was insignificant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Consolidated SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G’s related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G’s weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2015, SCE&G’s investment in the New Units, including related transmission, totaled \$3.6 billion, for which the financing costs on \$3.2 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In October 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule. Shield building construction remains a principal focus area for SCE&G’s oversight of the project. The primary critical path for both Unit 2 and Unit 3 runs through the placement of concrete within the containment vessels, the fabrication of shield building panels, the fabrication of the air inlet and tension rings and the completion of shield building construction. For Unit 3, the critical path also runs through the setting of CA20 which is a prerequisite to concrete placement in certain areas of the nuclear island. Plans to accelerate the work needed to permit placing this concrete are underway. In addition, WEC has reached agreement on a mitigation plan to accelerate shield building panel fabrication with one of its subcontractors. Additional mitigation will be required in critical path areas to support the updated substantial completion dates described below.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The result was a revised fully integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is received.

In September 2015, the SCPSC approved an updated BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively, each subject to an 18-month contingency period. In addition, the SCPSC approved certain updated owner's costs (\$245 million) and other capital costs (\$453 million), of which \$539 million were associated with the schedule delays and other contested costs. In this proceeding, SCE&G's total projected capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) were estimated to be \$5.2 billion and \$6.8 billion, respectively. These projections included cost amounts related to the Revised, Fully-Integrated Construction Schedule for which SCE&G had not accepted responsibility and which were the subject of dispute. As such, these updated milestone schedule and projections did not reflect the resolution of negotiations. In addition, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding the above mentioned disputes, and the EPC Contract was amended. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor Corporation as a subcontracted construction manager.

Among other things, the October 2015 Amendment:

(i) resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium, in exchange for (a) an additional cost to be paid by SCE&G and Santee Cooper of $300 million (SCE&G’s 55% portion being $165 million) and an increase in the fixed component of the contract price by that amount, and (b) a credit to SCE&G and Santee Cooper of $50 million (SCE&G’s 55% portion being approximately $27 million) to be applied to the target component of the contract price,

(ii) revised the guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), and capped those aggregate liquidated damages at $463 million per New Unit (SCE&G’s 55% portion being approximately $255 million per New Unit),

(iv) provides for payment to the Consortium of a completion bonus of $275 million per New Unit (SCE&G’s 55% portion being approximately $151 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provides for development of a revised construction milestone payment schedule, with SCE&G and Santee Cooper making monthly payments of $100 million (SCE&G’s 55% portion being $55 million) for each of the first five months following effectiveness, followed by payments made based on milestones achieved, and

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project.

Under the October 2015 Amendment, SCE&G’s total estimated project costs increased by approximately $286 million over the $6.8 billion approved by the SCPSC in September 2015, bringing its total estimated gross construction cost of the project (including escalation and AFC) to approximately $7.1 billion.

The payment obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba Corporation, WEC’s parent company, reaffirmed its guaranty of WEC’s payment obligations. Based on Toshiba's current credit ratings and pursuant to the terms of the EPC Contract, SCE&G has exercised its rights to demand a payment and performance bond from WEC. Such bond will be based on estimated billings and its aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bond. In addition, the EPC Contract provides that upon the request of SCE&G, the Consortium must escrow certain intellectual property and software for SCE&G's benefit to enable completion of the New Units. SCE&G has made such a request to the Consortium.

In addition to the above, the October 2015 Amendment provided for an explicit definition of a Change in Law designed to reduce the likelihood of certain future commercial disputes, and the Consortium also acknowledged and agreed that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19. The October 2015 Amendment also established a dispute resolution board process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction milestone payment schedule referred to above. The EPC Contract was also revised to eliminate the requirement or ability to bring suit before substantial completion of the project.

Finally, the October 2015 Amendment provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G’s 55% portion being approximately $3.345 billion). This total amount to be paid would be subject to adjustment for amounts paid since June 30, 2015. Were this fixed price option to be exercised, the aggregate delay-related liquidated damages referred to in (iii) above would be capped at $338 million per unit (SCE&G's 55% portion being approximately $186 million per unit), and the completion bonus referred to in (iv) above would be $150 million per New Unit (SCE&G's 55% portion being approximately $83 million per New Unit). The exercise of this fixed price option would result in SCE&G's total estimated project costs increasing by approximately $774 million over the $6.8 billion approved by the SCPSC in September 2015, and would bring its total estimated gross construction cost (including escalation and AFC) of the project to approximately $7.6 billion.

Resolution of the disputes as described in (i) above, or in the case of the exercise of the fixed price option, would result in estimated project costs above the amounts approved by the SCPSC; however, the guaranteed substantial completion dates fall within the SCPSC approved 18-month contingency periods. SCE&G held an allowable ex parte communication briefing with the SCPSC on November 19, 2015 and, following an evaluation as to whether to exercise the fixed price option, expects to file a petition in 2016, as provided under the BLRA, for an update to the project's estimated capital cost and milestone schedule which would incorporate the impact of the October 2015 Amendment.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes through both the informal and formal procedures and currently anticipates that any costs that arise through such dispute resolution processes (including those reflected in the October 2015 Amendment described above), as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the October 2015 Amendment, which has not been approved by the SCPSC, SCE&G's currently projected cost would be approximately $750 million to $850 million for the additional 5% interest being acquired from Santee Cooper.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on the guaranteed substantial completion dates provided above, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, Consolidated SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per MWh and new natural gas units to meet 1,000 pounds carbon dioxide per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. Consolidated SCE&G is currently evaluating the rule and expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, which delayed the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The Court of Appeals remanded CSAPR, without vacating the rule, to the EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G and GENCO or their generation operations. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and SCE&G and GENCO's evaluation of the rule is ongoing. SCE&G's decision to retire certain coal-fired units (see Note 2) and its project to build the New Units along with other actions are expected to result in the SCE&G's compliance with MATS.

On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities under the MATS rule. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants. On June 29, 2015, the U.S. Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of

Appeals. The Court noted during remand that EPA has said that it is on track to issue a revised "appropriate and necessary" finding by April 15, 2016. The ruling, however, is not expected to have an impact on SCE&G or GENCO due to the aforementioned retirements and conversions. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. Consolidated SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On April 17, 2015, the EPA's final rule for CCR was published in the Federal Register and became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. Although the full effects of this rule are still being evaluated, SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. Consolidated SCE&G does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2015, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and has constructed a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until at least through 2017 and will cost an additional $18.5 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2015, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $34.8 million and are included in regulatory assets.

Claims and Litigation

Consolidated SCE&G is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on Consolidated SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

Consolidated SCE&G is obligated under various operating leases for rail cars, vehicles, office space, furniture and equipment. Leases expire at various dates through 2051. Rent expense totaled approximately $12.3 million in 2015, $12.1 million in 2014 and $13.6 million in 2013. Future minimum rental payments under such leases will be $4 million in 2016, $2 million in 2017, $1 million in 2018, $1 million in 2019, $1 million in 2020 and $17 million thereafter.

Asset Retirement Obligations

Consolidated SCE&G recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to Consolidated SCE&G's regulated utility operations. As of December 31, 2015, Consolidated SCE&G has recorded AROs of approximately $176 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $312 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	2015	2014
Beginning balance	$ 536	$ 547
Liabilities incurred	—	3
Liabilities settled	(16)	(6)
Accretion expense	23	25
Revisions in estimated cash flows	(55)	(33)
Ending Balance	$ 488	$ 536

In 2015, revisions in estimated cash flows primarily relate to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study. In 2014 such revisions primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in 2015, $30.0 million in 2014 and $33.3 million in 2013. SCE&G's payables to CGT for transportation services were $3.3 million at December 31, 2014, and SCE&G's receivables from CGT related to such transportation services were $1.2 million at December 31, 2014.

SCE&G purchases natural gas and related pipeline capacity from SEMI to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $128.5 million in 2015, $195.7 million in 2014 and $166.9 million in 2013. SCE&G's payables to SEMI for such purchases were $7.5 million and $12.6 million as of December 31, 2015 and 2014, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's total purchases from this affiliate were $233.2 million in 2015, $260.3 million in 2014 and $134.2 million in 2013. SCE&G's total sales to this affiliate were

$232.0 million in 2015, $259.0 million in 2014 and $133.6 million in 2013. SCE&G's payable to this affiliate was $12.9 million at December 31, 2015 and $27.9 million at December 31, 2014 SCE&G's receivable from this affiliate was $12.8 million at December 31, 2015 and $27.8 million at December 31, 2014.

SCANA Services, for itself and its parent company, provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems services, telecommunications services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, general administrative services and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services totaled $300.0 million in 2015, $292.2 million in 2014 and $285.6 million in 2013. Consolidated SCE&G's payables to SCANA Services for these services were $57.0 million and $47.3 million at December 31, 2015 and 2014, respectively.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs are described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Consolidated SCE&G's reportable segments follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein.

Electric Operations primarily generates, transmits, and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution purchases and sells natural gas, primarily at retail, and is regulated by the SCPSC.

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, Consolidated SCE&G does not allocate interest charges, income tax expense, earnings available to common shareholder or assets other than utility plant to its segments. Intersegment revenue and interest income were not significant. Consolidated SCE&G's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to AROs, and totals not allocated to other segments.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	876	58	—	934
Interest Expense	17	—	$ 231	248
Depreciation and Amortization	277	28	(11)	294
Segment Assets	10,883	757	3,125	14,765
Expenditures for Assets	1,087	57	(136)	1,008
Deferred Tax Assets	5	n/a	(5)	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	768	62	—	830
Interest Expense	19	—	$ 209	228
Depreciation and Amortization	300	27	(12)	315
Segment Assets	10,182	721	3,175	14,078
Expenditures for Assets	936	55	(57)	934
Deferred Tax Assets	11	n/a	(11)	—
2013				
External Revenue	$ 2,431	$ 414	—	$ 2,845
Operating Income	679	58	—	737
Interest Expense	19	—	$ 198	217
Depreciation and Amortization	294	26	(7)	313
Segment Assets	9,488	686	2,499	12,673
Expenditures for Assets	907	45	51	1,003
Deferred Tax Assets	10	n/a	(10)	—

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2015					
Total operating revenues	$ 772	$ 709	$ 806	$ 643	$ 2,930
Operating income	237	218	307	172	934
Net Income	126	111	167	76	480
Earnings Available to Common Shareholder	122	107	164	73	466
2014					
Total operating revenues	$ 859	$ 698	$ 812	$ 722	$ 3,091
Operating income	239	145	272	174	830
Net Income	126	99	157	76	458
Earnings Available to Common Shareholder	123	96	154	73	446

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2015, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCANA’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2015, SCANA's disclosure controls and procedures were effective.

Management’s Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2015, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCANA's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2015. There has been no change in SCANA’s internal controls over financial reporting during the quarter ended December 31, 2015 that has materially affected or is reasonably likely to materially affect SCANA’s internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA’s internal control system was designed by or under the supervision of SCANA’s management, including its CEO and CFO, to provide reasonable assurance to SCANA’s management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA’s management assessed the effectiveness of SCANA’s internal control over financial reporting as of December 31, 2015. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA’s management believes that, as of December 31, 2015, internal control over financial reporting is effective based on those criteria.

SCANA’s independent registered public accounting firm has issued an attestation report on SCANA’s internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2015, of the Company and our report dated February 26, 2016, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2015, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2015, SCE&G's disclosure controls and procedures were effective.

Management’s Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2015, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCE&G's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2015. There has been no change in SCE&G’s internal controls over financial reporting during the quarter ended December 31, 2015 that has materially affected or is reasonably likely to materially affect SCE&G’s internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G’s internal control system was designed by or under the supervision of SCE&G’s management, including its CEO and CFO, to provide reasonable assurance to SCE&G’s management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G’s management assessed the effectiveness of SCE&G’s internal control over financial reporting as of December 31, 2015. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).* Based on this assessment, SCE&G’s management believes that, as of December 31, 2015, internal control over financial reporting is effective based on those criteria.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 23. The other information required by ITEM 10 is incorporated herein by reference to the captions "INFORMATION ABOUT EXPERIENCE AND QUALIFICATION OF DIRECTORS AND NOMINEES," "NOMINEES FOR DIRECTORS," "CONTINUING DIRECTORS," "BOARD MEETINGS-COMMITTEES OF THE BOARD", "GOVERNANCE INFORMATION-SCANA's Code of Conduct & Ethics" and "OTHER INFORMATION-Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by ITEM 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Discussion and Analysis," Compensation Committee Report," "Summary Compensation Table," "2015 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2015 Fiscal Year-End," "2015 Option Exercises and Stock Vested," "Pension Benefits," "2015 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: Information required by ITEM 12 is incorporated herein by reference to the caption "SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

Equity securities issuable under SCANA's compensation plans at December 31, 2015 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)		(b)	(c)
Equity compensation plans approved by security holders:				
2015 Long-Term Equity Compensation Plan	157,316	(1)	n/a	4,842,684
Prior Long-Term Equity Compensation Plan	493,611	(2)	n/a	—
Non-Employee Director Compensation Plan	n/a		n/a	49,913
Equity compensation plans not approved by security holders	n/a		n/a	n/a
Total	650,927		n/a	4,892,597

(1) Represents unearned non-vested performance share awards from the 2015-2017 performance period assuming a target level payout.
(2) Represents earned non-vested performance share awards from the 2014-2016 performance period at achieved levels and unearned non-vested performance share awards from the 2014-2016 performance period assuming a target level payout. Also includes 226,902 performance shares related to vested grants from the 2013-2015 performance period which were settled in cash rather than shares in February 2016. The remaining award amount of 266,709 will be 128,132 higher if maximum level payout is earned for the 2014-2016 performance period.

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: The information required by ITEM 13 is incorporated herein by reference to the captions “RELATED PARTY TRANSACTIONS” and “GOVERNANCE INFORMATION - Director Independence” in SCANA’s definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA: The information required by ITEM 14 is incorporated herein by reference to “PROPOSAL 2-APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM” in SCANA’s definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities and Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm’s Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to SCE&G and its consolidated affiliates for the fiscal years ended December 31, 2015 and 2014 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2015	2014
Audit Fees (1)	$ 2,032,222	$ 1,977,658
Audit-Related Fees (2)	114,832	123,107
Total Fees	$ 2,147,054	$ 2,100,765

(1) Fees for audit services billed in 2015 and 2014 consisted of audits of annual financial statements, comfort letters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under ITEM 8 herein.

The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under ITEM 8 herein.

The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA’s employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts
(in millions)

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:					
Reserves deducted from related assets on the balance sheet:					
Uncollectible accounts					
2015	$ 7	$ 12	—	$ 14	$ 5
2014	6	16	—	15	7
2013	7	13	—	14	6
Reserves other than those deducted from assets on the balance sheet:					
Reserve for injuries and damages					
2015	$ 5	$ 11	—	$ 10	$ 6
2014	6	7	—	8	5
2013	6	4	—	4	6
SCE&G:					
Reserves deducted from related assets on the balance sheet:					
Uncollectible accounts					
2015	$ 4	$ 6	—	$ 7	$ 3
2014	3	8	—	7	4
2013	3	7	—	7	3
Reserves other than those deducted from assets on the balance sheet:					
Reserve for injuries and damages					
2015	$ 3	$ 11	—	$ 9	$ 5
2014	5	1	—	3	3
2013	5	3	—	3	5

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

DATE: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Controller

(Principal Accounting Officer)

Other Directors*:

G. E. Aliff	L. M. Miller
J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
S. A. Decker	H. C. Stowe
D. M. Hagood	A. Trujillo
J. M. Micali	

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 26, 2016

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director

DATE: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison
J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV
J. E. Swan, IV
Controller
(Principal Accounting Officer)

Other Directors*:

G. E. Aliff	L. M. Miller
J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
S. A. Decker	H. C. Stowe
D. M. Hagood	A. Trujillo
J. M. Micali	

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 26, 2016

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	SCE&G	Description
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of February 19, 2009 (Filed as Exhibit 4.04 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein)
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein)
4.03	X		First Supplemental Indenture dated as of November 1, 2009 to Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 99.01 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.04		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein)
4.05		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein)
4.06		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein)
4.07		X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)
10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2008 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.03	X	X	Amendment to EPC Contract referred to in Exhibit 10.01 dated October 27, 2015 (Filed as Exhibit 10.05 to Form 10-Q for the quarter ended September 30, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)

*10.04	X	X	SCANA Executive Deferred Compensation Plan (including amendments through November 25, 2014) (Filed as Exhibit 10.03 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.05	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.06	X	X	SCANA Director Compensation and Deferral Plan (including amendments through November 30, 2014) (Filed as Exhibit 10.05 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.07	X	X	SCANA Long-Term Equity Compensation Plan as amended and restated (including amendments through December 31, 2009) (Filed as Exhibit 99.06 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.08	X	X	SCANA Long-Term Equity Compensation Plan effective February 19, 2015 (Filed as Exhibit 4.05 to Registration Statement No. 333-204218 and incorporated by reference herein)
*10.09	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.10	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.11	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.12	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.13		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.14	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.15	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
10.16	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A., as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.17	X	X	Amended and Restated Three-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.18	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.19	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
*10.20	X		General Release and Severance Agreement between SCANA and George J. Bullwinkel, Jr. (Filed as Exhibit 10.02 to Form 10-Q for the quarter ended March 31, 2015 and incorporated by reference herein)
*10.21	X		Independent Contractor Agreement SCANA Services, Inc. and George J. Bullwinkel, Jr. (Filed as Exhibit 10.03 to Form 10-Q for the quarter ended March 31, 2015 and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith under the heading “Corporate Structure and Segments of Business” in PART I, ITEM I of this Form 10-K and incorporated by reference herein)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02		X	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS**	X	X	XBRL Instance Document
101. SCH**	X	X	XBRL Taxonomy Extension Schema
101. CAL**	X	X	XBRL Taxonomy Extension Calculation Linkbase
101. DEF**	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB**	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE**	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Management Contract or Compensatory Plan or Arrangement

** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

Exhibit 12.01

COMPUTATION OF RATIOS
December 31, 2015

BOND RATIO

SCANA and SCE&G:

Dollars in Millions Year Ended December 31, 2015		
Net earnings as defined in SCE&G's bond indenture dated April 1, 1993 (Mortgage)		$ 1,214.1
Divide by annualized interest charges on:		
Bonds outstanding under the Mortgage	$ 235.0	
Total annualized interest charges	235.0	
Bond Ratio		5.17

RATIO OF EARNINGS TO FIXED CHARGES

Dollars in Millions	SCANA					SCE&G				
Years Ended December 31,	2015	2014	2013	2012	2011	2015	2014	2013	2012	2011
Fixed Charges as defined:										
Interest on debt	$327.8	$318.2	$305.9	$301.3	$287.0	$258.4	$237.6	$226.4	$217.4	$207.8
Amortization of debt premium, discount and expense (net)	4.7	9.7	5.3	4.9	4.8	3.7	4.4	4.2	3.9	3.9
Interest component on rentals	3.7	4.1	4.9	4.9	5.2	4.1	4.0	4.5	3.2	3.6
Total Fixed Charges (A)	$336.2	$332.0	$316.1	$311.1	$297.0	$266.2	$246.0	$235.1	$224.5	$215.3
Earnings as defined:										
Pretax income from continuing operations	$1,138.4	$786.0	$693.8	$601.6	$555.6	$711.0	$676.0	$579.7	$509.5	$456.5
Total fixed charges above	336.2	332.0	316.1	311.1	297.0	266.2	246.0	235.1	224.5	215.3
Pretax equity in (earnings) losses of investees	0.8	(1.4)	(3.2)	(3.3)	(2.9)	5.0	5.3	3.5	3.8	2.3
Cash distributions from equity investees	4.0	7.4	9.6	3.3	3.6	-	-	-	-	-
Total Earnings (B)	$1,479.4	$1,124.0	$1,016.3	$912.7	$853.3	$982.2	$927.3	$818.3	$737.8	$674.1
Ratio of Earnings to Fixed Charges (B/A)	4.40	3.39	3.22	2.93	2.87	3.69	3.77	3.48	3.29	3.13

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-174796, 333-191691 and 333-204218 on Form S-8 and Registration Statement Nos. 333-191756 and 333-206629 on Form S-3 of our reports dated February 26, 2016, relating to the consolidated financial statements and financial statement schedule of SCANA Corporation and subsidiaries (the “Company”), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2015.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-206629-01 on Form S-3 of our report dated February 26, 2016, relating to the consolidated financial statements and financial statement schedule of South Carolina Electric & Gas Company and affiliates appearing in this Annual Report on Form 10-K of South Carolina Electric & Gas Company for the year ended December 31, 2015.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

Exhibit 24.01

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of SCANA Corporation ("SCANA"), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCANA's fiscal year ended December 31, 2015, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 18th day of February 2016.

/s/G. E. Aliff	/s/J. A. Bennett
G. E. Aliff Director	J. A. Bennett Director
/s/J. F. A. V. Cecil	/s/S. A. Decker
J. F. A. V. Cecil Director	S. A. Decker Director
/s/D. M. Hagood	/s/K. B. Marsh
D. M. Hagood Director	K. B. Marsh Director
/s/J. M. Micali	/s/L. M. Miller
J. M. Micali Director	L. M. Miller Director
/s/J. W. Roquemore	/s/M. K. Sloan
J. W. Roquemore Director	M. K. Sloan Director
/s/H. C. Stowe	/s/A. Trujillo
H. C. Stowe Director	A. Trujillo Director

Exhibit 24.02

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of South Carolina Electric & Gas Company ("SCE&G"), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCE&G's fiscal year ended December 31, 2015, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 18th day of February 2016.

/s/G. E. Aliff	/s/J. A. Bennett
G. E. Aliff Director	J. A. Bennett Director
/s/J. F. A. V. Cecil	/s/S. A. Decker
J. F. A. V. Cecil Director	S. A. Decker Director
/s/D. M. Hagood	/s/K. B. Marsh
D. M. Hagood Director	K. B. Marsh Director
/s/J. M. Micali	/s/L. M. Miller
J. M. Micali Director	L. M. Miller Director
/s/J. W. Roquemore	/s/M. K. Sloan
J. W. Roquemore Director	M. K. Sloan Director
/s/H. C. Stowe	/s/A. Trujillo
H. C. Stowe Director	A. Trujillo Director

Exhibit 31.01

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 26, 2016

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board, President,
Chief Executive Officer and Chief Operating Officer

Exhibit 31.02

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 26, 2016

/s/Jimmy E. Addison
Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 31.03

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 26, 2016

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board and Chief Executive Officer

Exhibit 31.04

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 26, 2016

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 32.01

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the “Company”) on Form 10-K for the year ended December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 26, 2016

/s/Kevin B. Marsh	/s/Jimmy E. Addison
Kevin B. Marsh	Jimmy E. Addison
Chairman of the Board, President, Chief Executive Officer and Chief Operating Officer	Executive Vice President and Chief Financial Officer

Exhibit 32.02

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of South Carolina Electric & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 26, 2016

/s/Kevin B. Marsh	/s/Jimmy E. Addison
Kevin B. Marsh	Jimmy E. Addison
Chairman of the Board and Chief Executive Officer	Executive Vice President and Chief Financial Officer

FORM 10-K

SOUTH CAROLINA ELECTRIC & GAS CO - SCG

Filed: February 28, 2014 (period: December 31, 2013)

Annual report with a comprehensive overview of the company

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2013

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	**SCANA Corporation** (a South Carolina corporation)	57-0784499
1-3375	**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	57-0248695

Securities registered pursuant to Section 12(b) of the Act:
SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange
2009 Series A 7.70% Enhanced Junior Subordinated Notes, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $6.85 billion at June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $49.10 per share. South Carolina Electric & Gas Company is a wholly -owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 20, 2014
SCANA Corporation	Without Par Value	141,144,841
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Specified sections of SCANA Corporation's Proxy Statement, in connection with its 2014 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other company.

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;

(2) regulatory actions, particularly changes in rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;

(3) current and future litigation;

(4) changes in the economy, especially in areas served by subsidiaries of SCANA;

(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;

(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;

(7) the loss of sales to distributed generation, such as solar photovoltaic systems;

(8) growth opportunities for SCANA's regulated and diversified subsidiaries;

(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;

(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA's subsidiaries;

(11) changes in SCANA's or its subsidiaries' accounting rules and accounting policies;

(12) payment and performance by counterparties and customers as contracted and when due;

(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission;

(14) maintaining creditworthy joint owners for SCE&G's new nuclear generation project;

(15) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon prices, for our construction program, operations and maintenance;

(16) the results of efforts to ensure the physical and cyber security of key assets and processes;

(17) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;

(18) the availability of skilled and experienced human resources to properly manage, operate, and grow the Company's businesses;

(19) labor disputes;

(20) performance of SCANA's pension plan assets;

(21) changes in taxes;

(22) inflation or deflation;

(23) compliance with regulations;

(24) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and

(25) the other risks and uncertainties described from time to time in the periodic reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of Westinghouse Electric Company LLC and Stone and Webster, Inc., a subsidiary of Chicago Bridge & Iron Company N. V.
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker
CWA	Clean Water Act
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DSM Programs	Demand Side Management Programs
EIZ Credits	South Carolina Capital Investment Tax Credits (formerly known as Economic Impact Zone Income Tax Credits)
ELG Rule	New federal effluent limitation guidelines for steam electric generating units
Energy Marketing	The divisions of SEMI, excluding SCANA Energy
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
eWNA	Pilot Electric WNA
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
JEDA	South Carolina Jobs-Economic Development Authority
KVA	Kilovolt ampere
kWh	Kilowatt-hour

TERM	MEANING
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LNG	Liquefied Natural Gas

LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF or MMCF	Thousand Cubic Feet or Million Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NASDAQ	The NASDAQ Stock Market, Inc.
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PRP	Potentially Responsible Party
PSNC Energy	Public Service Company of North Carolina, Incorporated
RCC	Replacement Capital Covenant
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	A division of SEMI which markets natural gas in Georgia
SCE&G	South Carolina Electric & Gas Company
SCEUC	South Carolina Energy Users Committee
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
SERC	SERC Reliability Corporation
Southern Natural	Southern Natural Gas Company
Summer Station	V. C. Summer Nuclear Station

TERM	MEANING
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
Westinghouse	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

CORPORATE STRUCTURE AND ORGANIZATION

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA holds directly all of the capital stock of the following subsidiaries, each of which is incorporated in South Carolina.

SCE&G	Engaged in the generation, transmission, distribution and sale of electricity to retail and wholesale customers and the purchase, sale and transportation of natural gas to retail customers
GENCO	Owns Williams Station and sells electricity solely to SCE&G
Fuel Company	Acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances
PSNC Energy	Purchases, sells and transports natural gas to retail customers
CGT	Transports natural gas in South Carolina and southeastern Georgia
SCI	Provides fiber optic communications, ethernet services and data center facilities and builds, manages and leases communications towers in South Carolina, North Carolina and Georgia
SEMI	Markets natural gas, primarily in the Southeast, and provides energy-related risk management services. SCANA Energy, a division of SEMI, markets natural gas in Georgia's retail market.
ServiceCare, Inc.	Provides service contracts on home appliances and heating and air conditioning units
SCANA Services, Inc.	Provides administrative, management and other services to SCANA's subsidiaries and business units

SCANA owns one other energy-related company that is insignificant and being liquidated.

SCANA and its subsidiaries had full-time, permanent employees as of February 20, 2014 and 2013 of 5,989 and 5,842, respectively.

INVESTOR INFORMATION

SCANA's and SCE&G's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at *www.scana.com* (which is not intended as an active hyperlink) as soon as reasonably practicable after these reports are filed or furnished. Information on SCANA's website is not part of this or any other report filed with or furnished to the SEC.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's new nuclear project on SCANA's website at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC). On SCANA's homepage, there is a yellow box containing a link to the New Nuclear Development section of the website. That section in turn contains a yellow box with a link to recent project news and updates. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public, and investors, media and others interested in SCE&G's new nuclear project are encouraged to review this information.

SEGMENTS OF BUSINESS

For information with respect to major segments of business, see Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and the consolidated financial statements for SCANA and SCE&G (Note 12). All such information is incorporated herein by reference.

SCANA does not directly own or operate any significant physical properties. SCANA, through its subsidiaries, is engaged in the functionally distinct operations described below.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 678,000 customers and the purchase, sale and transportation of natural gas to approximately 329,000 customers (each as of December 31, 2013). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 22,600 square miles. More than 3.2 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products and fabricated metal products.

PSNC Energy purchases, sells and transports natural gas to approximately 509,000 residential, commercial and industrial customers (as of December 31, 2013). PSNC Energy serves 28 franchised counties covering 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

CGT operates as an open access, transportation-only interstate pipeline company regulated by FERC. CGT operates in southeastern Georgia and in South Carolina and has interconnections with Southern Natural at Port Wentworth, Georgia and with Southern LNG, Inc. at Elba Island, near Savannah, Georgia. CGT also has interconnections with Southern Natural in Aiken County, South Carolina, and with Transco in Cherokee and Spartanburg counties, South Carolina. CGT's customers include SCE&G (which uses natural gas for electricity generation and for gas distribution to retail customers), SEMI (which markets natural gas to industrial and sale for resale customers, primarily in the Southeast), municipalities, county gas authorities, federal and state agencies, marketers, power generators and industrial customers primarily engaged in the manufacturing or processing of ceramics, paper, metal, and textiles.

Nonregulated Businesses

SEMI markets natural gas primarily in the southeast and provides energy-related risk management services. SCANA Energy, a division of SEMI, sells natural gas to approximately 454,000 customers (as of December 31, 2013, and includes approximately 68,000 customers in its regulated division) in Georgia's natural gas market. In third quarter 2013, SCANA Energy's contract to serve as Georgia's regulated provider of natural gas was renewed by the GPSC through August 31, 2015. SCANA Energy's total customer base represents an approximately 30% share of the approximately 1.5 million customers in Georgia's deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in Georgia.

SCI owns and operates a 1,125 mile fiber optic telecommunications network and ethernet network and data center facilities in South Carolina. Through a joint venture, SCI has an interest in an additional 2,280 miles of fiber in South Carolina, North Carolina and Georgia. SCI also provides tower site construction, management and rental services and sells towers in South Carolina and North Carolina. SCI leases fiber optic capacity, data center space and tower space to certain affiliates at market rates.

The preceding Corporate Structure and Organization section describes other regulated and nonregulated businesses owned by SCANA.

COMPETITION

For a discussion of the impact of competition, see the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

CAPITAL REQUIREMENTS

SCANA's regulated subsidiaries, including SCE&G, require cash to fund operations, construction programs and dividend payments to SCANA. SCANA's nonregulated subsidiaries require cash to fund operations and dividend payments to SCANA. To replace existing plant investment and to expand to meet future demand for electricity and gas, SCANA's regulated subsidiaries must attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their construction programs, rate increases will be sought.

The future financial position and results of operations of the regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief, when requested.

For a discussion of various rate matters and their impact on capital requirements, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and Note 2 to the consolidated financial statements for SCANA and SCE&G.

During the period 2014-2016, SCANA and SCE&G expect to meet capital requirements through internally generated funds, issuance of equity and short-term and long-term borrowings. SCANA and SCE&G expect that they have or can obtain adequate sources of financing to meet their projected cash requirements for the next 12 months and for the foreseeable future.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2013, were as follows:

December 31,	2013	2012	2011	2010	2009
SCANA	3.22	2.93	2.87	2.92	2.84
SCE&G	3.48	3.29	3.13	3.18	3.25

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity and margins earned from the sale of electricity by customer classification as percentages of electric revenues for 2012 and 2013 were as follows:

	Sales		Margins	
Customer Classification	**2012**	**2013**	**2012**	**2013**
Residential	43%	44%	50%	50%
Commercial	32%	33%	33%	33%
Industrial	17%	18%	13%	14%
Sales for resale	6%	2%	2%	1%
Other	2%	3%	2%	2%
Total	100%	100%	100%	100%

Sales for resale include sales to three municipalities and one electric cooperative. Short-term system sales were not significant for any period presented.

During 2013 SCE&G experienced a net increase of approximately 8,000 electric customers (growth rate of 1.2%), increasing its total electric customers to approximately 678,000 at year end.

For the period 2014-2016, SCE&G projects total territorial kWh sales of electricity to increase 0.6% annually (assuming normal weather), total retail sales growth of 0.6% annually (assuming normal weather), total electric customer base to increase 1.8% annually and territorial peak load (summer, in MW) to increase 1.9% annually. SCE&G projects a retail kWh sales decrease of approximately 0.2% and customer growth of 1.1% from 2013 to 2014. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%, however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a Unit Power Sales Agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system, which extends over a large part of the central, southern and southwestern portions of South Carolina, interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., Santee Cooper, Georgia Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. SERC is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America. For a discussion of the impact certain legislative and regulatory initiatives may have on SCE&G's transmission system, see Electric Operations within the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) for the years 2011-2013 follow:

	Cost of Fuel Used		
	2011	2012	2013
Per MMBTU:			
Nuclear	$ 0.88	$ 0.94	$ 1.11
Coal	4.47	4.49	4.28
Natural Gas	4.86	3.71	4.63
All Fuels (weighted average)	3.80	3.56	3.53
Per Ton: Coal	109.91	111.72	104.63
Per MCF: Gas	5.01	3.80	4.69

The sources and percentages of total MWh generation by each category of fuel for the years 2011-2013 and the estimates for the years 2014-2016 follow:

	% of Total MWh Generated					
	Actual			Estimated		
	2011	2012	2013	2014	2015	2016
Coal	50%	50%	45%	50%	49%	45%
Nuclear	19%	19%	24%	21%	21%	24%
Hydro	3%	3%	4%	4%	4%	4%
Natural Gas & Oil	28%	28%	26%	24%	25%	26%
Biomass	—	—	1%	1%	1%	1%
Total	100%	100%	100%	100%	100%	100%

In 2013, the Company used coal to generate electricity at six fossil fuel-fired plants, including its cogeneration facility located in Charleston, South Carolina. Unit trains and, in some cases, trucks and barges delivered coal to these plants. SCE&G completed the retirement of one of these plants (comprised of three units) in 2012 and 2013 and intends to retire certain other coal-fired generating units by 2018, subject to future developments in environmental regulations, among other matters. One of the units to be retired by 2018 was fueled with coal prior to 2013, but is expected to be fueled exclusively with natural gas until its retirement.

Coal is primarily obtained through long-term supply contracts. Long-term contracts exist with suppliers located in eastern Kentucky, Tennessee and West Virginia. These contracts provide for approximately 2.8 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2016. Spot market purchases may occur when needed or when prices are believed to be favorable.

SCANA and SCE&G believe that SCE&G's operations comply with all applicable regulations relating to the discharge of sulfur dioxide and nitrogen oxide. See additional discussion at Environmental Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G, for itself and as agent for Santee Cooper, and Westinghouse are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G has to supply enriched product to Westinghouse and Westinghouse will supply nuclear fuel assemblies for Summer Station Unit 1 and the New Units. Westinghouse will be SCE&G's exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Summer Station Unit 1 and the New Units through 2033. SCE&G is dependent upon Westinghouse for providing fuel assemblies for the new AP1000 reactors in the New Units in the current and anticipated future absence of other commercially viable sources.

The Consortium currently provides maintenance and engineering support to Summer Station Unit 1 under a services alliance agreement. Although SCE&G has provided the Consortium with notice of its election to terminate the existing agreement, it is anticipated that SCE&G will enter into new agreements to provide similar support services to Summer Station Unit 1 and to the New Units upon their completion and commencement of commercial operation. Those new agreements may, but will not necessarily, be between SCE&G and the Consortium.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of its nuclear generating units.

SCE&G can store spent nuclear fuel on-site until at least 2017 and has commenced construction of a dry cask storage facility to accommodate the spent fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available. In addition, Summer Station Unit 1 has sufficient on-site storage capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see *Hazardous and Solid Wastes* within the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported for 2012 and 2013 were as follows:

	SCANA		**SCE&G**	
Customer Classification	**2012**	**2013**	**2012**	**2013**
Residential	54.7%	55.6%	44.3%	43.5%
Commercial	26.1%	26.0%	27.5%	27.4%
Industrial	11.8%	12.5%	22.3%	25.6%
Transportation Gas	7.4%	5.9%	5.9%	3.5%
Total	100.0%	100.0%	100.0%	100.0%

For the three-year period 2014-2016, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.4% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.1%, commercial of 0.8% and industrial of 0.8%.

For the three-year period 2014-2016, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 0.8% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 1.0%, commercial of 0.6% and industrial of 1.0%.

For the three-year period 2014-2016, SCANA's and SCE&G's total consolidated regulated natural gas customer base is projected to increase annually 2.3% and 1.9%, respectively. During 2013 SCANA recorded a net increase of approximately 18,000 regulated gas customers (growth rate of 2.2%), increasing its regulated gas customers to approximately 837,000. Of this increase, SCE&G recorded a net increase of approximately 7,000 gas customers (growth rate of 2.1%), increasing its total gas customers to approximately 329,000 (as of December 31, 2013).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost, Supply and Curtailment Plans

SCE&G purchases natural gas under contracts with producers and marketers in both the spot and long-term markets. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2014 and 2018), Transco (expiring in 2017) and CGT (expiring in 2014, 2018, 2023 and 2026). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 222,404 MMBTU from Southern Natural, 64,652 MMBTU from Transco and 425,929 MMBTU from CGT. Additional natural gas volumes may be delivered to SCE&G's system as capacity is available through interruptible transportation.

The daily volume of gas that SEMI is entitled to transport under service agreements with CGT (expiring in 2016, 2017 and 2023) on a firm basis is 82,615 MMBTU.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $5.35 per MCF during 2013 and $4.73 per MCF during 2012.

SCE&G was allocated 5,382 MMCF of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 4,039 MMCF of gas were in storage on December 31, 2013. To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G supplements its supplies of natural gas with two LNG liquefaction and storage facilities. The LNG plants are capable of storing the liquefied equivalent of 1,880 MMCF of natural gas. Approximately 1,635 MMCF (liquefied equivalent) of gas were in storage on December 31, 2013.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2032. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 610,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $5.13 per MMBTU during 2013 compared to $4.65 per MMBTU during 2012.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, Transco and Spectra Energy provide for storage capacity of approximately 13,000 MMCF. Approximately 10,000 MMCF of gas were in storage under these agreements at December 31, 2013. In addition, PSNC Energy's LNG facility can store the liquefied equivalent of 1,000 MMCF of natural gas with regasification capability of approximately 100 MMCF per day. Approximately 900 MMCF (liquefied equivalent) of gas were in storage at December 31, 2013. LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG provide for 1,300 MMCF (liquefied equivalent) of storage space. Approximately 1,100 MMCF (liquefied equivalent) were in storage under these agreements at December 31, 2013.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SEMI markets natural gas and provides energy-related risk management services primarily in the Southeast. In addition, SCANA Energy, a division of SEMI, markets natural gas to approximately 454,000 customers (as of December 31, 2013) in Georgia's natural gas market. SCANA Energy's total customer base represents an approximate 30% share of the approximately 1.5 million customers in Georgia's deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements for SCANA and SCE&G.

REGULATION

For a discussion of legislative and regulatory initiatives being implemented that will affect SCE&G's transmission system, see Electric Operations within the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

For a discussion of the regulatory jurisdictions to which SCANA and its subsidiaries are subject, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	License Expiration
Saluda (Lake Murray)	2014
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

SCE&G is presently operating the Saluda hydroelectric project under an annual license (scheduled to expire in August) while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, or may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and Note 2 to the consolidated financial statements for SCANA and SCE&G.

Prior to the first billing cycle of January 2014, SCE&G's retail electric rates for its residential and certain small commercial customers included an eWNA approved by the SCPSC, which largely mitigated the impact of weather on electric margins. In connection with a December 2013 SCPSC order, SCE&G discontinued the eWNA.

SCE&G's retail electric rates include certain costs associated with its DSM Programs as authorized by the SCPSC. More specifically, these rates include the costs and lost net margin revenue associated with DSM Programs, along with an incentive for investing in such programs.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11%.

In May 2011 and in November 2012, the SCPSC approved updated capital cost schedules sought by SCE&G that, among other matters, incorporated then-identifiable additional capital costs and revised substantial completion dates for the New Units, and included amounts to resolve certain claims. Details of these SCPSC approvals are further described in Notes 2 and 10 to the consolidated financial statements for SCANA and SCE&G.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates and authorized SCE&G an allowed return on common equity of 10.25% (related to non-BLRA expenditures). The SCPSC also approved a mid-period reduction to the cost of fuel component in rates, as well as a reduction in the DSM Programs component rider to retail rates, among other things. See Note 2 to the consolidated financial statements for SCANA and SCE&G for additional details.

SCE&G's gas rate schedules for its residential, small commercial and small industrial customers include a WNA approved by the SCPSC, which is in effect for bills rendered for billing cycles in November through April. The WNA increases tariff rates if weather is warmer than normal and decreases rates if weather is colder than normal. The WNA does not change the seasonality of gas revenues, but reduces fluctuations in revenues and earnings caused by abnormal weather.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows PSNC Energy to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Fuel Cost Recovery Procedures

The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions. The definition also includes the cost of emission allowances used for sulfur dioxide, nitrogen oxide, mercury and particulates. SCE&G may request a formal proceeding concerning its fuel costs at any time. SCPSC proceedings related to SCE&G's cost of fuel component are described in Note 2 to the consolidated financial statements for SCANA and SCE&G.

SCE&G's natural gas tariffs include a PGA clause that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average. SCPSC proceedings related to SCE&G's natural gas tariffs are described in Note 2 to the consolidated financial statements for SCANA and SCE&G.

PSNC Energy is subject to a Rider D rate mechanism which allows it to recover from customers all prudently incurred gas costs, including gas costs that were uncollectible from certain customers. The Rider D rate mechanism also allows it to recover, in any manner authorized by the NCUC, losses on negotiated gas and transportation sales.

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be adjusted periodically to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption. NCUC proceedings related to PSNC Energy's rates are described in Note 2 to the consolidated financial statements for SCANA.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of these regulations and standards upon existing and proposed operations cannot be predicted. For a more complete discussion of how these regulations and standards impact SCANA and SCE&G, see the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements for SCANA and SCE&G.

OTHER MATTERS

For a discussion of SCE&G's insurance coverage for Summer Station Unit 1 and the New Units, see Note 10 to the consolidated financial statements for SCANA and SCE&G.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to SCANA and its subsidiaries, and where indicated the risk factors also relate to SCE&G and its consolidated affiliates.

Commodity price changes, delays and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs) and availability. Any such changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to require the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial position.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternative forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers unable to switch to alternative fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction for environmental compliance and its construction of the New Units and associated transmission, are significant and are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of the projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in energy generation and in other internal infrastructure projects, including projects for environmental compliance. For example, SCE&G and Santee Cooper have agreed to jointly own, contract the design and construction of, and operate the New Units, which will be two 1,250 MW (1,117 MW, net) nuclear units at SCE&G's Summer Station, in pursuit of which they have committed and are continuing to commit significant resources. In addition, construction of significant new transmission infrastructure is necessary to support the New Units and is under way as an integral part of the project. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and timeframes may be affected by many variables, such as the regulatory and legal processes associated with securing permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness, and unforeseen difficulties meeting critical regulatory requirements. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects (including new baseload generation) as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, new or enhanced environmental requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. Some of the foregoing issues have been experienced in the construction of the New Units. A discussion of certain of those matters can be found under New Nuclear Construction Matters in Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for SCANA and SCE&G.

Should the construction of the New Units materially and adversely deviate from the schedules, estimates, and projections submitted to and approved by the SCPSC pursuant to the BLRA, the SCPSC could disallow the additional capital costs that result from the deviations to the extent that it is deemed that the Company's failure to anticipate or avoid the deviation, or to minimize the resulting expenses, was imprudent, considering the information available at the time. Depending upon the magnitude of any such disallowed capital costs, the Company could be moved to evaluate the prudency of continuation, adjustment to, or termination of the New Units project.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to the risk that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, new joint owners cannot be secured at equivalent financial terms, or changes in the joint ownership make-up will increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows and financial condition may be adversely affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e. natural gas) market risk. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract.

The Company strives to manage commodity price exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be diminished.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this new legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers, major swap participants and financial institutions, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers, major swap participants or financial institutions, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Moreover, the Company retains reporting responsibility for certain types of swaps, such as the annual reporting of trade options. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental commissions, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our business. In addition to many other aspects of our business, these requirements impact the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas transmission systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's or Consolidated SCE&G's businesses.

Furthermore, changes in or uncertainty in monetary, fiscal, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G could be adversely impacted by changes in tax policy, such as the loss of Production Tax Credits related to the construction of the New Units.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects, DSM Programs results and/or increases in operating costs may lead to requests for regulatory relief, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits.

SCE&G's electric operations in South Carolina and the Company's gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. The Company's interstate gas pipeline, SCE&G's electric transmission system and Consolidated SCE&G's generating facilities are subject to extensive regulation and oversight from the FERC, NRC and SCPSC. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as market conditions evolve. Although we believe that we have constructive relationships with the regulators, our ability to obtain rate treatment that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing nitrogen oxide, sulfur dioxide, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On September 20, 2013, the EPA re-proposed NSPS for emissions of carbon dioxide from newly constructed fossil fuel-fired electric generating units. Standards, regulations, or guidelines are also expected for existing units by June 1, 2014, to be made final no later than June 1, 2015. A number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none have yet been enacted. On February 16, 2012, the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. The EPA has proposed requirements for cooling water intake structures to meet the best technology available, and the EPA presently is drafting a final rule regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA has proposed new standards under the CWA governing effluent limitation guidelines for electric generating units.

Compliance with these environmental laws and regulations requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as the clean-up of MGP sites or additional emission allowances) or require us to incur additional capital expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our industry, our business and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. Some states already have them, though currently South Carolina does not. Such standards could direct us to build or otherwise acquire generating capacity derived from renewable/alternative energy sources (generally, renewable energy such as biomass, solar, wind and tidal, and excluding fossil fuels, nuclear or hydro facilities). Such renewable/alternative energy may not be readily available in our service territories, if at all, and could be extremely costly to build, acquire, and operate. Resulting increases in the price of electricity to recover the cost of these types of generation, if approved by regulatory commissions, could result in lower usage of electricity by our customers. Although we cannot predict whether such standards will be adopted at the federal level or in South Carolina or their specifics if adopted, compliance with such potential portfolio standards could significantly impact our industry, our capital expenditures, and our results of operations and financial position.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In effecting compliance with MATS, SCE&G announced in 2012 that six of its oldest and smallest coal-fired units would be taken off-line or temporarily switched from coal to natural gas prior to closure in 2018. One of these units was retired in late 2012. Two other of these units were retired in late 2013.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company’s and Consolidated SCE&G’s business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company’s and Consolidated SCE&G’s ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our business. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and its actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA’s pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company’s and Consolidated SCE&G’s results of operations, cash flows and financial position, including its shareholders’ equity.

A downgrade in the credit rating of SCANA or any of SCANA’s subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies rate SCANA’s long-term senior unsecured debt, SCE&G’s long-term senior secured debt, and the long-term senior unsecured debt of PSNC Energy as investment grade. In addition, ratings agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. If these rating agencies were to lower the outlook or downgrade any of these ratings, particularly to below investment grade, borrowing cost on new issuances would increase, which would diminish financial results, and the potential pool of investors and funding sources could decrease.

In 2011, one rating agency downgraded both the short-term and senior unsecured long-term debt of SCANA. In 2013, another rating agency revised the outlook for SCANA and its subsidiaries to negative from stable. These downgrades and lowered outlook have increased the short-term borrowing rates of SCANA and may have the effect of increasing the long-term borrowing rates of SCANA and SCE&G. Although access to the short-term market has not been adversely impacted, this could change under different market conditions.

SCANA's leverage ratio of long- and short-term debt to capital was approximately 56% at December 31, 2013. SCANA has publicly announced its desire to maintain its leverage ratio between 54% and 57%, but SCANA's ability to do so depends on a number of factors. In the future, if SCANA is not able to maintain its leverage ratio within the desired range, the Company's debt ratings may be affected, it may be required to pay higher interest rates on its long- and short-term indebtedness, and its ability to access the capital markets may be impaired.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and received lower prices for natural gas in deregulated markets when weather conditions have been milder than normal, and as a consequence earned less income from those operations. During 2010, the SCPSC approved SCE&G's implementation of an eWNA on a pilot basis; it was discontinued at the end of 2013. Mild weather in the future could diminish the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as electromagnetic events and the 2011 earthquake and tsunami in Japan) or man-made mishaps (such as the San Bruno, California natural gas transmission pipeline failure, the Kingston, Tennessee coal ash pond failure, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could indirectly impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial position, operating expenses, and cash flows.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via a RTO/ISO (Regional Transmission Organization/Independent System Operator) is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should a RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new delivery transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets would be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems. As a result of federal and state subsidies and potential regulations allowing third-party retail sales, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and slow growth, potentially causing higher rates to customers.

The Company and SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Some economic sectors important to our customer base may be particularly affected. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally or legislative or regulatory actions. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company’s and SCE&G’s products and adversely affect sales, sales growth, and customer usage patterns.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be significantly harmed.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company’s or Consolidated SCE&G’s operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission line failure, information systems failure or security breach, the effects of drought (including reduced water levels) on the operation of emission control or other generation equipment, and the effects of a pandemic or terrorist attack on our workforce or facilities or on the ability of vendors and suppliers to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The operation of the New Units may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G’s territory or elsewhere in the region. Similarly, a gas transmission or distribution line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company’s revenues, results of operations, and financial condition. Insurance may not be available or adequate to respond to these events.

A failure of the Company to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's financial position, results of operations and cash flows.

The Company depends on maintaining the physical and cyber security of its operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our business could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's operations are dependent in some manner upon our cyber systems, which encompass electric and gas transmission and distribution operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, employee, or corporate information. The Company may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to respond to these events. As a result, the Company's financial position, results of operations, and cash flows may be adversely affected.

SCANA's ability to pay dividends and to make payments on SCANA's debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital .

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SEMI, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of Consolidated SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition. These risks will increase as the New Units are developed.

In 2013, Summer Station Unit 1, operated by SCE&G, provided approximately 5.6 million MWh, or 24% of our generation. When the New Units are completed, our generating capacity and the percentage of total generating capacity represented by nuclear sources are expected to increase. Hence, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident, if a major incident should occur at a domestic nuclear facility, it could harm our results of operations, cash flows and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Finally, in today's environment, there is a heightened risk of terrorist attack on the nation's nuclear facilities, which has resulted in increased security costs at our nuclear plant.

Failure to retain and attract key personnel could adversely affect the Company's and Consolidated SCE&G's operations and financial performance.

As with many other utilities, a significant portion of our workforce will be eligible for retirement during the next few years. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our business. Competition for these employees is high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. Further, the Company's or Consolidated SCE&G's ability to construct or maintain generation or other assets requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance.

***The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial position, and access to capital*.**

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously approved by regulators), to the detriment of the Company or Consolidated SCE&G. Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company's or Consolidated SCE&G's interests, may have a negative effect on our results of operations, cash flows and financial position, as well as limit our ability to access capital.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards of compliance with laws and regulations, ethical conduct, operational effectiveness, and safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company's and Consolidated SCE&G's access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to focus on the safety of employees, customers and the public, to maintain the privacy of information related to our customers and employees and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. The Company and Consolidated SCE&G also are committed to operational excellence and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments may subject the Company and Consolidated SCE&G not only to fraud, litigation and financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries.

SCE&G's bond indenture, securing the First Mortgage Bonds issued thereunder, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

ELECTRIC PROPERTIES

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2013.

	In-Service Date	Net Generating Capacity Summer (MW)	
Coal-Fired Steam:			
McMeekin - Near Irmo, SC	1958	250	*
Wateree - Eastover, SC	1970	684	
Williams - Goose Creek, SC	1973	605	
Cope - Cope, SC	1996	415	
Kapstone - Charleston, SC	1999	85	
Gas-Fired Steam - Urquhart Unit 3 - Beech Island, SC	1953	95	*
Nuclear - V. C. Summer - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647	
Internal Combustion Turbines:			
Peaking units - various locations in SC	1968-1999	352	

Urquhart Combined Cycle - Beech Island, SC	2002	458
Jasper Combined Cycle - Jasper, SC	2004	852
Hydro:		
Saluda - Irmo, SC	1930	200
Other hydro units - various locations in or bordering SC	1905-1914	18
Fairfield Pumped Storage - Parr, SC	1978	576

* As described in Note 2 to the consolidated financial statements for SCANA and SCE&G, under plans announced in 2012, SCE&G has retired or intends to retire six coal-fired units with an aggregate net generating capacity (summer rating) of 730 MW by 2018, subject to future developments in environmental regulations, among other matters. As of December 31, 2013, three of these units had been retired (with an aggregate net generating capacity, summer rating, of 385 MW) and are not included in the table above. Another unit, Urquhart Unit 3, was fueled with coal prior to 2013, and is expected to be fueled with natural gas until its retirement in 2018.

SCE&G owns 436 substations having an aggregate transformer capacity of 30 million KVA. The transmission system consists of 3,307 miles of lines, and the distribution system consists of 18,397 pole miles of overhead lines and 7,004 trench miles of underground lines.

NATURAL GAS DISTRIBUTION AND TRANSMISSION PROPERTIES

SCE&G's natural gas system includes 448 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and CGT. SCE&G’s distribution system consists of 16,450 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6 MMCF per day and store the liquefied equivalent of 980 MMCF of natural gas. The Salley facility can store the liquefied equivalent of 900 MMCF of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 60 MMCF per day at Charleston and 90 MMCF per day at Salley.

CGT’s natural gas system consists of 1,469 miles of transmission pipeline of up to 24 inches in diameter. CGT’s system transports gas to its customers from the transmission systems of Southern Natural at Port Wentworth, Georgia and Aiken County, South Carolina, Southern LNG, Inc. at Elba Island, near Savannah, Georgia and Transco in Cherokee and Spartanburg counties in South Carolina.

PSNC Energy’s natural gas system consists of 594 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy’s distribution system consists of 20,411 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000 MMCF, the capacity to liquefy up to 4 MMCF per day and the capacity to regasify approximately 100 MMCF per day. PSNC Energy also owns, through a wholly-owned subsidiary, 33.21% of Cardinal Pipeline Company, LLC, which owns a 105-mile transmission pipeline in North Carolina. In addition, PSNC Energy owns, through a wholly-owned subsidiary, 17% of Pine Needle LNG Company, LLC. Pine Needle owns and operates a liquefaction, storage and regasification facility in North Carolina.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G are engaged in various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on their respective results of operations, cash flows or financial condition. In addition, certain material regulatory and environmental matters and uncertainties, some of which remain outstanding at December 31, 2013, are described in the Rate Matters section of Note 2 and in the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

The executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	58	Chairman of the Board and Chief Executive Officer	2011-present
		President and Chief Operating Officer-SCANA	2011-present
		President and Chief Operating Officer-SCE&G	*-2011
Jimmy E. Addison	53	Executive Vice President	2012-present
		Chief Financial Officer	*-present
		Senior Vice President	*-2012
Jeffrey B. Archie	56	Senior Vice President and Chief Nuclear Officer-SCE&G	2009-present
		Senior Vice President-SCANA	2010-present
		Vice President of Nuclear Operations-SCE&G	*-2009
George J. Bullwinkel	65	President and Chief Operating Officer-SEMI, SCI and ServiceCare	*-present
		Senior Vice President-SCANA	*-present
Sarena D. Burch	56	Senior Vice President-Fuel Procurement and Asset Management-SCE&G and PSNC Energy	*-present
		Senior Vice President-SCANA	*-present
Stephen A. Byrne	54	President of Generation and Transmission and Chief Operating Officer-SCE&G	2011-present
		Executive Vice President-SCANA	2009-present
		Executive Vice President-Generation and Transmission -SCE&G	2011
		Executive Vice President-Generation, Nuclear and Fossil Hydro-SCE&G	2009-2011
		Senior Vice President-Generation, Nuclear and Fossil Hydro-SCE&G	*-2009
Paul V. Fant	60	President and Chief Operating Officer-CGT	*-present
		Senior Vice President-SCANA	*-present
D. Russell Harris	49	President of Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		Senior Vice President-Gas Distribution-SCANA	2013-present
		Senior Vice President-SCANA	2012-2013
W. Keller Kissam	47	President of Retail Operations-SCE&G	2011-present
		Senior Vice President-SCANA	2011-present
		Senior Vice President-Retail Electric-SCE&G	2011
		Vice President-Electric Operations-SCE&G	*-2011
Ronald T. Lindsay	63	Senior Vice President, General Counsel and Assistant Secretary	*-present
Charles B. McFadden	69	Senior Vice President-Governmental Affairs and Economic Development-SCANA Services	*-present
		Senior Vice President-SCANA	*-present
Martin K. Phalen	59	Senior Vice President-Administration-SCANA	2012-present
		Vice President-Gas Operations-SCE&G	*-2012

* Indicates position held at least since March 1, 2009.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

COMMON STOCK INFORMATION

SCANA Corporation:

Price Range (NYSE Composite Listing):

	2013				2012			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 48.15	$ 52.93	$ 54.41	$ 51.23	$ 49.64	$ 50.34	$ 48.24	$ 46.12
Low	$ 44.75	$ 45.72	$ 47.22	$ 45.57	$ 44.71	$ 47.18	$ 43.32	$ 43.56

SCANA common stock trades on the NYSE using the ticker symbol SCG. Newspaper stock listings use the name SCANA. At February 20, 2014 there were 141,144,841 shares of SCANA common stock outstanding which were held by approximately 28,121 shareholders of record. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2013, see Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

SCANA declared quarterly dividends on its common stock of $.5075 per share in 2013 and $.495 per share in 2012. On February 20, 2014, SCANA increased the quarterly cash dividend rate on SCANA common stock to $.525 per share, an increase of approximately 3.5%. The next quarterly dividend is payable April 1, 2014 to shareholders of record on March 10, 2014. For a discussion of provisions that could limit the payment of cash dividends, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCANA.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2013 and 2012, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount
February 15, 2012	$ 51.6 million	February 20, 2013	$ 62.2 million
May 3, 2012	52.3 million	April 25, 2013	62.0 million
August 2, 2012	54.0 million	July 31, 2013	65.8 million
October 24, 2012	44.3 million	October 31, 2013	60.0 million

On February 20, 2014, SCE&G declared dividends on its common stock of $62.5 million.

For a discussion of provisions that could limit the payment of cash dividends, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCE&G.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2013	2012	2011	2010	2009
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$ 4,495	$ 4,176	$ 4,409	$ 4,601	$ 4,237
Operating Income	$ 910	$ 859	$ 813	$ 768	$ 699
Preferred Stock Dividends	$ —	$ —	$ —	$ —	$ 9
Income Available to Common Shareholders	$ 471	$ 420	$ 387	$ 376	$ 348
Common Stock Data					
Weighted Average Common Shares Outstanding (Millions)	138.7	131.1	128.8	125.7	122.1
Basic Earnings Per Share	$ 3.40	$ 3.20	$ 3.01	$ 2.99	$ 2.85
Diluted Earnings Per Share	$ 3.39	$ 3.15	$ 2.97	$ 2.98	$ 2.85
Dividends Declared Per Share of Common Stock	$ 2.03	$ 1.98	$ 1.94	$ 1.90	$ 1.88
Balance Sheet Data					
Utility Plant, Net	$ 11,643	$ 10,896	$ 10,047	$ 9,662	$ 9,009
Total Assets	$ 15,164	$ 14,616	$ 13,534	$ 12,968	$ 12,094
Total Equity	$ 4,664	$ 4,154	$ 3,889	$ 3,702	$ 3,408
Short-term and Long-term Debt	$ 5,825	$ 5,744	$ 5,306	$ 4,909	$ 4,846
Other Statistics					
Electric:					
Customers (Year-End)	678,273	669,966	664,196	660,580	654,766
Total sales (Million kWh)	22,313	23,879	24,188	24,884	23,104
Generating capability-Net MW (Year-End)	5,237	5,533	5,642	5,645	5,611
Territorial peak demand-Net MW	4,574	4,761	4,885	4,735	4,557
Regulated Gas:					
Customers, excluding transportation (Year-End)	837,232	818,983	803,644	794,841	782,192
Sales, excluding transportation (Thousand Therms)	921,533	798,978	812,416	931,879	832,931
Transportation customers (Year-End)	496	499	492	491	482
Transportation volumes (Thousand Therms)	1,729,399	1,559,542	1,585,202	1,546,234	1,388,096
Retail Gas Marketing:					
Retail customers (Year-End)	454,104	449,144	455,258	464,123	455,198
Firm customer deliveries (Thousand Therms)	382,728	310,442	341,554	402,583	347,324
Nonregulated interruptible customer deliveries (Thousand Therms)	1,928,266	1,981,085	1,845,327	1,728,161	1,628,942
SCE&G:					
Statement of Income Data					
Operating Revenues	$ 2,845	$ 2,809	$ 2,819	$ 2,815	$ 2,569
Operating Income	$ 737	$ 717	$ 654	$ 604	$ 547
Net Income	$ 391	$ 352	$ 316	$ 304	$ 288
Net Income Attributable to Noncontrolling Interest	$ 11	$ 11	$ 10	$ 14	$ 7
Preferred Stock Dividends	$ —	$ —	$ —	$ —	$ 9
Earnings Available to Common Shareholder	$ 380	$ 341	$ 306	$ 290	$ 272
Balance Sheet Data					
Utility Plant, Net	$ 10,048	$ 9,375	$ 8,588	$ 8,198	$ 7,595
Total Assets	$ 12,700	$ 12,104	$ 11,037	$ 10,574	$ 9,813
Total Equity	$ 4,489	$ 4,043	$ 3,773	$ 3,541	$ 3,259
Short-term and Long-term Debt	$ 4,306	$ 4,171	$ 3,753	$ 3,440	$ 3,430
Other Statistics					
Electric:					
Customers (Year-End)	678,338	670,030	664,273	660,642	654,830
Total sales (Million kWh)	22,327	23,899	24,200	24,887	23,107
Generating capability-Net MW (Year-End)	5,237	5,533	5,642	5,645	5,611
Territorial peak demand-Net MW	4,574	4,761	4,885	4,735	4,557
Regulated Gas:					
Customers, excluding transportation (Year-End)	329,179	322,419	316,683	313,346	309,687
Sales, excluding transportation (Thousand Therms)	457,119	412,163	407,073	447,057	399,752

Transportation customers (Year-End)	173	166	155	148	130
Transportation volumes (Thousand Therms)	155,190	260,215	192,492	190,931	217,750

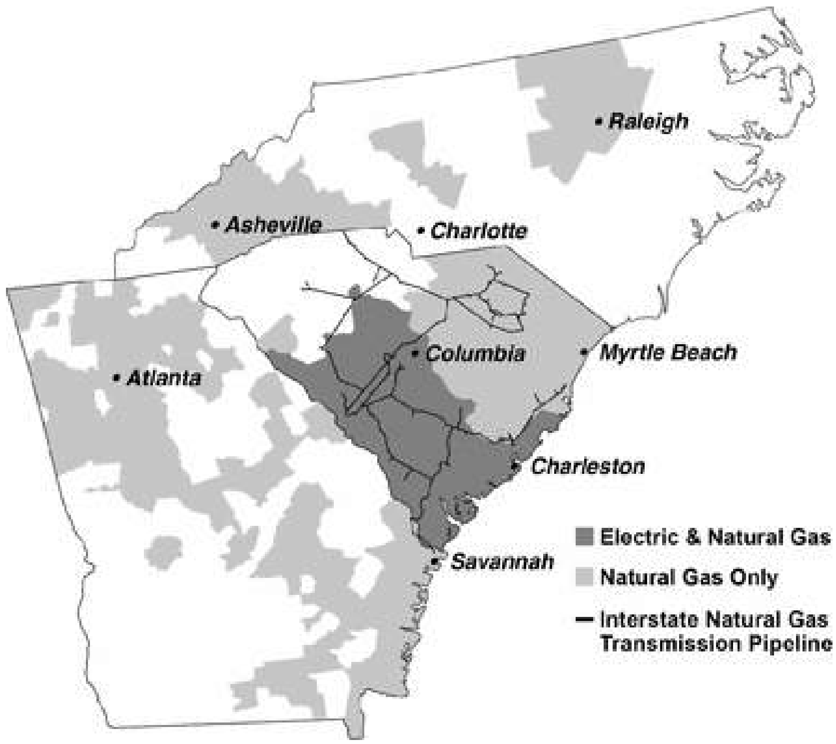
SCANA CORPORATION

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in parts of South Carolina and in the purchase, transmission and sale of natural gas in portions of North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers primarily in the southeast. Other wholly-owned nonregulated subsidiaries provide fiber optic and other telecommunications services and provide service contracts on certain home appliances and heating and air conditioning units. A service company subsidiary of SCANA provides administrative, management and other services to SCANA and its subsidiaries.

The following map indicates areas where the Company's significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect revenues and net income earned by the Company's regulated and nonregulated businesses (including the holding company) and the percentage of total assets held by them.

	2013	2012	2011
Revenues			
Regulated	75%	77%	74%
Nonregulated	25%	23%	26%
Net Income			
Regulated	97%	99%	97%
Nonregulated	3%	1%	3%
Assets			
Regulated	95%	95%	94%
Nonregulated	5%	5%	6%

Key Earnings Drivers and Outlook

During 2013, economic growth continued to improve in the southeast. Significant industrial announcements were made in the Company's South Carolina and North Carolina service territories during the year, and announcements made in previous years began to materialize. In addition, the Port of Charleston continues to see increased traffic, with container volume up 5.7% over 2012. Residential and commercial customer growth rates in the Company's regulated businesses also remained positive. Unemployment rates for the states in which the Company primarily provides service also improved in 2013, though such rates improved in part due to people leaving the workforce. Nationwide, the civilian labor force participation rate was 62.8% at December 31, 2013, matching a 35-year low.

Unemployment (seasonally adjusted)	United States	Georgia	North Carolina	South Carolina
December 31, 2013 (preliminary)	6.7%	7.4%	6.9%	6.6%
December 31, 2012	7.8%	8.7%	9.4%	8.6%
December 31, 2011	8.9%	9.4%	10.4%	9.6%

Over the next five years, key earnings drivers for the Company will be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business in Georgia and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

The electric operations segment is comprised of the electric operations of SCE&G, GENCO and Fuel Company, and is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina. At December 31, 2013, SCE&G provided electricity to approximately 678,000 customers in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results for electric operations are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control growth in costs. Through 2013, the effect of weather on operating results was largely mitigated by the eWNA; however, the eWNA was discontinued pursuant to SCPSC order effective with the first billing cycle of January 2014. Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2013 was 10.25% for non-BLRA expenditures, and 11.0% for BLRA-related expenditures. As further described in Note 2 to the consolidated financial statements, SCE&G's allowed return on equity for non-BLRA expenditures was 10.7% prior to 2013. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (2012 summer rating) of 730 MW. As of December 31, 2013, three of these units have been retired. For additional information, see Note 1 and Note 2 to the consolidated financial statements.

New Nuclear Construction

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

SCE&G expects Unit 2 to be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest.

Significant recent developments in new nuclear construction include the following:

- In the first quarter of 2013, initial pouring of the Unit 2 nuclear island basemat was completed. The basemat provides a foundation for the containment vessel, shield building and auxiliary building that make up the nuclear island. The Unit 3 nuclear island basemat was completed in the fourth quarter of 2013.

- In April 2013, the 500-ton CR-10 module was set on the Unit 2 basemat. CR-10 supports the containment vessel. Construction of Unit 3's CR-10 module is currently underway.

- In May 2013, the containment vessel bottom head for Unit 2 was put in place. The containment vessel will house numerous reactor system components, such as the reactor vessel, steam generator and pressurizer. Work continues in building containment vessel rings that will be placed on the containment vessel bottom head for Unit 2.

- In September 2013, the reactor vessel cavity for Unit 2 (CA-04 module) was placed in the containment vessel bottom head. The reactor vessel cavity will house the reactor vessel, which in turn will house the fuel assemblies. The reactor vessel for Unit 2 is on-site.

- Fabrication has begun for Unit 2's steam generator and refueling canal module (CA-01 module) that will be located inside the containment vessel.

- Ring 1 of the Unit 2 containment vessel is scheduled to be placed on the containment vessel bottom head in the second quarter 2014. Ring 2 is scheduled to be placed in the fourth quarter of 2014.

- While progress has been made with production, quality assurance and quality control issues, the schedule for fabrication of sub-modules at the contractor facility remains a focus area for the project.

- During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

For additional information on these and other matters, see New Nuclear Construction Matters herein and Note 2 and Note 10 to the consolidated financial statements.

Environmental

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. New federal effluent limitation guidelines for steam electric generating units were published in the Federal Register on

June 7, 2013, and the ELG Rule is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020. Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014, and Congress is expected to consider further amendments to the CWA.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 14, 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO.

The above environmental initiatives and other similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, the Company cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on the Company, if any. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The gas distribution segment, comprised of the local distribution operations of SCE&G and PSNC Energy, is primarily engaged in the purchase, transportation and sale of natural gas to retail customers in portions of South Carolina and North Carolina. At December 31, 2013 this segment provided natural gas to approximately 838,000 customers in areas covering 34,600 square miles.

Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control growth in costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25% for SCE&G and 10.60% for PSNC Energy.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company’s ability to retain large commercial and industrial customers. In addition, the production of shale gas in the United States has resulted in significantly lower prices for this commodity, and such prices are expected to continue for the foreseeable future.

Retail Gas Marketing

SCANA Energy, a division of SEMI, comprises the retail gas marketing segment. This segment markets natural gas to approximately 454,000 customers throughout Georgia (as of December 31, 2013, and includes approximately 68,000 customers in its regulated division described below). SCANA Energy’s total customer base represents an approximate 30% share of the customers in Georgia’s deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state. SCANA Energy’s competitors include an affiliate of a large energy company with experience in Georgia’s energy market, as well as several electric membership cooperatives. SCANA Energy’s ability to maintain its market share depends on the prices it charges customers relative to the prices charged by its competitors, its ability to continue to provide high levels of customer service and other factors. In addition, SCANA Energy's operating results are highly sensitive to weather. This market has matured in the last decade, resulting in lower margins and enhanced competition for customers.

As Georgia’s regulated provider, SCANA Energy provides service at rates approved by the GPSC to low-income customers and to customers unable to obtain or maintain natural gas service from other marketers . SCANA Energy receives funding from Georgia's Universal Service Fund to offset some of the bad debt associated with the low-income group. In third quarter 2013, SCANA Energy’s contract to serve as Georgia’s regulated provider of natural gas was extended by the GPSC through August 31, 2015. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed with the SEC).

SCANA Energy and certain of SCANA's other natural gas distribution and marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage their exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or otherwise placed under contract. Since SCANA Energy operates in a competitive market, it may be unable to sustain its current levels of customers and/or pricing, thereby reducing expected margins and profitability. Further, there can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as dynamic market conditions evolve.

Energy Marketing

The divisions of SEMI excluding SCANA Energy comprise the energy marketing segment. This segment markets natural gas primarily in the southeast and provides energy-related risk management services to customers. The operating results for energy marketing are primarily influenced by customer demand for natural gas and the ability to control growth of costs. Demand for natural gas is primarily affected by the price of alternate fuels and customer growth. In addition, certain pipeline capacity available for Energy Marketing to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the retail market.

RESULTS OF OPERATIONS

	2013	2012	2011
Basic earnings per share	$ 3.40	$ 3.20	$ 3.01
Diluted earnings per share	$ 3.39	$ 3.15	$ 2.97
Cash dividends declared (per share)	$ 2.03	$ 1.98	$ 1.94

2013 vs 2012 Basic earnings per share increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.

2012 vs 2011 Basic earnings per share increased due to higher electric and gas margins and gains on sales of communications towers. These increases were partially offset by higher operating expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.

Diluted earnings per share figures give effect to dilutive potential common stock using the treasury stock method. See Note 1 to the consolidated financial statements.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$ 2,430.5	(0.9)%	$ 2,453.1	0.9 %	$ 2,432.2
Less: Fuel used in generation	751.0	(11.0)%	844.2	(8.5)%	922.5
Purchased power	43.0	53.0 %	28.1	46.4 %	19.2
Margin	$ 1,636.5	3.5 %	$ 1,580.8	6.1 %	$ 1,490.5

2013 vs 2012	Margin increased primarily due to base rate increases under the BLRA of $54.2 million and higher electric base rates of $67.3 million approved in the December 2012 rate order. Additionally, pursuant to accounting orders of the SCPSC, 2013's electric margin reflects downward adjustments of $50.1 million to revenue. Such adjustments are fully offset by the recognition within other income of gains realized upon the settlement of certain derivative interest rate contracts, which had been deferred as regulatory liabilities. See Note 2 to the consolidated financial statements.
2012 vs 2011	Margin increased primarily by $54.4 million due to an increase in retail electric base rates approved by the SCPSC under the BLRA, by $3.7 million due to customer growth and by $11.0 million due to the expiration of a decrement rider approved in the 2010 retail electric base rate case.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2013	Change	2012	Change	2011
Residential	7,571	—	7,571	(8.0)%	8,232
Commercial	7,205	(1.2)%	7,291	(1.4)%	7,397
Industrial	6,000	2.8 %	5,836	(1.7)%	5,938
Other	581	(0.9)%	586	2.4 %	572
Total retail sales	21,357	0.3 %	21,284	(3.9)%	22,139
Wholesale	955	(63.2)%	2,595	26.6 %	2,049
Total Sales	22,312	(6.6)%	23,879	(1.3)%	24,188

2013 vs 2012	Retail sales volume increased primarily due to customer growth and the effects of weather, partially offset by lower average use. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.
2012 vs 2011	Retail sales volume decreased by 983 GWh primarily due to the effects of milder weather. The increase in wholesale sales is primarily due to higher contract utilization by a wholesale customer.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas Distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$ 942.6	23.2%	$ 765.0	(9.0)%	$ 840.4
Less: Gas purchased for resale	534.9	42.8%	374.6	(19.7)%	466.3
Margin	$ 407.7	4.4%	$ 390.4	4.4 %	$ 374.1

2013 vs 2012	Margin increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012, as well as residential and commercial customer growth and increased industrial usage.
2012 vs 2011	Margin at SCE&G increased by $8.3 million due to the SCPSC-approved increases in retail gas base rates under the RSA which became effective with the first billing cycles of November 2011 and 2012. Margin at PSNC Energy increased by $5.1 million primarily due to residential and commercial customer growth and increased industrial sales due to the competitive price of gas versus alternate fuel sources.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2013	Change	2012	Change	2011
Residential	41,268	24.4%	33,161	(9.3)%	36,568
Commercial	28,181	12.7%	25,001	(3.0)%	25,772
Industrial	22,319	4.6%	21,340	13.6 %	18,782
Transportation gas	42,221	9.0%	38,736	13.4 %	34,152
Total	133,989	13.3%	118,238	2.6 %	115,274

2013 vs 2012 Total sales volumes increased primarily due to customer growth, increased industrial usage and the effects of weather.

2012 vs 2011 Residential and commercial sales volume decreased primarily due to milder weather. Industrial and transportation sales volumes increased due to the competitive price of gas versus alternate fuel sources.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy which operates in Georgia's natural gas market. Retail Gas Marketing revenues and net income were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$ 465.2	12.8%	$ 412.5	(13.8)%	$ 478.8
Net Income	23.8	*	10.5	(56.6)%	24.2

* Greater than 100%

2013 vs 2012 Changes in operating revenues and net income are due to higher demand in 2013 primarily as a result of milder weather in 2012.

2012 vs 2011 Reductions in operating revenues and net income were primarily due to milder weather and a decrease in the number of customers served under the regulated provider program in 2012.

Energy Marketing

Energy Marketing is comprised of the Company's nonregulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net income were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$ 818.5	22.3%	$ 669.0	(20.8)%	$ 844.9
Net Income	6.1	13.0%	5.4	22.7 %	4.4

2013 vs 2012 Operating revenues and net income increased due to higher industrial sales volume and higher market prices.

2012 vs 2011 Operating revenues decreased due to lower market prices. Net income increased due to higher consumption.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Other operation and maintenance	$ 707.5	2.6%	$ 689.3	4.8%	$ 657.9
Depreciation and amortization	378.1	6.2%	356.1	2.8%	346.3
Other taxes	219.7	6.1%	207.1	3.1%	200.8

2013 vs 2012	Other operation and maintenance expenses increased by $16.7 million due to incremental expenses associated with the December 2012 SCPSC rate order and by $5.7 million due to higher electric generation, transmission and distribution expenses. These increases were partially offset by lower compensation costs of $10.1 million due to reduced headcount and lower incentive compensation accruals and by other general expenses. Depreciation and amortization expense increased $13.2 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 SCPSC rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes on net property additions.
2012 vs 2011	Other operation and maintenance expenses increased by $9.3 million due to higher generation, transmission and distribution expenses and by $25.0 million due to higher incentive compensation and other benefits. These increases were partially offset by $3.9 million due to lower customer service expenses, including bad debt expense, and by $1.6 million due to lower general expenses. Depreciation and amortization expense increased primarily due to net property additions. Other taxes increased primarily due to higher property taxes on net property additions.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on the Company's income statements and balance sheets as follows:

Millions of dollars	2013	Change	2012	Change	2011
Income Statement Impact:					
Employee benefit costs	$ 15.5	*	$ 4.0	53.8%	$ 2.6
Other expense	1.0	25.0 %	0.8	60.0%	0.5
Balance Sheet Impact:					
Increase in capital expenditures	7.2	9.1 %	6.6	69.2%	3.9
Component of amount receivable from Summer Station co-owner	2.5	13.6 %	2.2	83.3%	1.2
Increase in regulatory asset	5.5	(63.1)%	14.9	63.7%	9.1
Net periodic benefit cost	$ 31.7	11.2 %	$ 28.5	64.7%	$ 17.3

* Greater than 100%

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension cost related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension costs related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2 to the consolidated financial statements). In 2013, such amortizations totaled approximately $2.0 million for electric operations and $0.2 million for gas operations.

Other Income (Expense)

Other income (expense) includes the results of certain incidental activities of regulated subsidiaries and the activities of certain non-regulated subsidiaries. Components of other income (expense) were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Other income	$ 100.3	71.2%	$ 58.6	12.3%	$ 52.2
Other expense	(45.5)	8.1%	(42.1)	5.3%	(40.0)
Total	$ 54.8	*	$ 16.5	35.2%	$ 12.2

* Greater than 100%

2013 vs 2012	Changes in other income were primarily due to the recognition, pursuant to SCPSC accounting orders, of $50.1 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as regulatory liabilities. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income. This increase in other income was partially offset by the sales of communications towers that were recorded in 2012 by a non-regulated subsidiary. Changes in other expense were not significant.
2012 vs 2011	Changes in other income were primarily due to the sales of communications towers in 2012 by a non-regulated subsidiary. Changes in other expense were not significant.

AFC

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 5.8% of income before income taxes in 2013, 5.4% in 2012 and 3.9% in 2011.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Interest on long-term debt, net	$ 292.8	0.9 %	$ 290.2	4.9 %	$ 276.6
Other interest expense	4.6	(11.5)%	5.2	(32.5)%	7.7
Total	$ 297.4	0.7 %	$ 295.4	3.9 %	$ 284.3

Interest on long-term debt increased in each year primarily due to increased long-term borrowings. Other interest expense decreased in 2013 and 2012, primarily due to reductions in principal balances outstanding on short-term debt over the respective prior year and also decreased due to the reversal in 2012 of interest which had been accrued in 2011 related to a tax uncertainty that was resolved (see Note 5 to the consolidated financial statements).

Income Taxes

Income tax expense increased in 2013 over 2012 and in 2012 over 2011 primarily due to increases in income before taxes. The increase in the effective tax rate in 2013 is principally attributable to lower recognition of EIZ Credits upon the completion of the amortization of certain such credits in 2012.

LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its contractual cash obligations will be met through internally generated funds, the incurrence of additional short- and long-term indebtedness and sales of equity securities. The Company expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt. The Company's ratio of earnings to fixed charges for the year ended December 31, 2013 was 3.22.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of the regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

The Company obtains equity from SCANA's stock plans. Shares of SCANA common stock are acquired on behalf of participants in SCANA's Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares, rather than being purchased on the open market. This provided approximately $99 million of additional equity during 2013. Due primarily to new nuclear construction plans, the Company anticipates keeping this strategy in place for the foreseeable future.
In addition, on March 5, 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196 million.

SCANA's leverage ratio of long- and short-term debt to capital was approximately 56% at December 31, 2013. SCANA has publicly announced its desire to maintain its leverage ratio between 54% and 57%, but SCANA's ability to do so depends on a number of factors. In the future, if SCANA is not able to maintain its leverage ratio within the desired range, the Company's debt ratings may be affected, it may be required to pay higher interest rates on its long- and short-term indebtedness, and its access to the capital markets may be limited.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, net of AFC, were $1.1 billion in 2013 and are estimated to be $1.7 billion in 2014.

The Company's current estimates of its capital expenditures for construction and nuclear fuel for 2014-2016, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2014	2015	2016
SCE&G - Normal			
Generation	$ 136	$ 145	$ 112
Transmission & Distribution	230	280	258
Other	14	25	19
Gas	50	51	73
Common	9	7	10
Total SCE&G - Normal	439	508	472
PSNC Energy	128	111	87
Other	79	58	42
Total Normal	646	677	601
New Nuclear (including transmission)	950	905	667
Cash Requirements for Construction	1,596	1,582	1,268
Nuclear Fuel	67	30	147
Total Estimated Capital Expenditures	$ 1,663	$ 1,612	$ 1,415

Estimated capital expenditures for Nuclear Fuel in 2016 include approximately $53 million, which is SCE&G's share of nuclear fuel it acquired in 2013. This fuel has been recorded in utility plant and the corresponding liability has been recorded in long-term debt on the consolidated balance sheet.

The Company's contractual cash obligations as of December 31, 2013 are summarized as follows:

Contractual Cash Obligations

	Payments due by periods				
Millions of dollars	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long- and short-term debt, including interest	$ 10,954	$ 713	$ 885	$ 1,243	$ 8,113
Capital leases	17	3	10	2	2
Operating leases	41	7	12	3	19
Purchase obligations	3,938	2,067	1,648	221	2
Other commercial commitments	4,397	886	1,700	998	813
Total	$ 19,347	$ 3,676	$ 4,255	$ 2,467	$ 8,949

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at the Summer Station site. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent of the cost and receiving 55 percent of the output, and the other joint owner (or owners) the remaining 45 percent. Also included in the table above is the estimated $500 million SCE&G expects it will cost to acquire an additional 5% ownership in the New Units as further described in New Nuclear Construction Matters.

Also included in purchase obligations are customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Forward contracts for natural gas purchases include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $9.2 million in 2013, and such annual payments are expected to be the same or increase up to $14.7 million in the future.

In addition, the Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. See further discussion at Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. At December 31, 2013, the Company had posted $6.4 million in cash collateral for such contracts. In addition, the Company had posted $20.3 million in cash collateral related to interest rate derivative contracts.

The Company also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional asset retirement obligations that are not listed in the contractual cash obligations table. See Notes 1 and 10 to the consolidated financial statements.

Financing Limits and Related Matters

The Company's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC. Financing programs currently utilized by the Company follow.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million.

GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

In October 2013, the Company's existing committed LOCs were extended by one year. As a result, at December 31, 2013 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $300 million, $1.2 billion, of which $500 million relates to Fuel Company, and $100 million, respectively, which expire in October 2018. In addition, at December 31, 2013 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2013, the Company had no outstanding borrowings under its $1.8 billion credit facilities, had approximately $376 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC supported letters of credit, and held approximately $136 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2013 were approximately $463 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2013, the Company’s long-term debt portfolio has a weighted average maturity of approximately 18 years and bears an average cost of 5.74%. Substantially all of the Company's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, the Company rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCANA’s junior subordinated indenture (relating to the hereinafter defined Hybrids), SCE&G’s bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013, approximately $63.1 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

SCANA has outstanding $150 million of enhanced junior subordinated notes (Hybrids) which bear interest at 7.70% and mature on January 30, 2065, subject to extension to January 30, 2080. Because their structure and terms are characteristic of both debt instruments and equity securities, credit rating agencies consider securities like the Hybrids to be hybrid debt instruments and give some equity credit to the issuers of such securities for purposes of computing leverage ratios of debt to capital. The Hybrids are only subject to redemption at SCANA’s option and may be redeemed at any time, although the redemption prices payable by SCANA differ depending on the timing of the redemption and the circumstances (if any) giving rise thereto. SCANA may redeem the Hybrids on or after January 30, 2015, without payment of a make-whole amount.

In connection with the Hybrids, SCANA executed an RCC in favor of the holders of certain designated debt (referred to as “covered debt”). Under the terms of the RCC, SCANA agreed not to redeem or repurchase all or part of the Hybrids prior to the termination date of the RCC, unless it uses the proceeds of certain qualifying securities sold to non-affiliates within 180 days prior to the redemption or repurchase date. The proceeds SCANA receives from such qualifying securities, adjusted by a predetermined factor, must exceed the redemption or repurchase price of the Hybrids. Qualifying securities include common stock, and other securities that generally rank equal to or junior to the Hybrids and include distribution, deferral and long-dated maturity features similar to the Hybrids. For purposes of the RCC, non-affiliates include (but are not limited to) individuals enrolled in SCANA’s dividend reinvestment plan, direct stock purchase plan and employee benefit plans.

The RCC is scheduled to terminate on the earliest to occur of the following: (a) January 30, 2035 (or later, if the maturity date of the Hybrids is extended), (b) the date on which SCANA no longer has any eligible debt which ranks senior in right of payment to the Hybrids, (c) the date on which the holders of at least a majority in principal amount of “covered debt” agree to the termination thereof or (d) the date on which the Hybrids are accelerated following an event of default with respect thereto. SCANA's $250 million in Medium Term Notes due April 1, 2020 are designated as "covered debt" under the RCC.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Financing Activities

During 2013 there were net cash outflows related to financing activities of approximately $40 million primarily due to repayment of short- and long-term debt and payment of dividends, partially offset by the issuance of common stock and long-term debt.

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

On March 5, 2013, SCANA settled all forward sales contracts related to 6.6 million shares of its common stock, resulting in net proceeds of approximately $196 million.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.625% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027.

In November 2012, SCE&G repaid at maturity $4.4 million of 4.2% tax-exempt industrial revenue bonds, and repaid prior to maturity $29.2 million of 5.45% tax-exempt industrial revenue bonds due November 1, 2032.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042 (issued at a premium with a yield of 3.86%), which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds which were issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

In January 2012, SCANA issued $250 million of 4.125% medium term notes due February 1, 2022. Proceeds from the sale were used by SCANA to retire $250 million of its 6.25% medium term notes due February 1, 2012.

Investing Activities

The Company paid approximately $6 million, net, through the third quarter of 2013 to settle interest rate derivative contracts upon the issuance of long-term debt for contracts that had been designated as hedges.

In addition, during the fourth quarter of 2013, the Company received approximately $120 million upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt. Pursuant to SCPSC accounting orders, $50.1 million of such gains were recognized within other income, with such gain recognition being fully offset by downward adjustments to revenues reflected within electric margin.

For additional information, see Note 4 to the consolidated financial statements.

In February 2014, SCANA increased the quarterly cash dividend rate on SCANA common stock to $.525 per share, an increase of approximately 3.5% from the prior declared dividend. The next quarterly dividend is payable April 1, 2014 to shareholders of record on March 10, 2014.

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act included 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 and 50% bonus depreciation for property placed in service for 2012. The American Taxpayer Relief Act of 2012 extended the 50% bonus depreciation for property placed in service in 2013. These incentives, along with certain other deductions, have had a positive impact on the cash flows of the Company.

ENVIRONMENTAL MATTERS

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. Compliance with these environmental requirements involves significant capital and operating costs, which the Company expects to recover through existing ratemaking provisions.

For the three years ended December 31, 2013, the Company's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $46.1 million. In addition, the Company made expenditures to operate and maintain environmental control equipment at its fossil plants of $9.2 million in 2013, $10.2 million in 2012 and $7.9 million during 2011, which are included in “Other operation and maintenance” expense, and made expenditures to handle waste ash of $3.2 million in 2013, $7.9 million in 2012 and $8.7 million in 2011, which are included in “Fuel used in electric generation.” In addition, included within “Other operation and maintenance” expense is an annual amortization of $1.4 million in each of 2013, 2012 and 2011 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $9.5 million for 2014 and $82.5 million for the four-year period 2015-2018. These expenditures are included in the Company's Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

At the state level, no significant environmental legislation that would affect the Company's operations advanced during 2013. The Company cannot predict whether such legislation will be introduced or enacted in 2014, or if new regulations or changes to existing regulations at the state level will be implemented in the coming year. Several regulatory initiatives at the federal level did advance in 2013 and more are expected to advance in 2014 as described below.

Air Quality

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. The Company also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on the Company, if any. The Company expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed the Company to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. The Company will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in the Company's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

Physical effects associated with climate changes could include the impact of possible changes in weather patterns, such as storm frequency and intensity, and the resultant potential damage to the Company's electric system, as well as impacts on employees and customers and on the Company's supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. In addition, SCE&G has collected funds from customers for its storm damage reserve (see Note 2 to the consolidated financial statements). As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations in advance of such storms, all in order to allow the Company to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Water Quality

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014, The Company is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of the Company. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

Hazardous and Solid Wastes

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While the Company cannot predict how extensive the regulations will be, the Company believes that any additional costs imposed by such regulations would be recoverable through rates.

The final CCR rule may require the closure of ash ponds. SCE&G has three generating facilities that have employed ash storage ponds, and all of these ponds have either been closed after all ash was removed or are part of an ash pond closure project that includes complete removal of the ash prior to closure. The electric generating facilities which continue to be coal-fired have dry ash handling, and the ash ponds undergoing closure have a detailed dam safety inspection conducted at least quarterly.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2013, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017, and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates. The Company has assessed the following matters:

Electric Operations

SCE&G maintains an environmental assessment program to identify and evaluate its current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. At December 31, 2013, such regulatory assets totaled approximately $1.2 million. Other environmental costs are recorded to expense as incurred.

Gas Distribution

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC. SCE&G anticipates that major remediation activities at these sites will continue until 2017 and will cost an additional $20.2 million. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

PSNC Energy is responsible for environmental clean-up at five sites in North Carolina on which MGP residuals are present or suspected. PSNC Energy's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $2.8 million, the estimated remaining liability at December 31, 2013. PSNC Energy expects to recover through rates any cost allocable to PSNC Energy arising from the remediation of these sites.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC to the extent they transact swaps as defined in Dodd-Frank.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions and other matters; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety, antitrust considerations and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale for resale, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to issuance of short-term borrowings, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.
SCE&G, PSNC Energy and CGT	The PHMSA and the DOT as to integrity management requirements for gas distribution pipeline systems and natural gas transmission systems, respectively.
CGT	The FERC as to transportation rates, service, accounting and other matters.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the Company's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Utility Regulation

SCANA's regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of the Company's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the Company's regulatory assets and liabilities, including those associated with the Company's environmental program.

The Company's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, the Company could be required to write down its investment in those assets. The Company cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect the Company's results of operations in the period in which they would be recorded. As of December 31, 2013, the Company's net investments in fossil/hydro and nuclear generation assets were approximately $2.4 billion and $2.9 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the Company's utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, the Company records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. Accounts receivable included unbilled revenues of $183.1 million at December 31, 2013 and $189.8 million at December 31, 2012, compared to total revenues of $4.5 billion and $4.2 billion for the years 2013 and 2012, respectively.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact the Company's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

Asset Retirement Obligations

The Company accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation in accordance with applicable accounting guidance. The obligations are recognized at present value in the period in which they are incurred, and associated asset retirement costs are capitalized as a part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to the Company's regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2013, the Company has recorded AROs of $191 million for nuclear plant decommissioning (as discussed above) and AROs of $385 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded in accordance with the relevant accounting guidance are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. The Company's plan is adequately funded under current regulations. Accounting guidance requires the use of several assumptions, the selection of which has an impact on the resulting pension cost recorded. Among the more sensitive assumptions are those surrounding discount rates and expected returns on assets. Net pension cost of $31.7 million recorded in 2013 reflects the use of a 4.10% discount rate prior to re-measurement on September 1, 2013 and a 5.07% discount rate after re-measurement, derived using a cash flow matching technique, and an assumed 8.0% long-term rate of return on plan assets. The re-measurement occurred in connection with a plan amendment and related curtailment, which is further described below. The Company believes that these assumptions were, and that the resulting pension cost amount was, reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2013 would have increased the Company's pension cost by $1.2 million. Further, had the assumed long-term rate of return on assets been 7.75%, the Company's pension cost for 2013 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

The Company determines the fair value of a large majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2013, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 7.5%, 6.3%, 8.8% and 9.7%, respectively. The 2013 expected long-term rate of return of 8.00% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2014, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.4%, 6.0%, 8.3% and 9.3%, respectively. For 2014, the expected rate of return is 8.00%.

As of December 31, 2013, 2012, and 2011, approximately $5.5 million, $14.9 million and $9.0 million, respectively, of pension expense was deferred pursuant to regulatory orders. As part of a December 2012 SCPSC rate order, cumulative previously deferred pension costs related to electric operations of approximately $63 million is being amortized over approximately 30 years, and starting in January 2013 current pension expense for electric operations is being recovered through a pension cost rider. Similarly, in connection with the October 2013 RSA order, previously deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates.

In the third quarter of 2013, the pension plan was amended such that pension benefits will no longer be offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the Company recorded a curtailment charge due to the accelerated amortization of prior service cost. Approximately $6.5 million of the curtailment charge was applicable to regulated operations and was deferred within regulatory assets. The Company is recovering such deferred amounts through existing regulatory orders.

The closure of the plan to entrants after December 31, 2013 and the cessation of benefit accruals in 2023 are expected to further lessen the significance of pension costs and the criticality of the related estimates to the Company's financial statements. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

The Company accounts for the cost of its postretirement medical and life insurance benefit plans in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.19%, derived using a cash flow matching technique, and recorded a net cost of $21.3 million for 2013. Had the selected discount rate been 3.94% (25 basis points lower than the discount rate referenced above), the expense for 2013 would have been $0.6 million higher. Because the plan provisions include "caps" on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

NEW NUCLEAR CONSTRUCTION MATTERS

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

It is expected that Unit 2 will be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in revised rates filings under the BLRA.

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution of these specific claims is discussed in Note 2 to the consolidated financial statements. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide for detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units’ reactor buildings (March 2013 for the first New Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification. Under current provisions of the Internal Revenue Code and based on SCE&G's current 55% ownership and other assumptions regarding volumes of electricity to be generated by the New Units, the aggregate production tax credits for which SCE&G qualifies could exceed $1.3 billion over the eight year period following each of the New Units' in-service dates. In January 2014, SCE&G amended its application to include the additional 5% interest in the New Units that it expects to acquire. Additional production tax credits related to the 5% interest could total as much as $125 million.

OTHER MATTERS

Financial Regulatory Reform

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

Off-Balance Sheet Transactions

Although SCANA invests in securities and business ventures, it does not hold significant investments in unconsolidated special purpose entities. SCANA does not engage in off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by the Company described below are held for purposes other than trading.

Interest Rate Risk

The tables below provides information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2013	**Expected Maturity Date**							
Millions of dollars	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	46.7	10.8	109.6	8.7	717.9	4,386.5	5,280.2	5,753.3
Average Fixed Interest Rate (%)	4.83	4.72	1.14	4.84	5.95	5.43	5.40	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	138.2	160.2	154.4
Average Variable Interest Rate (%)	0.94	0.94	0.94	0.94	0.94	0.53	0.59	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	604.4	654.4	4.4	4.4	4.4	141.8	1,413.8	13.0
Average Pay Interest Rate (%)	3.97	4.17	6.17	6.17	6.17	4.72	4.16	—
Average Receive Interest Rate (%)	0.25	0.25	0.94	0.94	0.94	0.49	0.28	—

December 31, 2012	**Expected Maturity Date**							
Millions of dollars	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	162.0	46.1	9.8	8.6	7.7	4,706.0	4,940.2	5,941.4
Average Fixed Interest Rate (%)	6.96	4.86	4.92	5.03	5.12	5.59	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	142.6	164.6	157.5
Average Variable Interest Rate (%)	1.01	1.01	1.01	1.01	1.01	0.61	0.66	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	604.4	304.4	4.4	4.4	4.4	146.2	1,068.2	(33.6)
Average Pay Interest Rate (%)	3.04	2.53	6.17	6.17	6.17	4.76	3.17	—
Average Receive Interest Rate (%)	0.31	0.32	1.01	1.01	1.01	0.58	0.36	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above tables exclude long-term debt of $3 million at December 31, 2013 and $9 million at December 31, 2012, which amounts do not have a stated interest rate associated with them.

For further discussion of the Company's long-term debt and interest rate derivatives, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

Commodity Price Risk

The following tables provide information about the Company's financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity:

Futures Contracts		
2014	**Long**	**Short**
Settlement Price (a)	4.18	4.17
Contract Amount (b)	13.0	0.7
Fair Value (b)	14.0	0.7
2015		
Settlement Price (a)	4.27	4.1
Contract Amount (b)	1.1	0.2
Fair Value (b)	1.2	0.2

Options		
2014	**Purchased Call (Long)**	**Purchased Put (Short)**
Strike Price (a)	4.01	4.10
Contract Amount (b)	26.6	0.2
Fair Value (b)	2.2	—
2015		
Strike Price (a)	4.30	—
Contract Amount (b)	0.1	—
Fair Value (b)	—	—

(a) Weighted average, in dollars

(b) Millions of dollars

Swaps	**2014**	**2015**	**2016**	**2017**
Commodity Swaps:				
Pay fixed/receive variable (b)	51.9	17.1	10.0	1.0
Average pay rate (a)	4.2063	4.9039	4.7098	4.1275
Average received rate (a)	4.1774	4.1634	4.1284	4.1530
Fair Value (b)	51.6	14.5	8.8	1.1
Pay variable/receive fixed (b)	32.4	14.0	8.7	1.1
Average pay rate (a)	4.1720	4.1621	4.1296	4.1530
Average received rate (a)	4.2845	4.9363	4.7143	4.1325
Fair Value (b)	33.3	16.6	9.9	1.1
Basis Swaps:				
Pay variable/receive variable (b)	1.0	0.5	—	—
Average pay rate (a)	4.2256	4.3982	—	—
Average received rate (a)	4.1700	4.3767	—	—
Fair Value (b)	1.0	0.5	—	—

(a) Weighted average, in dollars

(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements. The information above includes those financial positions of Energy Marketing and PSNC Energy.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

SCANA Corporation
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2013	2012
Assets		
Utility Plant In Service	$ 12,213	$ 11,865
Accumulated Depreciation and Amortization	(4,011)	(3,811)
Construction Work in Progress	2,724	2,084
Plant to be Retired, Net	177	362
Nuclear Fuel, Net of Accumulated Amortization	310	166
Goodwill	230	230
Utility Plant, Net	11,643	10,896
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $150 and $139	317	306
Assets held in trust, net-nuclear decommissioning	101	94
Other investments	86	87
Nonutility Property and Investments, Net	504	487
Current Assets:		
Cash and cash equivalents	136	72
Receivables, net of allowance for uncollectible accounts of $6 and $7	802	780
Inventories:		
Fuel	231	304
Materials and supplies	131	136
Emission allowances	1	1
Prepayments and other	120	223
Deferred income taxes	—	11
Total Current Assets	1,421	1,527
Deferred Debits and Other Assets:		
Regulatory assets	1,360	1,464
Pension asset	47	—
Other	189	242
Total Deferred Debits and Other Assets	1,596	1,706
Total	$ 15,164	$ 14,616

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2013	2012
Capitalization and Liabilities		
Common equity	$ 4,664	$ 4,154
Long-Term Debt, Net	5,395	4,949
Total Capitalization	10,059	9,103
Current Liabilities:		
Short-term borrowings	376	623
Current portion of long-term debt	54	172
Accounts payable	425	428
Customer deposits and customer prepayments	88	86
Taxes accrued	206	164
Interest accrued	82	82
Dividends declared	69	66
Derivative financial instruments	8	80
Other	134	110
Total Current Liabilities	1,442	1,811
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,703	1,653
Deferred investment tax credits	32	36
Asset retirement obligations	576	561
Postretirement benefits	227	387
Regulatory liabilities	966	882
Other	159	183
Total Deferred Credits and Other Liabilities	3,663	3,702
Commitments and Contingencies (Note 10)	—	—
Total	$ 15,164	$ 14,616

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31, (Millions of dollars, except per share amounts)	2013	2012	2011
Operating Revenues:			
Electric	$ 2,423	$ 2,446	$ 2,424
Gas-regulated	955	774	849
Gas-nonregulated	1,117	956	1,136
Total Operating Revenues	4,495	4,176	4,409
Operating Expenses:			
Fuel used in electric generation	745	838	917
Purchased power	43	28	19
Gas purchased for resale	1,491	1,198	1,455
Other operation and maintenance	708	690	658
Depreciation and amortization	378	356	346
Other taxes	220	207	201
Total Operating Expenses	3,585	3,317	3,596
Operating Income	910	859	813
Other Income (Expense):			
Other income	100	59	52
Other expenses	(46)	(42)	(40)
Interest charges, net of allowance for borrowed funds used during construction of $14, $11 and $7	(297)	(295)	(284)
Allowance for equity funds used during construction	27	21	14
Total Other Expense	(216)	(257)	(258)
Income Before Income Tax Expense	694	602	555
Income Tax Expense	223	182	168
Net Income	$ 471	$ 420	$ 387
Per Common Share Data			
Basic Earnings Per Share of Common Stock	$ 3.40	$ 3.20	$ 3.01
Diluted Earnings Per Share of Common Stock	3.39	3.15	2.97
Weighted Average Common Shares Outstanding (millions)			
Basic	138.7	131.1	128.8
Diluted	139.1	133.3	130.2

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (Millions of dollars)	2013	2012	2011
Net Income	$ 471	$ 420	$ 387
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $4, $(5) and $(36)	7	(8)	(58)
Losses on cash flow hedging activities reclassified to net income, net of tax of $7, $12 and $8	11	19	13
Net unrealized gains (losses) on cash flow hedging activities	18	11	(45)
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $4, $(2) and $(2)	7	(4)	(3)
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax of $-, $- and $-	1	1	1
Net deferred costs of employee benefit plans	8	(3)	(2)
Other Comprehensive Income (Loss)	26	8	(47)
Total Comprehensive Income	$ 497	$ 428	$ 340

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2013	2012	2011
Cash Flows From Operating Activities:			
Net Income	$ 471	$ 420	$ 387
Adjustments to reconcile net income to net cash provided from operating activities:			
Earnings from equity method investments, net of distributions	7	—	2
Deferred income taxes, net	49	130	164
Depreciation and amortization	393	368	354
Amortization of nuclear fuel	57	44	40
Allowance for equity funds used during construction	(27)	(21)	(14)
Carrying cost recovery	(3)	—	—
Changes in certain assets and liabilities:			
Receivables	(38)	5	34
Inventories	21	(53)	(44)
Prepayments and other	(12)	3	58
Regulatory assets	113	(172)	(173)
Regulatory liabilities	56	62	(17)
Accounts payable	24	34	(99)
Taxes accrued	42	10	8
Interest accrued	—	8	2
Pension and other postretirement benefits	(217)	89	90
Other assets	78	(120)	34
Other liabilities	36	32	(15)
Net Cash Provided From Operating Activities	1,050	839	811
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,106)	(1,077)	(884)
Proceeds from investments (including derivative collateral posted)	222	472	36
Purchase of investments (including derivative collateral posted)	(176)	(414)	(168)
Payments upon interest rate derivative contract settlement	(49)	(51)	(61)
Proceeds from interest rate derivative contract settlement	163	14	—
Net Cash Used For Investing Activities	(946)	(1,056)	(1,077)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	295	97	97
Proceeds from issuance of long-term debt	451	759	826
Repayments of long-term debt	(258)	(309)	(668)
Dividends	(281)	(257)	(248)
Short-term borrowings, net	(247)	(30)	233
Net Cash Provided From (Used For) Financing Activities	(40)	260	240
Net Increase (Decrease) in Cash and Cash Equivalents	64	43	(26)
Cash and Cash Equivalents, January 1	72	29	55
Cash and Cash Equivalents, December 31	$ 136	$ 72	$ 29
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $14, $11 and $7)	$ 288	$ 281	$ 276
—Income taxes	104	107	6
Noncash Investing and Financing Activities:			
Accrued construction expenditures	111	124	85
Capital leases	6	8	6
Nuclear fuel purchase	98	—	—

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON EQUITY

Millions	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance as of January 1, 2011	127	$ 1,789	$ 1,960	$ (47)	$ 3,702
Net Income			387		387
Other Comprehensive Loss, net of taxes of $(29)				(47)	(47)
Total Comprehensive Income (Loss)			387	(47)	340
Issuance of Common Stock	3	97			97
Dividends Declared			(250)		(250)
Balance as of December 31, 2011	130	1,886	2,097	(94)	3,889
Net Income			420		420
Other Comprehensive Income, net of taxes of $5				8	8
Total Comprehensive Income			420	8	428
Issuance of Common Stock	2	97			97
Dividends Declared			(260)		(260)
Balance as of December 31, 2012	132	1,983	2,257	(86)	4,154
Net Income			471		471
Other Comprehensive Income, net of taxes of $16				26	26
Total Comprehensive Income			471	26	497
Issuance of Common Stock	9	297			297
Dividends Declared			(284)		(284)
Balance as of December 31, 2013	141	$ 2,280	$ 2,444	$ (60)	$ 4,664

Dividends declared per share of common stock were $2.03, $1.98 and $1.94 for 2013, 2012 and 2011, respectively.

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia. The Company also conducts other energy-related business and provides fiber optic communications in South Carolina.

The accompanying consolidated financial statements reflect the accounts of SCANA and the following wholly-owned subsidiaries.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	SCANA Communications, Inc.
South Carolina Generating Company, Inc.	ServiceCare, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Services, Inc.
Carolina Gas Transmission Corporation	SCANA Corporate Security Services, Inc.

The Company reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated substantially at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company's regulated subsidiaries calculated AFC using average composite rates of 6.9% for 2013, 6.3% for 2012 and 4.7% for 2011. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

The Company records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were as follows:

	2013	2012	2011
SCE&G	2.96%	2.93%	2.92%
GENCO	2.66%	2.66%	2.69%
CGT	2.19%	2.09%	2.00%
PSNC Energy	3.01%	3.01%	3.05%
Aggregate of Above	2.93%	2.90%	2.90%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2013		2012	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.1 billion	—	$ 1.1 billion	—
Accumulated depreciation	$566.9 million	—	$557.0 million	—
Construction work in progress	$127.1 million	$2.3 billion	$113.6 million	$1.8 billion

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC. For a discussion of when the New Units are expected to be placed in service, and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $75.6 million at December 31, 2013 and $92.9 million at December 31, 2012.

Plant to be Retired

As previously disclosed, in 2012 SCE&G identified a total of six coal-fired units that it intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (summer 2012) of 730 MW. As of December 31, 2013, three of these units had been retired and their net carrying value is recorded in regulatory assets (see Note 2). The net carrying value of the remaining units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these remaining units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the consolidated balance sheet (see Note 2). Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2013 and 2012, SCE&G incurred $18.1 million and $11.1 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. SCE&G accrued $1.2 million per month from January 2010 through December 2012 for its portion of the outages in the spring of 2011 and the fall of 2012. Total costs for the 2011 outage were $34.1 million, of which SCE&G was responsible for $22.7 million. Total costs for the 2012 outage were $32.3 million, of which SCE&G was responsible for $21.5 million. In connection with the SCPSC's December 2012 approval of SCE&G's retail electric rates (see Note 2), effective January 1, 2013, SCE&G began to accrue $1.4 million per month for its portion of the nuclear refueling outages that are scheduled to occur through the spring of 2020.

Goodwill

The Company considers amounts categorized by FERC as “acquisition adjustments” with carrying values of $210 million (net of writedown of $230 million) for PSNC Energy (Gas Distribution segment) and $20 million for CGT (All Other segment) to be goodwill. The Company tests these goodwill amounts for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. The goodwill impairment testing is generally a two-step quantitative process which in step one requires estimation of the fair value of the respective reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. In the first quarter of 2012, the Company adopted guidance under which it has the option to first perform a qualitative assessment of impairment. Based on this qualitative ("step zero") assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with the two-step quantitative assessment.

In evaluations of PSNC Energy, fair value was estimated using the assistance of an independent appraisal. In evaluations of CGT, prior to the adoption of the new guidance, estimated fair value was obtained from discounted cash flow and other analysis. Step zero was utilized for CGT’s evaluation as of January 1, 2013, and step one (via discounted cash flow and other analysis) was again utilized for the evaluation as of January 1, 2014. In all evaluations for the periods presented, step one or step zero, as applicable, has indicated no impairment. The estimated fair values of the reporting units are substantially in excess of their carrying values, and no impairment charges have been recorded; however, should a write-down be required in the future, such a charge would be treated as an operating expense.

Nuclear Decommissioning

SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars, pursuant to an updated decommissioning cost study performed in 2012. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2013, 2012 and 2011) are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Accounts Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Inventory

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas and fuel oil. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable. Emission allowances are included in inventory at average cost. Emission allowances are expensed at weighted average cost as used and recovered through fuel cost recovery rates approved by the SCPSC.

Asset Management and Supply Service Agreements

PSNC Energy utilizes asset management and supply service agreements with counterparties for certain natural gas storage facilities. Such counterparties held 48% and 44% of PSNC Energy's natural gas inventory at December 31, 2013 and December 31, 2012, respectively, with a carrying value of $22.8 million and $19.6 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees. No fees are received under supply service agreements. The agreements expire March 31, 2015.

Income Taxes

The Company files a consolidated federal income tax return. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or revenues would be recognized by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

The Company records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are recorded to expense as incurred.

Income Statement Presentation

In its consolidated statements of income, the Company presents the revenues and expenses of its regulated businesses and its retail natural gas marketing businesses (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

The Company records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $183.1 million at December 31, 2013 and $189.8 million at December 31, 2012.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy's PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented an eWNA on a pilot basis for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC. See Note 2.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

The Company computes basic earnings per share by dividing net income by the weighted average number of common shares outstanding for the period. The Company computes diluted earnings per share using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method. The Company has issued no securities that would have an antidilutive effect on earnings per share.

A reconciliation of the weighted average number of common shares for each of the three years ended December 31, for basic and diluted purposes is as follows:

In Millions	2013	2012	2011
Weighted Average Shares Outstanding—Basic	138.7	131.1	128.8
Net effect of equity forward contracts	0.4	2.2	1.4
Weighted Average Shares Outstanding—Diluted	139.1	133.3	130.2

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G. In April 2012, the SCPSC approved SCE&G's request to decrease the total fuel cost component of its retail electric rates, and approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to recover an amount equal to its actual under-collected balance of base fuel and variable environmental costs as of April 30, 2012, or $80.6 million, over a twelve month period beginning with the first billing cycle of May 2012.

This April 2012 order was superseded, in part, by a December 2012 rate order in which the SCPSC authorized SCE&G to reduce the base fuel cost component of its retail electric rates and, in doing so, stated that SCE&G may not adjust its base fuel cost component prior to the last billing cycle of April 2014 except where necessary due to extraordinary unforeseen economic or financial conditions. In February 2013, in connection with its annual review of base rates for fuel costs, SCE&G requested authorization to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. Consistent with the December 2012 rate order, SCE&G did not request any adjustment to its base fuel cost component. In March 2013, SCE&G, ORS and the SCEUC entered into a settlement agreement accepting the proposed lower environmental fuel cost component effective with the first billing cycle of May 2013, and providing for the accrual of certain debt-related carrying costs on a portion of the under-collected balance of fuel costs. The SCPSC issued an order dated April 30, 2013, adopting and approving the settlement agreement and approving SCE&G's total fuel cost component. A public hearing for the annual review of base rates for fuel costs has been scheduled for April 3, 2014.

Pursuant to a November 2013 SCPSC accounting order, the Company's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term borrowing rate, and during 2013, $2.9 million of such carrying costs were accrued within other income. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates (as discussed above), a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. In February 2013, the SCPSC denied the SCEUC's petition for rehearing and the denial was not appealed.

The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills and had been in use since August 2010. In connection with the December 2012 order, SCE&G agreed to perform a study of alternative structures for eWNA. On November 1, 2013, the ORS filed a report with the SCPSC recommending that the eWNA be terminated with the last billing cycle for December 2013. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition.

In connection with the above termination of the eWNA program effective December 31, 2013, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. Pursuant to the SCPSC accounting order granting the above relief and terminating the eWNA, such revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. One of these units was retired in 2012, and two others were retired in the fourth quarter of 2013. The net carrying value of these retired units is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

In a July 2010 order, the SCPSC provided for a $48.7 million credit to SCE&G's customers over two years to be offset by accelerated recognition of previously deferred state income tax credits. These tax credits were fully amortized in 2012.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and lost net margin revenue associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC has approved the following rate changes pursuant to annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million
2011	First billing cycle of June	$7.0 million

Other activity related to SCE&G's DSM Programs is as follows:

- In May 2013 the SCPSC ordered the deferral of one-half of the net lost revenues and provided for their recovery over a 12-month period beginning with the first billing cycle in May 2014.

- In November 2013 the SCPSC approved SCE&G's continued use of DSM programs for another six years, including approval of the rate rider mechanism and a revised portfolio of DSM programs.

- In January 2014 SCE&G submitted its annual DSM Programs filing to the SCPSC, which included, among other things, a request to (1) recover one-half of the balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2014 and to recover the remaining balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2015, (2) utilize approximately $17.8 million of the gains from the recent settlement of certain interest rate derivative instruments to offset a portion of the net lost revenues component of SCE&G's DSM Programs rider, and (3) apply $ 5 million of its storm damage reserve and a portion of the gains from the recent settlement of certain interest rate derivative instruments, currently estimated to be $5.5 million, to the remaining balance of deferred net lost revenue as of April 30, 2014, deferred within regulatory assets resulting from the May 2013 order previously described.

Electric - BLRA

In May 2011, the SCPSC approved an updated capital cost schedule sought by SCE&G that, among other matters, incorporated then-identifiable additional capital costs of $173.9 million (SCE&G's portion in 2007 dollars).

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals. For further discussion of new nuclear construction matters, see Note 9.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved the following rate changes under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2013	2.90%	$ 67.2 million
2012	2.30%	$ 52.1 million
2011	2.40%	$ 52.8 million

Gas

SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2013	No change	
2012	2.10% Increase	$ 7.5 million
2011	2.10% Increase	$ 8.6 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2013 and 2012 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each review period were reasonable and prudent.

PSNC Energy

PSNC Energy is subject to a Rider D rate mechanism which allows it to recover from customers all prudently incurred gas costs and certain uncollectible expenses related to gas cost. The Rider D rate mechanism also allows PSNC Energy to recover, in any manner authorized by the NCUC, losses on negotiated gas and transportation sales.

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

In October 2013, in connection with PSNC Energy's 2013 Annual Prudence Review, the NCUC issued an order finding that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2013.

During the third quarter of 2013, the State of North Carolina passed legislation that makes changes to statutes covering gross receipts, sales and use, excise, franchise and income taxes. In the fourth quarter, in response to this legislation, the

NCUC initiated a proceeding to investigate how it should proceed in response to the enactment of such legislation. Because the investigation was not completed before January 1, 2014, the NCUC issued an order notifying utilities that the incremental revenue requirement impact associated with the change in the level of state income tax expense included in each utility's cost of service would be deemed to be collected on a provisional basis (subject to refund) beginning January 1, 2014.

Regulatory Assets and Regulatory Liabilities

The Company's cost-based, rate-regulated utilities recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all of our regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2013**	**2012**
Regulatory Assets:		
Accumulated deferred income taxes	$ 259	$ 254
Under-collections—electric fuel adjustment clause	18	66
Environmental remediation costs	41	44
AROs and related funding	368	319
Franchise agreements	31	36
Deferred employee benefit plan costs	238	460
Planned major maintenance	—	6
Deferred losses on interest rate derivatives	124	151
Deferred pollution control costs	37	38
Unrecovered plant	145	20
DSM Programs	51	27
Other	48	43
Total Regulatory Assets	$ 1,360	$ 1,464
Regulatory Liabilities:		
Accumulated deferred income taxes	$ 24	$ 21
Asset removal costs	695	692
Storm damage reserve	27	27
Monetization of bankruptcy claim	29	32
Deferred gains on interest rate derivatives	181	110
Planned major maintenance	10	—
Total Regulatory Liabilities	$ 966	$ 882

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by the Company, and are expected to be recovered over periods of up to approximately 26 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on a SCPSC order, SCE&G began amortizing these amounts through cost of service rates in February 2003 over approximately 20 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In connection with the December 2012 rate order, approximately $63 million of deferred pension costs for electric operations are being recovered through utility rates over approximately 30 years. In connection with the October 2013 RSA order, approximately $14 million of deferred pension costs for gas operations are being recovered through utility rates over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil-fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects $18.4 million annually for such equipment maintenance. Through December 31, 2012, nuclear refueling charges were accrued during each 18-month refueling outage cycle as a component of cost of service. In connection with the December 2012 rate order, effective January 1, 2013, SCE&G collects and accrues $16.8 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt, up to approximately 30 years. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the installation of scrubbers at Wateree and Williams Stations pursuant to specific regulatory orders. Such costs are being recovered through utility rates over periods up to 30 years.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives, or up to approximately 14 years. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represents deferred costs and certain unrecovered lost revenue associated with SCE&G's Demand Side Management programs. Deferred costs are currently being recovered over 5 years through a SCPSC approved rider. Unrecovered lost revenue is to be recovered over periods not to exceed 24 months from date of deferral. See Rate Matters - Electric Base Rates above for details regarding a 2014 filing with the SCPSC regarding recovery of these deferred costs and unrecovered lost revenue.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the non-legal obligation to remove assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely.

The monetization of bankruptcy claim represents proceeds from the sale of a bankruptcy claim which are expected to be amortized into operating revenue through February 2024.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. COMMON EQUITY

The Company's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCANA's junior subordinated indenture (relating to the Hybrids), SCE&G's bond indenture (relating to the Bonds) and PSNC Energy's note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013 and 2012, approximately $63.1 million and $61.0 million of retained earnings, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

Cash dividends on SCANA's common stock were declared during 2013, 2012 and 2011 at an annual rate per share of $2.03, $1.98 and $1.94, respectively.

The accumulated balances related to each component of accumulated other comprehensive income (loss), net of tax, were as follows:

Millions of Dollars	Gains (Losses) on Cash Flow Hedges	Deferred Employee Benefit Plans	Accumulated Other Comprehensive Income (Loss)
Accumulated Other Comprehensive Loss as of January 1, 2012	$ (81)	$ (13)	$ (94)
Other comprehensive income (loss)	11	(3)	8
Accumulated Other Comprehensive Loss as of December 31, 2012	(70)	(16)	(86)
Other comprehensive income	18	8	26
Accumulated Other Comprehensive Loss as of December 31, 2013	$ (52)	$ (8)	$ (60)

Authorized shares of common stock were 200 million as of December 31, 2013 and 2012.

SCANA issued common stock valued at $100.9 million, $97.7 million and $97.8 million (when issued) during the years ended December 31, 2013, 2012 and 2011, respectively, which was satisfied using original issue shares, through various compensation and dividend reinvestment plans, including the Stock Purchase Savings Plan.

In March 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196.2 million.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average interest rates and maturities at December 31 is as follows:

Dollars in millions	Maturity	2013 Balance	2013 Rate	2012 Balance	2012 Rate
Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.02%
Senior Notes (unsecured) (a)	2034	92	0.94%	96	1.01%
First Mortgage Bonds (secured)	2018 - 2042	3,540	5.60%	3,290	5.66%
Junior Subordinated Notes (unsecured) (b)	2065	150	7.92%	150	7.70%
GENCO Notes (secured)	2018 - 2024	233	5.89%	240	5.87%
Industrial and Pollution Control Bonds (c)	2014 - 2038	158	3.83%	161	4.32%
Senior Debentures	2020- 2026	350	5.93%	350	5.90%
Nuclear Fuel Financing	2016	100	0.78%	—	—
Other	2014 - 2027	20	2.73%	27	2.39%
Total debt		5,443		5,114	
Current maturities of long-term debt		(54)		(172)	
Unamortized premium (discount)		6		7	
Total long-term debt, net		$ 5,395		$ 4,949	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.47%)
(b) May be extended through 2080
(c) Includes variable rate debt of $67.8 million at December 31, 2013 (rate of 0.11%) and 2012 (rate of 0.17%) which are hedged by fixed swaps.

The annual amounts of long-term debt maturities for the years 2014 through 2018 are summarized as follows:

Year	Millions of dollars
2014	$ 54
2015	15
2016	114
2017	13
2018	722

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.63% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027. The borrowings refinanced by these 2013 issuances are classified within Long-term Debt, Net in the consolidated balance sheet.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042, which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

In January 2012, SCANA issued $250 million of 4.125% medium term notes due February 1, 2022. Proceeds from the sale were used to retire SCANA's $250 million 6.25% medium term notes due February 1, 2012.

Substantially all of SCE&G's and GENCO's electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Lines of Credit and Short-Term Borrowings

At December 31, 2013 and 2012, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC advances, commercial paper, and LOC-supported letter of credit obligations:

	SCANA		SCE&G		PSNC Energy	
Millions of dollars	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Lines of Credit:						
Total committed long-term	$ 300	$ 300	$ 1,400	$ 1,400	$ 100	$ 100
LOC advances	—	—	—	—	—	—
Weighted average interest rate	—	—	—	—	—	—
Outstanding commercial paper (270 or fewer days)	$ 125	$ 142	$ 251	$ 449	—	$ 32
Weighted average interest rate	0.39%	0.58%	0.27%	0.42%	—	0.44%
Letters of credit supported by LOC	$ 3	$ 3	$ 0.3	$ 0.3	—	—
Available	$ 172	$ 155	$ 1,149	$ 951	$ 100	$ 68

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to five-year credit agreements in the amounts of $300 million, $1.2 billion (of which $500 million relates to Fuel Company) and $100 million, respectively. In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In October 2013, the term of each of these credit agreements was extended by one year, such that the five-year agreements expire in October 2018, and the three-year agreement expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1.8 billion credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9%, and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. The letters of credit expire, subject to renewal, in the fourth quarter of 2014.

The Company pays fees to the banks as compensation for maintaining committed lines of credit. Such fees were not material in any period presented.

5. INCOME TAXES

Components of income tax expense for 2013, 2012 and 2011 are as follows:

Millions of dollars	2013	2012	2011
Current taxes:			
Federal	$ 161	$ 103	$ 52
State	17	10	10
Total current taxes	178	113	62
Deferred taxes, net:			
Federal	39	72	122
State	10	14	12
Total deferred taxes	49	86	134
Investment tax credits:			
Amortization of amounts deferred-state	(1)	(14)	(25)
Amortization of amounts deferred-federal	(3)	(3)	(3)
Total investment tax credits	(4)	(17)	(28)
Total income tax expense	$ 223	$ 182	$ 168

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2013	2012	2011
Net income	$ 471	$ 420	$ 387
Income tax expense	223	182	168
Total pre-tax income	$ 694	$ 602	$ 555
Income taxes on above at statutory federal income tax rate	$ 243	$ 211	$ 194
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	22	19	15
State investment tax credits (less federal income tax effect)	(5)	(13)	(16)
Allowance for equity funds used during construction	(9)	(8)	(5)
Deductible dividends—Stock Purchase Savings Plan	(10)	(9)	(9)
Amortization of federal investment tax credits	(3)	(3)	(3)
Section 45 tax credits	(5)	(5)	(2)
Domestic production activities deduction	(11)	(9)	(6)
Other differences, net	1	(1)	—
Total income tax expense	$ 223	$ 182	$ 168

The tax effects of significant temporary differences comprising the Company's net deferred tax liability at December 31, 2013 and 2012 are as follows:

Millions of dollars	2013	2012
Deferred tax assets:		
Nondeductible accruals	$ 84	$ 143
Asset retirement obligation, including nuclear decommissioning	220	214
Financial instruments	32	43
Unamortized investment tax credits	19	22
Regulatory liability, net gain on interest rate derivative contracts settlement	27	—
Unbilled revenue	—	14
Monetization of bankruptcy claim	11	12
Other	13	15
Total deferred tax assets	406	463
Deferred tax liabilities:		
Property, plant and equipment	$ 1,765	$ 1,718
Deferred employee benefit plan costs	63	148
Regulatory asset-asset retirement obligation	121	113
Deferred fuel costs	25	48
Regulatory asset, unrecovered plant	55	7
Other	84	71
Total deferred tax liabilities	2,113	2,105
Net deferred tax liability	$ 1,707	$ 1,642

During the third quarter of 2013, the State of North Carolina passed legislation that lowered the state corporate income tax rate from 6.9% to 6.0% in 2014 and 5.0% in 2015. In connection with this change in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The change in income tax rates did not and is not expected to have a material impact on the Company's financial position, results of operations or cash flows. Additionally, during the third quarter of 2013, the IRS issued final regulations regarding the capitalization of certain costs for income tax purposes and re-proposed certain other related regulations (collectively referred to as tangible personal property regulations). Related IRS revenue procedures were then issued on January 24, 2014. These regulations did not and are not expected to, have a material impact on the Company's financial position, results of operations or cash flows.

The Company files a consolidated federal income tax return, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company's federal returns through 2004, and the Company's federal returns through 2007 are closed for additional assessment. With few exceptions, the Company is no longer subject to state and local income tax examinations by tax authorities for years before 2009.

Changes to Unrecognized Tax Benefits

Millions of dollars	2013	2012	2011
Unrecognized tax benefits, January 1	—	$ 38	$ 36
Gross increases—uncertain tax positions in prior period	—	—	5
Gross decreases—uncertain tax positions in prior period	—	(38)	(8)
Gross increases—current period uncertain tax positions	$ 3	—	5
Settlements	—	—	—
Lapse of statute of limitations	—	—	—
Unrecognized tax benefits, December 31	$ 3	$ —	$ 38

In connection with the change in method of tax accounting for certain repair costs in prior years, the Company had previously recorded an unrecognized tax benefit. During the first quarter of 2012, the publication of new administrative guidance from the IRS allowed the Company to recognize this benefit. Since this change was primarily a temporary difference, the recognition of this benefit did not have a significant effect on the Company's effective tax rate.

During 2013, the Company amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, the Company recorded an unrecognized tax benefit of $3 million. If recognized, this tax benefit would affect the Company's effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $5 million within the next 12 months. No other material changes in the status of the Company's tax positions have occurred through December 31, 2013.

The Company recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit in 2012, during 2012 the Company reversed $2 million of interest expense which had been accrued during 2011. The Company has not recorded interest expense or penalties associated with the 2013 uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. The Company recognizes changes in the fair value of derivative instruments either in earnings, as a component of other comprehensive income (loss) or, for regulated subsidiaries, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Company's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to the Audit Committee's attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statement of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and swaps and NYMEX futures and options. PSNC Energy's tariffs also include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SEMI, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

The Company may use interest rate swaps to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which the Company synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, the Company may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For the holding company or nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders issued in 2013, interest rate derivatives entered into by SCE&G after October 2013 are no longer designated as cash flow hedges, and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Upon settlement, losses on swaps will be amortized over the lives of related debt issuances, and gains may be applied to under-collected fuel, be amortized to interest expense or applied as otherwise directed by the SCPSC. As discussed in Note 2, in these orders, the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)			
Hedge designation	**Gas Distribution**	**Retail Gas Marketing**	**Energy Marketing**	**Total**
As of December 31, 2013				
Commodity	6,070,000	6,726,000	2,560,000	15,356,000
Energy Management (a)	—	—	27,359,958	27,359,958
Total (a)	6,070,000	6,726,000	29,919,958	42,715,958
As of December 31, 2012				
Commodity	5,170,000	6,490,000	4,877,000	16,537,000
Energy Management (b)	—	—	31,763,275	31,763,275
Total (b)	5,170,000	6,490,000	36,640,275	48,300,275

(a) Includes an aggregate 348,453 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 3,500,000 MMBTU related to basis swap contracts in Energy Marketing.

The Company was party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $128.8 million at December 31, 2013, and $1.1 billion at December 31, 2012. The Company was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.3 billion and $0.0 million at December 31, 2013 and 2012, respectively.

The fair value of energy-related derivatives and interest rate derivatives was reflected in the consolidated balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
Millions of dollars	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of December 31, 2013				
Derivatives designated as hedging instruments				
Interest rate contracts			Other current liabilities	$ 5
			Other deferred credits and other liabilities	14
Commodity contracts	Prepayments and other	$ 2		
Total		$ 2		$ 19
Derivatives not designated as hedging instruments				
Interest rate contracts	Prepayments and other	$ 13	Other current liabilities	$ 1
	Other deferred debits and other assets	19		
Commodity contracts	Prepayments and other	2		
Energy management contracts	Prepayments and other	4	Other current liabilities	4
	Other deferred debits and other assets	4	Other deferred credits and other liabilities	4
Total		$ 42		$ 9
As of December 31, 2012				
Derivatives designated as hedging instruments				
Interest rate contracts	Prepayments and other	$ 42	Other current liabilities	$ 70
	Other deferred debits and other assets	31	Other deferred credits and other liabilities	36
Commodity contracts	Prepayments and other	1	Other current liabilities	4
Total		$ 74		$ 110
Derivatives not designated as hedging instruments				
Commodity contracts	Prepayments and other	$ 1		
Energy management contracts	Prepayments and other	7	Prepayments and other	$ 1
	Other deferred debits and other assets	6	Other current liabilities	6
			Other deferred debits and other assets	6
Total		$ 14		$ 13

The effect of derivative instruments on the consolidated statements of income is as follows:

Fair Value Hedges

With regard to interest rate swaps designated as fair value hedges, any gains or losses related to the swaps or the fixed rate debt are recognized in current earnings within interest expense. The Company had no interest rate swaps designated as fair value hedges for any period presented, and the amortization of deferred gains on previously terminated swaps were not significant during any period presented.

Cash Flow Hedges

Derivatives in Cash Flow Hedging Relationships

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)		Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount	
Year Ended December 31, 2013					
Interest rate contracts	$	106	Interest expense	$	(3)
Year Ended December 31, 2012					
Interest rate contracts	$	84	Interest expense	$	(3)
Year Ended December 31, 2011					
Interest rate contracts	$	(76)	Interest expense	$	(3)

Millions of dollars	Gain or (Loss) Recognized in OCI, net of tax (Effective Portion)		Loss Reclassified from Accumulated OCI into Income, net of tax (Effective Portion) Location	Amount	
Year Ended December 31, 2013					
Interest rate contracts	$	5	Interest expense	$	(8)
Commodity contracts		2	Gas purchased for resale		(3)
Total	$	7		$	(11)
Year Ended December 31, 2012					
Interest rate contracts	$	(4)	Interest expense	$	(6)
Commodity contracts		(4)	Gas purchased for resale		(13)
Total	$	(8)		$	(19)
Year Ended December 31, 2011					
Interest rate contracts	$	(42)	Interest expense	$	(4)
Commodity contracts		(16)	Gas purchased for resale		(9)
Total	$	(58)		$	(13)

As of December 31, 2013, the Company expects that during the next 12 months reclassifications from accumulated other comprehensive loss to earnings arising from cash flow hedges will include approximately $1.0 million as an increase to gas cost and approximately $7.0 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2013, all of the Company's commodity cash flow hedges settle by their terms before the end of 2016.

Hedge Ineffectiveness

Other losses recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in 2013 and 2012 and were $(1.1) million, net of tax, in 2011. These amounts are recorded within interest expense on the consolidated statements of income.

Derivatives Not Designated as Hedging Instruments

Millions of dollars	Loss Recognized in Income Location	Year Ended December 31, 2013	2012		2011	
Commodity contracts	Gas purchased for resale	—	$	(1)	$	(2)

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income	
		Location	Amount
Year Ended December 31, 2013			
Interest rate contracts	$ 39	Other income	$ 50
Year Ended December 31, 2012			
Interest rate contracts	$ —		$ —
Year Ended December 31, 2011			
Interest rate contracts	$ —		$ —

The gains reclassified to other income of $50 million offset revenue reductions as previously described herein and in Note 2.

Credit Risk Considerations

The Company limits credit risk in its commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, the Company uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. The Company uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with the Company's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of the Company’s derivative instruments contain contingent provisions that require the Company to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2013 and 2012, the Company had posted $26.8 million and $78.3 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months is recorded in Prepayments and other on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and 2012, the Company would have been required to post an additional $0.0 million and $26.2 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2013 and 2012, are $25.2 million and $104.5 million, respectively.

In addition, as of December 31, 2013 and December 31, 2012, the Company has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and December 31, 2012, the Company could request $34.1 million and $32.1 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2013 and December 31, 2012 is $34.1 million and $32.1 million, respectively. In addition, at December 31, 2013, the Company could have called on letters of credit in the amount of $ 6 million related to $6 million in commodity derivatives that are in a net asset position, compared to letters of credit of $10 million related to derivatives of $13 million at December 31, 2012, if all the contingent features underlying these instruments had been fully triggered.

Information related to the Company's offsetting derivative assets follows:

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2013						
Interest rate	$ 32	—	$ 32	$ (1)	—	$ 31
Commodity	4	—	4	—	—	4
Energy Management	8	—	8	—	—	8
Total	$ 44	—	$ 44	$ (1)	—	$ 43
Balance sheet location	Prepayments and other		$ 21			
	Other deferred debits and other assets		23			
	Total		$ 44			
As of December 31, 2012						
Interest rate	$ 73	—	$ 73	$ (17)	—	$ 56
Commodity	2	—	2	—	—	2
Energy Management	13	$ (1)	12	—	—	12
Total	$ 88	$ (1)	$ 87	$ (17)	—	$ 70
Balance sheet location	Prepayments and other		$ 50			
	Other deferred debits and other assets		37			
	Total		$ 87			

Information related to the Company's offsetting derivative liabilities follows:

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2013						
Interest rate	$ 20	—	$ 20	$ (1)	$ 19	—
Energy Management	8	—	8	—	6	$ 2
Total	$ 28	—	$ 28	$ (1)	$ 25	$ 2
Balance sheet location	Other current liabilities		$ 10			
	Other deferred credits and other liabilities		18			
	Total		$ 28			

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2012						
Interest rate	$ 106	—	$ 106	$ (17)	$ 67	$ 22
Commodity	4	—	4	—	—	4
Energy Management	13	$ (1)	12	—	11	1
Total	$ 123	$ (1)	$ 122	$ (17)	$ 78	$ 27

Balance sheet location	Other current liabilities	$ 80
	Other deferred credits and other liabilities	42
	Total	$ 122

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

The Company values available for sale securities using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. The Company's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	As of December 31, 2013 Level 1	As of December 31, 2013 Level 2	As of December 31, 2012 Level 1	As of December 31, 2012 Level 2
Assets:				
Available for sale securities	$ 9	—	$ 6	—
Interest rate contracts	—	$ 32	—	$ 73
Commodity contracts	2	2	1	1
Energy management contracts	1	7	—	13
Liabilities:				
Interest rate contracts	—	20	—	106
Commodity contracts	—	—	—	4
Energy management contracts	—	12	1	15

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2013 and December 31, 2012 were as follows:

Millions of dollars	As of December 31, 2013 Carrying Amount	As of December 31, 2013 Estimated Fair Value	As of December 31, 2012 Carrying Amount	As of December 31, 2012 Estimated Fair Value
Long-term debt	$ 5,449.3	$ 5,916.3	$ 5,121.0	$ 6,115.0

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

The Company sponsors a noncontributory defined benefit pension plan covering substantially all regular, full-time employees hired before January 1, 2014. In the third quarter of 2013, the Company amended its pension plan such that benefits are no longer offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. The Company's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The Company's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all employees hired from January 1, 2000 through December 31, 2013. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, the Company provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost. Employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them. The Company provides life insurance benefits to retirees at no charge, except that employees hired after December 31, 2010 are ineligible for retiree life insurance benefits. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2013**	**2012**	**2013**	**2012**
Benefit obligation, January 1	$ 931.6	$ 830.1	$ 265.3	$ 226.1
Service cost	21.8	19.6	5.9	4.8
Interest cost	38.5	43.0	11.1	11.9
Plan participants' contributions	—	—	2.6	2.9
Actuarial (gain) loss	(83.4)	96.5	(35.1)	33.4
Benefits paid	(60.0)	(57.6)	(11.8)	(13.8)
Curtailment	(25.5)	—	—	—
Benefit obligation, December 31	$ 823.0	$ 931.6	$ 238.0	$ 265.3

The accumulated benefit obligation for pension benefits was $ 796.4 million at the end of 2013 and $874.6 million at the end of 2012. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Annual discount rate used to determine benefit obligation	5.03%	4.10%	5.19%	4.19%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.75%	3.75%	3.75%

A 7.4% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation at December 31, 2013 by $1.3 million and 2012 by $1.7 million. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation at December 31, 2013 by $1.2 million and 2012 by $1.5 million.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Fair value of plan assets	$ 870.0	$ 799.1	—	—
Benefit obligation	823.0	931.6	$ 238.0	$ 265.3
Funded status	$ 47.0	$ (132.5)	$ (238.0)	$ (265.3)

Amounts recognized on the consolidated balance sheets consist of:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Current liability	—	—	$ (11.5)	$ (11.0)
Noncurrent asset	$ 47.0	—	—	—
Noncurrent liability	—	$ (132.5)	(226.5)	(254.3)

Amounts recognized in accumulated other comprehensive loss (a component of common equity) as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$ 5.2	$ 10.7	$ 1.7	$ 3.7
Prior service cost	0.5	1.0	0.1	0.1
Transition obligation	—	—	—	0.1
Total	$ 5.7	$ 11.7	$ 1.8	$ 3.9

Amounts recognized in regulatory assets as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$ 124.8	$ 297.0	$ 24.4	$ 57.0
Prior service cost	12.8	26.9	0.9	1.5
Transition obligation	—	—	—	0.2
Total	$ 137.6	$ 323.9	$ 25.3	$ 58.7

In connection with the joint ownership of Summer Station, as of December 31, 2013 and 2012, the Company recorded within deferred debits $14.1 million and $26.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2013 and 2012, the Company also recorded within deferred debits $12.6 million and $14.7 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2013	2012
Fair value of plan assets, January 1	$ 799.1	$ 755.0
Actual return on plan assets	130.9	101.7
Benefits paid	(60.0)	(57.6)
Fair value of plan assets, December 31	$ 870.0	$ 799.1

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan is closed to new entrants effective January 1, 2014, and benefit accruals will cease effective January 1, 2024. In addition, during 2013, the Company adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs in connection with the amendments to the plan.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The Company's pension plan asset allocation at December 31, 2013 and 2012 and the target allocation for 2014 are as follows:

	Percentage of Plan Assets		
	Target Allocation	At December 31,	
Asset Category	2014	2013	2012
Equity Securities	58%	59%	66%
Fixed Income	33%	32%	25%
Hedge Funds	9%	9%	9%

For 2014, the expected long-term rate of return on assets will be 8.00%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes an asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment policy adopted for 2014.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2013 and 2012, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	Fair Value Measurements at Reporting Date Using							
	December 31, 2013				*December 31, 2012*			
Common stock	$ 332	$ 332			$ 319	$ 319		
Preferred stock	1	1			1	1		
Mutual funds	305	20	$ 285		246	12	$ 234	
Short-term investment vehicles	19		19		20		20	
US Treasury securities	33		33		42		42	
Corporate debt securities	53		53		56		56	
Loans secured by mortgages	12		12		11		11	
Municipals	4		4		4		4	
Limited partnerships	35	1	34		30	1	29	
Multi-strategy hedge funds	76			$ 76	70			$ 70
	$ 870	$ 354	$ 440	$ 76	$ 799	$ 333	$ 396	$ 70

There were no transfers of fair value amounts into or out of Level 1, 2 or 3 during 2013 or 2012.

The pension plan values common stock, preferred stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

Millions of dollars	Fair Value Measurements Level 3 2013	2012
Beginning Balance	$ 70	$ 65
Unrealized gains included in changes in net assets	6	5
Purchases, issuances, and settlements	—	—
Ending Balance	$ 76	$ 70

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from the Company's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2014	$ 61.5	$ 11.7
2015	61.2	12.6
2016	63.8	13.4
2017	65.8	14.1
2018	66.1	14.7
2019-2023	338.4	82.4

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, the Company does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

The Company records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2013	2012	2011	2013	2012	2011
Service cost	$ 21.8	$ 19.6	$ 18.3	$ 5.9	$ 4.8	$ 4.3
Interest cost	38.5	43.0	43.5	11.1	11.9	12.2
Expected return on assets	(61.4)	(59.5)	(63.7)	n/a	n/a	n/a
Prior service cost amortization	6.0	7.0	7.0	0.7	0.9	1.0
Amortization of actuarial losses	16.9	18.4	12.2	3.3	1.4	0.4
Transition obligation amortization	—	—	—	0.3	0.7	0.7
Curtailment loss	9.9	—	—	—	—	—
Net periodic benefit cost	$ 31.7	$ 28.5	$ 17.3	$ 21.3	$ 19.7	$ 18.6

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension cost related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension costs related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2).

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2013	2012	2011	2013	2012	2011
Current year actuarial (gain) loss	$ (5.0)	$ 1.7	$ 2.9	$ (1.8)	$ 2.0	$ 0.4
Amortization of actuarial losses	(0.5)	(0.6)	(0.4)	(0.2)	—	—
Amortization of prior service cost	(0.2)	(0.2)	(0.2)	—	—	(0.1)
Prior service cost (credit)	(0.3)	—	—	—	—	—
Amortization of transition obligation	—	—	—	(0.1)	(0.1)	(0.1)
Total recognized in other comprehensive income	$ (6.0)	$ 0.9	$ 2.3	$ (2.1)	$ 1.9	$ 0.2

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2013	2012	2011	2013	2012	2011
Current year actuarial (gain) loss	$ (157.5)	$ 45.0	$ 70.9	$ (29.9)	$ 31.4	$ 6.0
Amortization of actuarial losses	(14.7)	(16.0)	(10.6)	(2.7)	(1.2)	(0.3)
Amortization of prior service cost	(5.2)	(6.4)	(6.4)	(0.6)	(0.8)	(0.9)
Prior service cost (credit)	(8.9)	—	—	—	—	—
Amortization of transition obligation	—	—	—	(0.2)	(0.5)	(0.5)
Total recognized in regulatory assets	$ (186.3)	$ 22.6	$ 53.9	$ (33.4)	$ 28.9	$ 4.3

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	4.10%/5.07%	5.25%	5.56%	4.19%	5.35%	5.72%
Expected return on plan assets	8.00%	8.25%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.75%/3.00%	4.00%	4.00%	3.75%	4.00%	4.00%
Health care cost trend rate	n/a	n/a	n/a	7.80%	8.20%	8.00%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2017

Net periodic benefit cost for the period through September 1, 2013 was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 0.2	—
Prior service cost	0.1	—
Total	$ 0.3	—

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2014 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 4.3	$ 0.4
Prior service cost	3.5	0.3
Total	$ 7.8	$ 0.7

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

Stock Purchase Savings Plan

The Company sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. The Company provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan for 2013, 2012 and 2011 were $23.4 million, $22.3 million and $21.8 million, respectively, and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation costs related to share-based payment transactions are required to be recognized in the financial statements. With limited exceptions, including those liability awards discussed below, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

Liability Awards

The 2011-2013, 2012-2014 and 2013-2015 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three -year performance cycle. In each of the performance cycles, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of retirement or termination of employment prior to the end of the cycle, subject to exceptions for death, disability or change in control. The remaining 80% of the award was granted in performance shares. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in "GAAP-adjusted net earnings per share from operations" (weighted 50%).

Compensation cost of liability awards is recognized over their respective three -year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2011-2013 performance cycle were paid in cash at SCANA's discretion in February 2014. Cash-settled liabilities related to prior program cycles were paid totaling $ 12.2 million in 2013, $11.8 million in 2012, and $13.6 million in 2011.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling $ 8.7 million in 2013, $15.0 million in 2012 and $6.1 million in 2011. Fair value adjustments resulted in capitalized compensation costs of $ 1.4 million in 2013, $2.7 million in 2012 and $0.9 million in 2011.

Equity Awards

No equity awards were made during any period presented, and the effects of previous such awards on the Company's results of operations, cash flows and financial position were not significant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $41.6 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Company's results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC.

SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. Under the terms of the agreement SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in a revised rates filing under the BLRA.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules

CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution of these specific claims is discussed in Note 2. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that the revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units’ reactor buildings (March 2013 for the first New

Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification.

Environmental

SCE&G

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. The Company also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on the Company, if any. The Company expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed the Company to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. The Company will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in the Company's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014. The Company is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of the Company. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While the Company cannot predict how extensive the regulations will be, the Company believes that any additional costs imposed by such regulations would be recoverable through rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2013, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017, and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2017 and will cost an additional $20.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

PSNC Energy

PSNC Energy is responsible for environmental clean-up at five sites in North Carolina on which MGP residuals are present or suspected. Actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $2.8 million, the estimated remaining liability at December 31, 2013. PSNC Energy expects to recover through rates any cost allocable to PSNC Energy arising from the remediation of these sites.

Claims and Litigation

The Company is engaged in various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on the Company's results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company is obligated under various operating leases for vehicles, office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $14.8 million in 2013, $14.8 million in 2012 and $15.8 million in 2011. Future minimum rental payments under such leases are as follows:

	Millions of dollars
2014	$ 7
2015	6
2016	4
2017	2
2018	1
Thereafter	21
Total	$ 41

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2013, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.6 billion.

Asset Retirement Obligations

The Company recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that results from their acquisition, construction, development and normal operation relate primarily to the Company’s regulated utility operations. As of December 31, 2013, the Company has recorded AROs of approximately $191 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $385 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars	2013	2012
Beginning balance	$ 561	$ 473
Liabilities incurred	6	—
Liabilities settled	(4)	(5)
Accretion expense	25	24
Revisions in estimated cash flows	(12)	69
Ending balance	$ 576	$ 561

11. AFFILIATED TRANSACTIONS

The Company received cash distributions from equity-method investees of $10.4 million in 2013, $12.5 million in 2012 and $5.5 million in 2011 . The Company made investments in equity-method investees of $5.2 million in 2013, $10.6 million in 2012 and $13.6 million in 2011.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's receivable from this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's payable to this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's total purchases from this affiliate were $134.2 million in 2013 and $111.6 million in 2012. SCE&G's total sales to this affiliate were $133.6 million in 2013 and $111.1 million in 2012.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1. The Company records intersegment sales and transfers of electricity and gas based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations is primarily engaged in the generation, transmission and distribution of electricity, and is regulated by the SCPSC and FERC.

Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, is engaged in the purchase and sale, primarily at retail, of natural gas. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively.

Retail Gas Marketing markets natural gas in Georgia and is regulated as a marketer by the GPSC. Energy Marketing markets natural gas to industrial and large commercial customers and municipalities, primarily in the Southeast.

All Other is comprised of other direct and indirect wholly-owned subsidiaries of the Company. One of these subsidiaries operates a FERC-regulated interstate pipeline company and the other subsidiaries conduct nonregulated operations in energy-related and telecommunications industries. None of these subsidiaries met the quantitative thresholds for determining reportable segments during any period reported.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. The marketing segments differ from each other in their respective markets and customer type.

Disclosure of Reportable Segments (Millions of dollars)

		Electric Operations		Gas Distribution		Retail Gas Marketing		Energy Marketing		All Other		Adjustments/ Eliminations		Consolidated Total
2013														
External Revenue	$	2,423	$	942	$	465	$	652	$	40	$	(27)	$	4,495
Intersegment Revenue		6		1		—		167		416		(590)		—
Operating Income		679		153		—		n/a		27		51		910
Interest Expense		19		22		1		—		4		251		297
Depreciation and Amortization		297		70		3		—		26		(18)		378
Income Tax Expense		6		33		15		4		14		151		223
Net Income		n/a		n/a		24		6		(2)		443		471
Segment Assets		9,488		2,340		172		133		1,378		1,653		15,164
Expenditures for Assets		907		140		—		1		31		27		1,106
Deferred Tax Assets		10		27		8		2		14		(61)		—
2012														
External Revenue	$	2,446	$	764	$	413	$	543	$	45	$	(35)	$	4,176
Intersegment Revenue		7		1		—		125		416		(549)		—
Operating Income		668		141		n/a		n/a		22		28		859
Interest Expense		21		23		1		—		3		247		295
Depreciation and Amortization		278		67		3		—		25		(17)		356
Income Tax Expense		7		32		7		3		15		118		182
Net Income		n/a		n/a		11		5		1		403		420
Segment Assets		8,989		2,292		153		122		1,415		1,645		14,616
Expenditures for Assets		999		123		—		1		14		(60)		1,077
Deferred Tax Assets		9		26		10		4		17		(55)		11
2011														
External Revenue	$	2,424	$	840	$	479	$	657	$	41	$	(32)	$	4,409
Intersegment Revenue		8		1		—		188		406		(603)		—
Operating Income		616		132		n/a		n/a		18		47		813
Interest Expense		23		24		1		—		3		233		284
Depreciation and Amortization		271		65		3		—		25		(18)		346
Income Tax Expense		5		30		16		3		10		104		168
Net Income		n/a		n/a		24		4		(6)		365		387
Segment Assets		8,222		2,179		185		114		1,377		1,457		13,534
Expenditures for Assets		806		140		—		1		17		(18)		946
Deferred Tax Assets		9		12		9		9		17		(30)		26

Management uses operating income to measure segment profitability for SCE&G and other regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, the Company does not allocate interest charges, income tax expense or assets other than utility plant to its segments. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Interest income is not reported by segment and is not material. The Company's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of the Company's regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the totals from SCANA or SCE&G that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to asset retirement obligations. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2013					
Total operating revenues	$ 1,311	$ 1,016	$ 1,051	$ 1,117	$ 4,495
Operating income	293	189	255	173	910
Net income	151	85	131	104	471
Basic earnings per share	1.13	.60	.94	.73	3.40
Diluted earnings per share	1.11	.60	.94	.73	3.39
2012					
Total operating revenues	$ 1,107	$ 908	$ 1,038	$ 1,123	$ 4,176
Operating income	238	171	238	212	859
Net income	121	72	122	105	420
Basic earnings per share	.93	.55	.93	.79	3.20
Diluted earnings per share	.91	.54	.91	.78	3.15

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCE&G is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, and transportation of natural gas. SCE&G's business is subject to seasonal fluctuations. Generally, sales of electricity are higher during the summer and winter months because of air-conditioning and heating requirements, and sales of natural gas are greater in the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 22,600 square miles.

Key Earnings Drivers and Outlook

During 2013, economic growth continued to improve in the southeast. Significant industrial announcements in SCE&G's service territory were made during the year, and announcements made in previous years began to materialize. In addition, the Port of Charleston continues to see increased traffic, with container volume up 5.7% over 2012. SCE&G's residential and commercial customer growth rates also were positive. At December 31, 2013, a preliminary estimate of seasonally adjusted unemployment for South Carolina was 6.6%. Though improved from the 8.6% unemployment rate at December 31, 2012, the improvement may be due in part to people leaving the workforce. Nationwide the civilian labor force was 62.8% at December 31, 2013, matching a 35-year low.

Over the next five years, key earnings drivers for SCE&G will be additions to utility rate base, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

The electric operations segment is comprised of the electric operations of SCE&G, GENCO and Fuel Company, and is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina. At December 31, 2013 SCE&G provided electricity to approximately 678,000 customers. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results for electric operations are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control growth in costs. Through 2013, the effect of weather on operating results was largely mitigated by the eWNA; however, the eWNA was discontinued pursuant to an SCPSC order effective with the first billing cycle of January 2014. Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2013 was 10.25% for non-BLRA expenditures, and 11.0% for BLRA-related expenditures. As further described in Note 2 to the consolidated financial statements, SCE&G's allowed return on equity for non-BLRA expenditures was 10.7% prior to 2013. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units have an aggregate generating capacity (2012 summer rating) of 730 MW. As of December 31, 2013, three of these units have been retired. For additional information, see Note 1 and Note 2 to the consolidated financial statements.

New Nuclear Construction

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

SCE&G expects Unit 2 to be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest.

Significant recent developments in new nuclear construction include the following:

- In the first quarter of 2013, initial pouring of the Unit 2 nuclear island basemat was completed. The basemat provides a foundation for the containment vessel, shield building and auxiliary building that make up the nuclear island. The Unit 3 nuclear island basemat was completed in the fourth quarter of 2013.

- In April 2013, the 500-ton CR-10 module was set on the Unit 2 basemat. CR-10 supports the containment vessel. Construction of Unit 3's CR-10 module is currently underway.

- In May 2013, the containment vessel bottom head for Unit 2 was put in place. The containment vessel will house numerous reactor system components, such as the reactor vessel, steam generator and pressurizer. Work continues in building containment vessel rings that will be placed on the containment vessel bottom head for Unit 2.

- In September 2013, the reactor vessel cavity for Unit 2 (CA-04 module) was placed in the containment vessel bottom head. The reactor vessel cavity will house the reactor vessel, which in turn will house the fuel assemblies. The reactor vessel for Unit 2 is on-site.

- Fabrication has begun for Unit 2's steam generator and refueling canal module (CA-01 module) that will be located inside the containment vessel.

- Ring 1 of the Unit 2 containment vessel is scheduled to be placed on the containment vessel bottom head in the second quarter 2014. Ring 2 is scheduled to be placed in the fourth quarter of 2014.

- While progress has been made with production, quality assurance and quality control issues, the schedule for fabrication of sub-modules at the contractor facility remains a focus area for the project.

- During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

For additional information on these and other matters, see New Nuclear Construction Matters herein and Note 2 and Note 10 to the consolidated financial statements.

<u>Environmental</u>

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. New federal effluent limitation guidelines for steam electric generating units were published in the Federal Register on June 7, 2013, and the ELG Rule is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020. Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014, and Congress is expected to consider further amendments to the CWA.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 14, 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO.

The above environmental initiatives and other similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, Consolidated SCE&G cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on it, if any. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The Gas Distribution segment, comprised of the local distribution operations of SCE&G, is primarily engaged in the purchase, transportation and sale of natural gas to retail customers in portions of South Carolina. At December 31, 2013 this segment provided natural gas to approximately 329,000 customers.

Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control growth in costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25%.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact SCE&G's ability to retain large commercial and industrial customers. In addition, the production of shale gas in the United States has resulted in significantly lower prices for this commodity, and such prices are expected to continue for the foreseeable future.

RESULTS OF OPERATIONS

Net Income

Net income for Consolidated SCE&G was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Net income	$ 390.8	11.0%	$ 352.0	11.4%	$ 316.1

2013 vs 2012	Net income increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.
2012 vs 2011	Net income increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.

Dividends Declared

Consolidated SCE&G's Boards of Directors declared the following dividends on common stock (all of which was held by SCANA) during 2013 and 2012:

Declaration Date	Dividend Amount	Quarter Ended	Payment Date
February 20, 2013	$64.0 million	March 31, 2013	April 1, 2013
April 25, 2013	$63.8 million	June 30, 2013	July 1, 2013
July 31, 2013	$67.5 million	September 30, 2013	October 1, 2013
October 31, 2013	$61.7 million	December 31, 2013	January 1, 2014
February 15, 2012	$53.4 million	March 31, 2012	April 1, 2012
May 3, 2012	$54.1 million	June 30, 2012	July 1, 2012
August 2, 2012	$55.8 million	September 30, 2012	October 1, 2012
October 24, 2012	$45.6 million	December 31, 2012	January 1, 2013

When a dividend payment date falls on a weekend or holiday, the payment is made the following business day.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$ 2,430.5	(0.9)%	$ 2,453.1	0.9 %	$ 2,432.2
Less: Fuel used in generation	751.0	(11.0)%	844.2	(8.5)%	922.5
Purchased power	43.0	53.0 %	28.1	46.4 %	19.2
Margin	$ 1,636.5	3.5 %	$ 1,580.8	6.1 %	$ 1,490.5

2013 vs 2012 Margin increased primarily due to base rate increases under the BLRA of $54.2 million and higher electric base rates of $67.3 million approved in the December 2012 rate order. Additionally, pursuant to accounting orders of the SCPSC, 2013's electric margin reflects downward adjustments of $50.1 million to revenue. Such adjustments are fully offset by the recognition within other income of gains realized upon the settlement of certain derivative interest rate contracts, which had been deferred as regulatory liabilities. See Note 2 to the consolidated financial statements.

2012 vs 2011 Margin increased primarily by $54.4 million due to an increase in retail electric base rates approved by the SCPSC under the BLRA, by $3.7 million due to customer growth and by $11.0 million due to the expiration of a decrement rider approved in the 2010 retail electric base rate case.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2013	Change	2012	Change	2011
Residential	7,571	—	7,571	(8.0)%	8,232
Commercial	7,205	(1.2)%	7,291	(1.4)%	7,397
Industrial	6,000	2.8 %	5,836	(1.7)%	5,938
Other	581	(0.9)%	586	2.4 %	572
Total retail sales	21,357	0.3 %	21,284	(3.9)%	22,139
Wholesale	955	(63.2)%	2,595	26.6 %	2,049
Total	22,312	(6.6)%	23,879	(1.3)%	24,188

2013 vs 2012 Retail sales volume increased primarily due to customer growth and the effects of weather, partially offset by lower average use. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

2012 vs 2011 Retail sales volume decreased by 983 GWh primarily due to the effects of milder weather. The increase in wholesale sales is primarily due to higher contract utilization by a wholesale customer.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$ 414.4	16.5%	$ 355.6	(8.2)%	$ 387.4
Less: Gas purchased for resale	244.1	24.2%	196.6	(18.0)%	239.7
Margin	$ 170.3	7.1%	$ 159.0	7.7 %	$ 147.7

2013 vs 2012 Margin increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012, as well as residential and commercial customer growth.

2012 vs 2011 Margin increased $8.3 million due to the SCPSC-approved increases in retail gas base rates under the RSA which became effective with the first billing cycles of November 2011 and 2012.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2013	Change	2012	Change	2011
Residential	12,515	23.3%	10,153	(13.0)%	11,674
Commercial	12,786	9.1%	11,723	(2.9)%	12,071
Industrial	20,411	5.5%	19,341	14.0 %	16,963
Transportation gas	4,801	2.0%	4,707	7.6 %	4,376
Total	50,513	10.0%	45,924	1.9 %	45,084

2013 vs 2012 Total sales volumes increased primarily due to customer growth, increased industrial usage and the effects of weather.

2012 vs 2011 Residential and commercial sales volume decreased primarily due to milder weather. Industrial and transportation sales volumes increased due to the competitive price of gas versus alternate fuel sources.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Other operation and maintenance	$ 556.5	2.8%	$ 541.6	5.1%	$ 515.1
Depreciation and amortization	313.4	6.8%	293.4	2.6%	286.1
Other taxes	200.2	6.3%	188.3	3.2%	182.5

2013 vs 2012 Other operation and maintenance expenses increased by $16.7 million due to incremental expenses associated with the December 2012 SCPSC rate order and by $5.7 million due to higher electric generation, transmission and distribution expenses. These increases were partially offset by lower compensation costs of $10.1 million due to reduced headcount and lower incentive compensation accruals and by other general expenses. Depreciation and amortization expense increased $13.2 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 SCPSC rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes on net property additions.

2012 vs 2011 Other operation and maintenance expenses increased by $9.3 million due to higher generation, transmission and distribution expenses, by $1.7 million due to higher general expenses and by $14.2 million due to higher incentive compensation and other benefits. Depreciation and amortization expense increased primarily due to net property additions. Other taxes increased primarily due to higher property taxes on net property additions.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on Consolidated SCE&G's income statements and balance sheets as follows:

Millions of dollars	2013	Change	2012	Change	2011
Income Statement Impact:					
Employee benefit costs	$ 11.0	100.0%	—	—	—
Other expense	0.6	50.0 %	$ 0.4	100.0%	$ 0.2
Balance Sheet Impact:					
Increase in capital expenditures	6.4	12.3 %	5.7	67.6%	3.4
Component of amount receivable from Summer Station co-owner	2.5	13.6 %	2.2	83.3%	1.2
Increase in regulatory asset	5.5	(63.3)%	15.0	64.8%	9.1
Net periodic benefit cost	$ 26.0	11.6 %	$ 23.3	67.6%	$ 13.9

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension costs related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension cost related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2 to the consolidated financial statements). In 2013, such amortizations totaled approximately $2.0 million for electric operations and $0.2 million for gas operations.

Other Income (Expense)

Other income (expense) includes the results of certain non-utility activities. Components of other income (expense), were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Other income	$ 52.7	*	$ 0.4	(91.8)%	$ 4.9
Other expense	(17.5)	(2.2)%	(17.9)	51.7 %	(11.8)
Total	$ 35.2	*	$ (17.5)	*	$ (6.9)

* Greater than 100%

2013 vs 2012 Total other income (expense) increased primarily due to the recognition, pursuant to SCPSC accounting orders, of $50.1 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as regulatory liabilities. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

2012 vs 2011 Total other income (expense) decreased primarily due to higher non-utility related employee benefit costs in 2012.

AFC

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. Consolidated SCE&G includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 6.6% of income before income taxes in 2013, 6.3% in 2012 and 4.5% in 2011, respectively.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Interest on long-term debt, net	$ 206.8	3.0%	$ 200.7	5.1 %	$ 191.0
Other interest expense	10.5	7.1%	9.8	(27.4)%	13.5
Total	$ 217.3	3.2%	$ 210.5	2.9 %	$ 204.5

Interest on long-term debt increased in each year primarily due to increased long-term borrowings. Other interest expense increased in 2013 and decreased in 2012, primarily due to reductions in principal balances outstanding on short-term debt over the respective prior year and also decreased in 2012 due to the reversal in 2012 of interest which had been accrued in 2011 related to a tax uncertainty that was resolved (see Note 5 to the consolidated financial statements).

Income Taxes

Income tax expense increased in 2013 over 2012 and in 2012 over 2011 primarily due to increases in income before taxes. The increase in the effective tax rate in 2013 is principally attributable to lower recognition of EIZ Credits upon the completion of the amortization of certain such credits in 2012.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its contractual cash obligations will be met through internally generated funds and the incurrence of additional short- and long-term indebtedness. Consolidated SCE&G expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt. Consolidated SCE&G's ratio of earnings to fixed charges for the year ended December 31, 2013 was 3.48.

Consolidated SCE&G’s cash requirements arise primarily from its operational needs, funding its construction programs and payment of dividends to SCANA. The ability of Consolidated SCE&G to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental
regulations, will depend upon its ability to attract the necessary financial capital on reasonable terms. Consolidated SCE&G recovers the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and Consolidated SCE&G continues its ongoing construction program, Consolidated SCE&G expects to seek increases in rates. Consolidated SCE&G’s future financial position and results of operations will be affected by Consolidated SCE&G’s ability to obtain adequate and timely rate and other regulatory relief.

Cash outlays for property additions and construction expenditures, including nuclear fuel, net of AFC were $1.0 billion in 2013 and are estimated to be $1.5 billion in 2014.

Consolidated SCE&G’s current estimates of its capital expenditures for construction and nuclear fuel for 2014-2016, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2014	2015	2016
Consolidated SCE&G - Normal			
Generation	$ 136	$ 145	$ 112
Transmission & Distribution	230	280	258
Other	14	25	19
Gas	50	51	73
Common	9	7	10
Total Consolidated SCE&G - Normal	439	508	472
New Nuclear (including transmission)	950	905	667
Cash Requirements for Construction	1,389	1,413	1,139
Nuclear Fuel	67	30	147
Total Estimated Capital Expenditures	$ 1,456	$ 1,443	$ 1,286

Estimated capital expenditures for Nuclear Fuel in 2016 include approximately $53 million, which is SCE&G's share of nuclear fuel it acquired in 2013. This fuel has been recorded in utility plant and the corresponding obligation has been recorded in long-term debt on the consolidated balance sheet.

Consolidated SCE&G’s contractual cash obligations as of December 31, 2013 are summarized as follows:

Contractual Cash Obligations

	Payments due by period				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term and short-term debt including interest	$ 8,403	$ 510	$ 653	$ 1,090	$ 6,150
Capital leases	12	2	6	2	2
Operating leases	30	5	6	1	18
Purchase obligations	3,669	1,802	1,646	221	—
Other commercial commitments	2,524	527	713	571	713
Total	$ 14,638	$ 2,846	$ 3,024	$ 1,885	$ 6,883

Included in the table above in purchase obligations is SCE&G’s portion of a contractual agreement for the design and construction of the New Units at the Summer Station site. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent of the cost and receiving 55 percent of the output, and other joint owner (or owners) the remaining 45 percent. Also included in the table above is the estimated $500 million SCE&G expects it will cost to acquire an additional 5% ownership in the New Units as further described in New Nuclear Construction Matters.

Also included in purchase obligations are customary purchase orders under which SCE&G has the option to utilize certain vendors without the obligation to do so. SCE&G may terminate such arrangements without penalty.

Included in other commercial commitments are estimated obligations for coal and nuclear fuel purchases. SCE&G also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional asset retirement obligations that are not listed in the contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

At December 31, 2013, Consolidated SCE&G had posted $1.5 million in cash collateral for interest rate derivative contracts.

Financing Limits and Related Matters

Consolidated SCE&G’s issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including the SCPSC and FERC. Financing programs currently utilized by Consolidated SCE&G follow.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

In October 2013, the Consolidated SCE&G's existing committed LOCs were extended by one year. As a result, at December 31, 2013 SCE&G and Fuel Company were parties to five-year credit agreements in the amounts of $1.2 billion, (of which $500 million relates to Fuel Company) which expire in October 2018. In addition, at December 31, 2013 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2013, Consolidated SCE&G had no outstanding borrowings under its $1.4 billion facilities, had approximately $251 million in commercial paper borrowings outstanding, was obligated under $0.3 million in LOC-supported letters of credit, and had approximately $92 million in cash and temporary investments. Consolidated SCE&G regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance
on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2013 were approximately $369 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2013, Consolidated SCE&G’s long-term debt portfolio has a weighted average maturity of approximately 20 years and bears an average cost of 5.66%. Substantially all of Consolidated SCE&G's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, Consolidated SCE&G rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

SCE&G’s Restated Articles of Incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock, all of which is beneficially owned by SCANA.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013, approximately $63.1 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12

consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Financing Activities

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.625% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027.

In November 2012, SCE&G repaid at maturity $4.4 million of 4.2% tax-exempt industrial revenue bonds, and repaid prior to maturity $29.2 million of 5.45% tax-exempt industrial revenue bonds due November 1, 2032.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042 (issued at a premium with a yield of 3.86%), which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds which were issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

During 2013 there were net cash inflows related to financing activities of $49 million primarily due to the issuance of long-term debt and contributions from parent, partially offset by repayment of short- and long-term debt and payment of dividends.

Investing Activities

SCE&G paid approximately $6 million, net, through the third quarter of 2013 to settle interest rate derivative contracts upon the issuance of long-term debt for contracts that had been designated as hedges.

In addition, during the fourth quarter of 2013, SCE&G received approximately $120 million upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt. Pursuant to SCPSC accounting orders, $50.1 million of such gains were recognized within other income, with such gain recognition being fully offset by downward adjustments to revenues reflected within electric margin.

In February 2014, Consolidated SCE&G’s Boards of Directors declared dividends on common stock of $64.3 million, payable on April 1, 2014.

For additional information, see Note 4 to the consolidated financial statements.

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act included 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 and 50% bonus depreciation for property placed in service for 2012. The American Taxpayer Relief Act of 2012 extended the 50% bonus depreciation for property placed in service in 2013. These incentives, along with certain other deductions, have had a positive impact on the cash flows of Consolidated SCE&G.

ENVIRONMENTAL MATTERS

Consolidated SCE&G’s operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. Compliance with these environmental requirements involves significant capital and operating costs, which Consolidated SCE&G expects to recover through existing ratemaking provisions.

For the three years ended December 31, 2013, Consolidated SCE&G's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $46.1 million. In addition, Consolidated SCE&G made expenditures to operate and maintain environmental control equipment at its fossil plants of $9.2 million in 2013, $10.2 million in 2012 and $7.9 million during 2011, which are included in “Other operation and maintenance” expense, and made expenditures to handle waste ash of $3.2 million in 2013, $7.9 million in 2012 and $8.7 million in 2011, which are included in “Fuel used in electric generation.” In addition, included within “Other operation and maintenance” expense is an annual amortization of $1.4 million in each of 2013, 2012 and 2011 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for Consolidated SCE&G are $9.5 million for 2014 and $82.5 million for the four-year period 2015-2018. These expenditures are included in Consolidated SCE&G Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

At the state level, no significant environmental legislation that would affect Consolidated SCE&G’s operations advanced during 2013. Consolidated SCE&G cannot predict whether such legislation will be introduced or enacted in 2014, or if new regulations or changes to existing regulations at the state level will be implemented in the coming year. Several regulatory initiatives at the federal level did advance in 2013 and more are expected to advance in 2014 as described below.

Air Quality

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, Consolidated SCE&G is subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. Consolidated SCE&G cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact Consolidated SCE&G, and the following discussion should not be considered all-inclusive.

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. Consolidated SCE&G also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on Consolidated SCE&G, if any. Consolidated SCE&G expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed Consolidated SCE&G to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. Consolidated SCE&G will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and Consolidated SCE&G's evaluation of the rule is ongoing. SCE&G's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in Consolidated SCE&G's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though Consolidated SCE&G cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

Physical effects associated with climate changes could include the impact of possible changes in weather patterns, such as storm frequency and intensity, and the resultant potential damage to Consolidated SCE&G’s electric system, as well as impacts on employees and customers and on its supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. In addition, SCE&G has collected funds from customers for its storm damage reserve (see Note 2 to the consolidated financial statements). As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations in advance of such storms, all in order to allow Consolidated SCE&G to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Water Quality

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014. Consolidated SCE&G is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of SCE&G and GENCO. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

Hazardous and Solid Wastes

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While Consolidated SCE&G cannot predict how extensive the regulations will be, Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

The final CCR rule may require the closure of ash ponds. SCE&G has three generating facilities that have employed ash storage ponds, and all of these ponds have either been closed after all ash was removed or are part of an ash pond closure project that includes complete removal of the ash prior to closure. The electric generating facilities which continue to be coal-fired have dry ash handling, and the ash ponds undergoing closure have a detailed dam safety inspection conducted at least quarterly.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2012, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the state of South Carolina has a similar law. Consolidated SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean up. In addition, regulators from the EPA and other federal or state agencies periodically notify Consolidated SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized with recovery provided through rates. Consolidated SCE&G has assessed the following matters:

Electric Operations

SCE&G maintains an environmental assessment program to identify and evaluate its current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. At December 31, 2013, such regulatory assets totaled approximately $1.2 million. Other environmental costs are recorded to expense as incurred.

Gas Distribution

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC. SCE&G anticipates that major remediation activities at these sites will continue until 2017 and will cost an additional $21.2 million. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

REGULATORY MATTERS

SCE&G, GENCO and Fuel Company are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCE&G, GENCO and Fuel Company	The CFTC to the extent they transact swaps as defined in Dodd-Frank.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions and other matters; the PHMSA as to integrity management requirements for gas distribution pipeline systems; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety, antitrust considerations and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale for resale, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to the issuance of short-term borrowings, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of Consolidated SCE&G's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Utility Regulation

Consolidated SCE&G's regulated operations record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, Consolidated SCE&G may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of Consolidated SCE&G's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of Consolidated SCE&G's regulatory assets and liabilities, including those associated with Consolidated SCE&G's environmental program.

Consolidated SCE&G's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, Consolidated SCE&G could be required to write down its investment in those assets. Consolidated SCE&G cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect Consolidated SCE&G's results of operations in the period in which they would be recorded. As of December 31, 2013, Consolidated SCE&G's net investments in fossil/hydro and nuclear generation assets were $2.4 billion and $2.9 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, SCE&G records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2013 and 2012, accounts receivable included unbilled revenues of $111.9 million and $129.0 million, respectively, compared to total revenues of $2.8 billion for each of such years.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G’s accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact SCE&G’s financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

Asset Retirement Obligations

Consolidated SCE&G accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation in accordance with applicable accounting guidance. The obligations are recognized at present value in the period in which they are incurred and associated asset retirement costs are capitalized as a part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to Consolidated SCE&G’s utility operations, their recognition has no significant impact on results of operations. As of December 31, 2013, Consolidated SCE&G has recorded AROs of $191 million for nuclear plant decommissioning (as discussed above) and AROs of $356 million for other conditional obligations related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded in accordance with the relevant accounting guidance are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

SCE&G participates in SCANA’s noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees. SCANA recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. SCANA’s plan is adequately funded under current regulations. Accounting guidance requires the use of several assumptions, the selection of which has an impact on the resulting pension cost recorded. Among the more sensitive assumptions are those surrounding discount rates and expected returns on assets. SCANA's net pension cost of $31.7 million ($26.0 million attributable to SCE&G) recorded in 2013 reflects the use of a 4.10% discount rate prior to re-measurement on September 1, 2013 and a 5.07% discount rate after the re-measurement, derived using a cash flow matching technique, and an assumed 8.00% long-term rate of return on plan assets. The re-measurement occurred in connection with a plan amendment and related curtailment, which is further described below. SCANA believes that these assumptions were, and that the resulting pension cost amount was, reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2013 would have increased SCANA's pension cost by $1.2 million. Further, had the assumed long-term rate of return on assets been 7.75%, SCANA's pension cost for 2013 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

SCANA determines the fair value of a large majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, SCANA evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2013, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 7.5%, 6.3%, 8.8% and 9.7%, respectively. The 2013 expected long-term rate of return of 8.00% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. SCANA regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2014, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.4%, 6.0%, 8.3% and 9.3%, respectively. For 2014, the expected rate of return is 8.00%.

As of December 31, 2013, 2012, and 2011, approximately $5.5 million, $14.9 million and $9.0 million, respectively, of pension expense was deferred pursuant to regulatory orders. As part of a December 2012 SCPSC rate order, cumulative previously deferred pension costs related to electric operations of approximately $63 million is being amortized over approximately 30 years, and starting in January 2013 current pension expense for electric operations is being recovered through a pension cost rider. Similarly, in connection with the October 2013 RSA order, previously deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates.

In the third quarter of 2013, the pension plan was amended such that pension benefits will no longer be offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, SCANA recorded a curtailment charge due to the accelerated amortization of prior service cost. Approximately $5.3 million of the curtailment charge was applicable to regulated operations and was deferred within regulatory assets. SCE&G is recovering such deferred amounts through existing regulatory orders.

The closure of the plan to entrants after December 31, 2013 and the cessation of benefit accruals in 2023 are expected to further lessen the significance of pension costs and the criticality of the related estimates to SCE&G's financial statements. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. SCANA accounts for the cost of postretirement medical and life insurance benefit plans in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. SCANA used a discount rate of 4.19%, derived using a cash flow matching technique, and recorded a net cost to SCE&G of $16.5 million for 2013. Had the selected discount rate been 3.94% (25 basis points lower than the discount rate referenced above), the expense for 2013 would have been $0.5 million higher. Because the plan provisions include "caps" on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

NEW NUCLEAR CONSTRUCTION MATTERS

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

It is expected that Unit 2 will be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in revised rates filings under the BLRA.

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals. For further discussion of new nuclear construction matters, see Note 9.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution of these specific claims is discussed in Note 2 to the consolidated financial statements. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide for detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units’ reactor buildings (March 2013 for the first New Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification. Under current provisions of the Internal Revenue Code and based on SCE&G's current 55% ownership and other assumptions regarding volumes of electricity to be generated by the New Units, the aggregate production tax credits for which SCE&G qualifies could exceed $1.3 billion over the eight year period following each of the New Units' in-service dates. In January 2014, SCE&G amended its application to include the additional 5% interest in the New Units that it expects to acquire. Additional production tax credits related to the 5% interest could total as much as $125 million.

OTHER MATTERS

Financial Regulatory Reform

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. Consolidated SCE&G has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. Consolidated SCE&G is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

Off-Balance Sheet Transactions

Consolidated SCE&G does not hold significant investments in unconsolidated special purpose entities. Consolidated SCE&G does not engage in off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars, none of which are considered significant.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by Consolidated SCE&G described below are held for purposes other than trading.

The tables below provide information about long-term debt issued by Consolidated SCE&G which is sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

	Expected Maturity Date							
December 31, 2013 **Millions of dollars**	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	45.2	9.2	108.6	8.2	717.9	3,086.5	3,975.6	4,356.6
Average Interest Rate (%)	4.84	4.73	1.11	4.96	5.95	6.62	6.32	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	64.9
Average Variable Interest Rate (%)	—	—	—	—	—	0.11	0.11	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	600.0	650.0	—	—	—	71.4	1,321.4	30.6
Average Pay Interest Rate (%)	3.96	4.16	—	—	—	3.29	4.02	—
Average Receive Interest Rate (%)	0.25	0.25	—	—	—	0.06	0.24	—

	Expected Maturity Date							
December 31, 2012 **Millions of dollars**	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	159.5	45.1	8.6	8.1	7.7	3,405.9	3,634.9	4,458.0
Average Interest Rate (%)	6.98	4.84	4.85	5.01	5.12	5.60	5.65	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	65.8
Average Variable Interest Rate (%)	—	—	—	—	—	0.17	0.17	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	600.0	300.0	—	—	—	71.4	971.4	(2.5)
Average Pay Interest Rate (%)	3.01	2.48	—	—	—	3.29	2.87	—
Average Receive Interest Rate (%)	0.31	0.31	—	—	—	0.13	0.29	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above tables exclude long-term debt of $3 million at December 31, 2013 and $9 million at December 31, 2012, which amounts do not have stated interest rates associated with them.

For further discussion of Consolidated SCE&G's long-term debt and interest rate derivatives, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2013	2012
Assets		
Utility Plant In Service	$ 10,378	$ 10,096
Accumulated Depreciation and Amortization	(3,499)	(3,322)
Construction Work in Progress	2,682	2,073
Plant to be Retired, Net	177	362
Nuclear Fuel, Net of Accumulated Amortization	310	166
Utility Plant, Net ($720 and $640 related to VIEs)	10,048	9,375
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	69	57
Assets held in trust, net-nuclear decommissioning	101	94
Other investments	3	3
Nonutility Property and Investments, Net	173	154
Current Assets:		
Cash and cash equivalents	92	51
Receivables, net of allowance for uncollectible accounts of $3 and $3	486	483
Receivables-affiliated companies	19	2
Inventories:		
Fuel	131	203
Materials and supplies	120	126
Emission allowances	1	1
Prepayments and other	80	143
Total Current Assets ($147 and $206 related to VIEs)	929	1,009
Deferred Debits and Other Assets:		
Pension asset	96	—
Regulatory assets	1,303	1,377
Other	151	189
Total Deferred Debits and Other Assets ($35 and $54 related to VIEs)	1,550	1,566
Total	$ 12,700	$ 12,104

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2013	2012
Capitalization and Liabilities		
Common equity	$ 4,372	$ 3,929
Noncontrolling interest	117	114
Total Equity	4,489	4,043
Long-Term Debt, net	4,007	3,557
Total Capitalization	8,496	7,600
Current Liabilities:		
Short-term borrowings	251	449
Current portion of long-term debt	48	165
Accounts payable	241	281
Affiliated payables	117	124
Customer deposits and customer prepayments	56	51
Taxes accrued	223	151
Interest accrued	64	63
Dividends declared	62	46
Derivative financial instruments	1	66
Other	71	50
Total Current Liabilities	1,134	1,446
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,509	1,479
Deferred investment tax credits	32	36
Asset retirement obligations	547	535
Postretirement benefits	173	254
Regulatory liabilities	732	665
Other	77	89
Total Deferred Credits and Other Liabilities	3,070	3,058
Commitments and Contingencies (Note 10)	—	—
Total	$ 12,700	$ 12,104

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, (Millions of dollars)	2013	2012	2011
Operating Revenues:			
Electric	$ 2,431	$ 2,453	$ 2,432
Gas	414	356	387
Total Operating Revenues	2,845	2,809	2,819
Operating Expenses:			
Fuel used in electric generation	751	844	922
Purchased power	43	28	19
Gas purchased for resale	244	197	240
Other operation and maintenance	557	542	515
Depreciation and amortization	313	293	286
Other taxes	200	188	183
Total Operating Expenses	2,108	2,092	2,165
Operating Income	737	717	654
Other Income (Expense):			
Other income	53	—	5
Other expenses	(18)	(18)	(12)
Interest charges, net of allowance for borrowed funds used during construction of $13, $11 and $7	(217)	(211)	(204)
Allowance for equity funds used during construction	25	21	13
Total Other Expense	(157)	(208)	(198)
Income Before Income Tax Expense	580	509	456
Income Tax Expense	189	157	140
Net Income	391	352	316
Less Net Income Attributable to Noncontrolling Interest	11	11	10
Earnings Available to Common Shareholder	$ 380	$ 341	$ 306

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (Millions of dollars)	2013	2012	2011
Net Income	$ 391	$ 352	$ 316
Other Comprehensive Income (Loss), net of tax:			
Deferred costs of employee benefit plans, net of tax $-, $- and $-	1	(1)	(1)
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax $-, $- and $-	—	—	—
Other Comprehensive Income (Loss)	1	(1)	(1)
Total Comprehensive Income	392	351	315
Less comprehensive income attributable to noncontrolling interest	(11)	(11)	(10)
Comprehensive income available to common shareholder	$ 381	$ 340	$ 305

See Notes to Consolidated Financial Statement

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2013	2012	2011
Cash Flows From Operating Activities:			
Net income	$ 391	$ 352	$ 316
Adjustments to reconcile net income to net cash provided from operating activities:			
Losses from equity method investments	3	4	2
Deferred income taxes, net	29	116	138
Depreciation and amortization	315	294	288
Amortization of nuclear fuel	57	44	40
Allowance for equity funds used during construction	(25)	(21)	(13)
Carrying cost recovery	(3)	—	—
Changes in certain assets and liabilities:			
Receivables	(36)	35	(31)
Inventories	35	(60)	(25)
Prepayments	(17)	(64)	82
Regulatory assets	83	(158)	(165)
Other regulatory liabilities	54	64	(12)
Accounts payable	5	27	(48)
Taxes accrued	72	1	13
Interest accrued	1	9	4
Pension and other postretirement benefits	(186)	69	70
Other assets	52	(84)	27
Other liabilities	22	46	(31)
Net Cash Provided From Operating Activities	852	674	655
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,003)	(978)	(786)
Proceeds from investments and sales of assets (including derivative collateral posted)	144	275	11
Purchase of investments (including derivative collateral posted)	(116)	(268)	(57)
Payments upon interest rate derivative contract settlement	(49)	—	(31)
Proceeds from interest rate derivative contract settlement	163	14	—
Net Cash Used For Investing Activities	(861)	(957)	(863)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	451	513	379
Contribution from parent	311	128	107
Repayment of long-term debt	(251)	(49)	(206)
Dividends	(241)	(202)	(205)
Short-term borrowings-affiliate, net	(22)	(9)	(13)
Short-term borrowings, net	(198)	(63)	131
Net Cash Provided From Financing Activities	50	318	193
Net Increase (Decrease) in Cash and Cash Equivalents	41	35	(15)
Cash and Cash Equivalents, January 1	51	16	31
Cash and Cash Equivalents, December 31	$ 92	$ 51	$ 16
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $13, $11 and $7)	$ 200	$ 186	$ 181
—Income taxes	92	105	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	100	116	75
Capital lease	4	8	6
Nuclear fuel purchase	98	—	—

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Common Stock		Retained	Accumulated Other Comprehensive	Noncontrolling	Total
Millions	Shares	Amount	Earnings	Income (Loss)	Interest	Equity
Balance at January 1, 2011	40	$ 1,934	$ 1,505	$ (2)	$ 104	$ 3,541
Earnings available for common shareholder			306		10	316
Deferred cost of employee benefit plans, net of tax $-				(1)		(1)
Total Comprehensive Income (Loss)			306	(1)	10	315
Capital contributions from parent		107				107
Cash dividends declared			(184)		(6)	(190)
Balance at December 31, 2011	40	2,041	1,627	(3)	108	3,773
Earnings Available for Common Shareholder			341		11	352
Deferred Cost of Employee Benefit Plans, net of tax $-				(1)		(1)
Total Comprehensive Income (Loss)			341	(1)	11	351
Capital contributions from parent		126			2	128
Cash dividends declared			(202)		(7)	(209)
Balance at December 31, 2012	40	2,167	1,766	(4)	114	4,043
Earnings Available for Common Shareholder			380		11	391
Deferred Cost of Employee Benefit Plans, net of tax $-				1		1
Total Comprehensive Income			380	1	11	392
Capital contributions from parent		312			(1)	311
Cash dividends declared			(250)		(7)	(257)
Balance at December 31, 2013	40	$ 2,479	$ 1,896	$ (3)	$ 117	$ 4,489

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs), and accordingly, the accompanying consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. Accordingly, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's consolidated financial statements. Intercompany balances and transactions between SCE&G, Fuel Company and GENCO have been eliminated in consolidation.

GENCO owns a coal-fired electric generating station with a 605 megawatt net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $476 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated substantially at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. Consolidated SCE&G calculated AFC using average composite rates of 6.9% for 2013, 6.3% for 2012 and 4.6% for 2011. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Consolidated SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were 2.94% in 2013, 2.91% in 2012 and 2.90% in 2011.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2013		2012	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.1 billion	—	$ 1.1 billion	—
Accumulated depreciation	$ 566.9 million	—	$ 557.0 million	—
Construction work in progress	$ 127.1 million	$ 2.3 billion	$ 113.6 million	$ 1.8 billion

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC. For a discussion of when the New Units are expected to be placed in service, and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $75.6 million at December 31, 2013 and $92.9 million at December 31, 2012.

Plant to be Retired

As previously disclosed, in 2012 SCE&G identified a total of six coal-fired units that it intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (summer 2012) of 730 MW. As of December 31, 2013, three of these units had been retired and their net carrying value is recorded in regulatory assets (see Note 2). The net carrying value of the remaining units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these remaining units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the balance sheet (see Note 2). Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2013 and 2012, SCE&G incurred $18.1 million and $11.1 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. SCE&G accrued $1.2 million per month from January 2010 through December 2012 for its portion of the outages in the spring of 2011 and the fall of 2012. Total costs for the 2011 outage were $34.1 million, of which SCE&G was responsible for $22.7 million. Total costs for the 2012 outage were $32.3 million, of which SCE&G was responsible for $21.5 million. In connection with the SCPSC's December 2012 approval of SCE&G's retail electric rates (see Note 2), effective January 1, 2013, SCE&G began to accrue $1.4 million per month for its portion of the nuclear refueling outages that are scheduled to occur through the spring of 2020.

Nuclear Decommissioning

SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars, pursuant an updated decommissioning cost study performed in 2012. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2013, 2012 and 2011) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Consolidated SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Accounts Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Inventory

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas and fuel oil. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC. Emission allowances are included in inventory at average cost. Emission allowances are expensed at weighted average cost as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA. Under a joint consolidated income tax allocation agreement, each SCANA subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or revenues would be recognized by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

Consolidated SCE&G records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are recorded to expense as incurred.

Income Statement Presentation

In its consolidated statements of income, Consolidated SCE&G presents the revenues and expenses of its regulated activities (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

Consolidated SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $111.9 million at December 31, 2013 and $129.0 million at December 31, 2012.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

Customers subject to the PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented an eWNA on a pilot basis for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC. See Note 2.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

2. RATE AND OTHER REGULATORY MATTERS

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G. In April 2012, the SCPSC approved SCE&G's request to decrease the total fuel cost component of its retail electric rates, and approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to recover an amount equal to its actual under-collected balance of base fuel and variable environmental costs as of April 30, 2012, or $80.6 million, over a twelve month period beginning with the first billing cycle of May 2012.

This April 2012 order was superseded, in part, by a December 2012 rate order in which the SCPSC authorized SCE&G to reduce the base fuel cost component of its retail electric rates and, in doing so, stated that SCE&G may not adjust its base fuel cost component prior to the last billing cycle of April 2014 except where necessary due to extraordinary unforeseen economic or financial conditions. In February 2013, in connection with its annual review of base rates for fuel costs, SCE&G requested authorization to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. Consistent with the December 2012 rate order, SCE&G did not request any adjustment to its base fuel cost component. In March 2013, SCE&G, ORS and the SCEUC entered into a settlement agreement accepting the proposed lower environmental fuel cost component effective with the first billing cycle of May 2013, and providing for the accrual of certain debt-related carrying costs on a portion of the under-collected balance of fuel costs. The SCPSC issued an order dated April 30, 2013, adopting and approving the settlement agreement and approving SCE&G's total fuel cost component. A public hearing for the annual review of base rates for fuel costs has been scheduled for April 3, 2014.

Pursuant to a November 2013 SCPSC accounting order, Consolidated SCE&G's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G's weighted average long-term borrowing rate, and during 2013, $2.9 million of such carrying costs were accrued within other income. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates (as discussed above), a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. In February 2013, the SCPSC denied the SCEUC's petition for rehearing and the denial was not appealed.

The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills and had been in use since August 2010. In connection with the December 2012 order, SCE&G agreed to perform a study of alternative structures for eWNA. On November 1, 2013, the ORS filed a report with the SCPSC recommending that the eWNA be terminated with the last billing cycle for December 2013. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition.

In connection with the above termination of the eWNA program effective December 31, 2013, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. Pursuant to the SCPSC accounting order granting the above relief and terminating the eWNA, such revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. One of these units was retired in 2012, and two others were retired in the fourth quarter of 2013. The net carrying value of these retired units is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

In a July 2010 order, the SCPSC provided for a $48.7 million credit to SCE&G's customers over two years to be offset by accelerated recognition of previously deferred state income tax credits. These tax credits were fully amortized in 2012.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and lost net margin revenue associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC has approved the following rate changes pursuant to annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million
2011	First billing cycle of June	$7.0 million

Other activity related to SCE&G's DSM Programs is as follows:

- In May 2013 the SCPSC ordered the deferral of one-half of the net lost revenues and provided for their recovery over a 12-month period beginning with the first billing cycle in May 2014.
- In November 2013 the SCPSC approved SCE&G's continued use of DSM programs for another six years, including approval of the rate rider mechanism and a revised portfolio of DSM programs.
- In January 2014 SCE&G submitted its annual DSM Programs filing to the SCPSC, which included, among other things, a request to (1) recover one-half of the balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2014 and to recover the remaining balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2015, (2) utilize approximately $17.8 million of the gains from the recent settlement of certain interest rate derivative instruments to offset a portion of the net lost revenues component of SCE&G's DSM Programs rider, and (3) apply $5 million of its storm damage reserve and a portion of the gains from the recent settlement of certain interest rate derivative instruments, currently estimated to be $5.5 million, to the remaining balance of deferred net lost revenue as of April 30, 2014, deferred within regulatory assets resulting from the May 2013 order previously described.

Electric - BLRA

In May 2011, the SCPSC approved an updated capital cost schedule sought by SCE&G that, among other matters, incorporated then-identifiable additional capital costs of $173.9 million (SCE&G's portion in 2007 dollars).

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals. For further discussion of new nuclear construction matters, see Note 9.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved the following rate changes under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2013	2.90%	$ 67.2 million
2012	2.30%	$ 52.1 million
2011	2.40%	$ 52.8 million

Gas

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2013	No change	
2012	2.10% Increase	$ 7.5 million
2011	2.10% Increase	$ 8.6 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2013 and 2012 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each review period were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, Consolidated SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Other than unrecovered plant, substantially all of our regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2013**	**2012**
Regulatory Assets:		
Accumulated deferred income taxes	$ 256	$ 248
Under-collections-electric fuel adjustment clause	18	66
Environmental remediation costs	37	39
AROs and related funding	350	304
Franchise agreements	31	36
Deferred employee benefit plan costs	215	405
Planned major maintenance	—	6
Deferred losses on interest rate derivatives	124	151
Deferred pollution control costs	37	38
Unrecovered Plant	145	20
DSM Programs	51	27
Other	39	37
Total Regulatory Assets	$ 1,303	$ 1,377

Regulatory Liabilities:		
Accumulated deferred income taxes	$ 19	$ 21
Asset removal costs	495	507
Storm damage reserve	27	27
Deferred gains on interest rate derivatives	181	110
Planned major maintenance	10	—
Total Regulatory Liabilities	$ 732	$ 665

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recovered over periods of up to approximately 26 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on a SCPSC order, SCE&G began amortizing these amounts through cost of service rates in February 2003 over approximately 20 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In connection with the December 2012 rate order, approximately $63 million of deferred pension costs for electric operations are being recovered through utility rates over approximately 30 years. In connection with the October 2013 RSA order, approximately $14 million of deferred pension costs for gas operations are being recovered through utility rates over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil-fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects $18.4 million annually for such equipment maintenance. Through December 31, 2012, nuclear refueling charges were accrued during each 18-month refueling outage cycle as a component of cost of service. In connection with the December 2012 rate order, effective January 1, 2013, SCE&G collects and accrues $16.8 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt, up to approximately 30 years. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the installation of scrubbers at Wateree and Williams Stations pursuant to specific regulatory orders. Such costs are being recovered through utility rates over periods up to 30 years.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives, or up to approximately 14 years. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represents deferred costs and certain unrecovered lost revenue associated with SCE&G’s Demand Side Management programs. Deferred costs are currently being recovered over 5 years through a SCPSC approved rider. Unrecovered lost revenue is to be recovered over periods not to exceed 24 months from date of deferral. See Rate Matters - Electric Base Rates above for details regarding a 2014 filing with the SCPSC regarding recovery of these deferred costs and unrecovered lost revenue.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the non-legal obligation to remove assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

The balance for accumulated other comprehensive income (loss), net of tax, was as follows:

Millions of Dollars	Deferred Employee Benefit Plans
Accumulated Other Comprehensive Loss as of January 1, 2012	$ (3)
Other comprehensive loss	(1)
Accumulated Other Comprehensive Loss as of December 31, 2012	(4)
Other comprehensive income	1
Accumulated Other Comprehensive Loss as of December 31, 2013	$ (3)

Authorized shares of SCE&G common stock were 50 million as of December 31, 2013 and 2012. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2013 and 2012.

SCE&G’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013 and 2012, approximately $63.1 million and $61.0 million of retained earnings, respectively, were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average interest rates and maturities at December 31 is as follows:

Dollars in millions	Maturity	2013 Balance	2013 Rate	2012 Balance	2012 Rate
First Mortgage Bonds (secured)	2018 - 2042	$ 3,540	5.60%	$ 3,290	5.66%
GENCO Notes (secured)	2018 - 2024	233	5.89%	240	5.87%
Industrial and Pollution Control Bonds (a)	2014 - 2038	158	3.83%	161	4.32%
Nuclear Fuel Financing	2016	100	0.78%	—	—
Other	2014 - 2027	16	2.26%	21	1.62%
Total debt		4,047		3,712	
Current maturities of long-term debt		(48)		(165)	
Unamortized premium		8		10	
Total long-term debt, net		$ 4,007		$ 3,557	

(a) Includes variable rate debt of $67.8 million at December 31, 2013 (rate of 0.11%) and 2012 (rate of 0.17%), which are hedged by fixed swaps.

The annual amounts of long-term debt maturities for the years 2014 through 2018 are summarized as follows:

Year	Millions of dollars
2014	$ 48
2015	9
2016	109
2017	8
2018	718

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.63% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027. The borrowings refinanced by these 2013 issuances are classified within Long-term Debt, Net in the consolidated balance sheet.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042, which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

Substantially all of SCE&G’s and GENCO’s electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12

consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Lines of Credit and Short-Term Borrowings

At December 31, 2013 and 2012, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC advances, commercial paper, and LOC-supported letter of credit obligations:

Millions of dollars		2013		2012
Lines of credit:				
Total committed long-term	$	1,400	$	1,400
LOC advances		—		—
Weighted average interest rate		—		—
Outstanding commercial paper (270 or fewer days)	$	251	$	449
Weighted average interest rate		0.27%		0.42%
Letters of credit supported by an LOC	$	0.3	$	0.3
Available	$	1,149	$	951

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company). In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In October 2013, the term of each of these credit agreements was extended by one year, such that the five-year agreements will expire in October 2018, and the three-year agreement expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N. A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1,400 million credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9% and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. Consolidated SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. These letters of credit expire, subject to renewal, in the fourth quarter of 2014.

Consolidated SCE&G pays fees to the banks as compensation for maintaining committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions was not significant for any period presented. At December 31, 2013 and 2012, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $27.3 million and $49.4 million, respectively, which are included within affiliated payables on the consolidated balance sheet.

5. INCOME TAXES

Components of income tax expense for 2013, 2012, and 2011 are as follows:

Millions of dollars	2013	2012	2011
Current taxes:			
Federal	$ 146	$ 91	$ 52
State	13	8	12
Total current taxes	159	99	64
Deferred taxes, net:			
Federal	25	62	98
State	9	12	6
Total deferred taxes	34	74	104
Investment tax credits:			
Amortization of amounts deferred—state	(1)	(13)	(25)
Amortization of amounts deferred—federal	(3)	(3)	(3)
Total investment tax credits	(4)	(16)	(28)
Total income tax expense	$ 189	$ 157	$ 140

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2013	2012	2011
Net income	$ 380	$ 341	$ 306
Income tax expense	189	157	140
Noncontrolling interest	11	11	10
Total pre-tax income	$ 580	$ 509	$ 456
Income taxes on above at statutory federal income tax rate	$ 203	$ 178	$ 159
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	18	17	12
State investment tax credits (less federal income tax effect)	(5)	(13)	(16)
Allowance for equity funds used during construction	(9)	(7)	(5)
Amortization of federal investment tax credits	(3)	(3)	(3)
Section 45 tax credits	(5)	(5)	(2)
Domestic production activities deduction	(11)	(9)	(6)
Other differences, net	1	(1)	1
Total income tax expense	$ 189	$ 157	$ 140

The tax effects of significant temporary differences comprising Consolidated SCE&G's net deferred tax liability at December 31, 2013 and 2012 are as follows:

Millions of dollars	2013	2012
Deferred tax assets:		
Nondeductible accruals	$ 17	$ 73
Asset retirement obligation, including nuclear decommissioning	209	204
Unamortized investment tax credits	19	21
Unbilled revenue	—	14
Regulatory liability, net gain on interest rate derivative contracts settlement	27	—
Other	11	13
Total deferred tax assets	283	325
Deferred tax liabilities:		
Property, plant and equipment	$ 1,494	$ 1,461
Regulatory asset-asset retirement obligation	114	107
Deferred employee benefit plan costs	54	127
Deferred fuel costs	26	49
Regulatory asset, unrecovered plant	55	7
Other	62	53
Total deferred tax liabilities	1,805	1,804
Net deferred tax liability	$ 1,522	$ 1,479

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA and files various applicable state and local income tax returns. The IRS has completed examinations of SCANA's federal returns through 2004, and SCANA's federal returns through 2007 are closed for additional assessment. With few exceptions, Consolidated SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2009.

Changes to Unrecognized Tax Benefits

Millions of dollars	2013	2012	2011
Unrecognized tax benefits, January 1	—	$ 38	$ 36
Gross increases-uncertain tax positions in prior period	—	—	5
Gross decreases-uncertain tax positions in prior period	—	(38)	(8)
Gross increases-current period uncertain tax positions	$ 3	—	5
Settlements	—	—	—
Lapse of statute of limitations	—	—	—
Unrecognized tax benefits, December 31	$ 3	$ —	$ 38

In connection with the change in method of tax accounting for certain repair costs in prior years, the Company had previously recorded an unrecognized tax benefit. During the first quarter of 2012, the publication of new administrative guidance from the IRS allowed Consolidated SCE&G to recognize this benefit. Since this change was primarily a temporary difference, the recognition of this benefit did not have a significant effect on the Consolidated SCE&G's effective tax rate.

During 2013, Consolidated SCE&G amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, Consolidated SCE&G recorded an unrecognized tax benefit of $3 million. If recognized, this tax benefit would affect Consolidated SCE&G's effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $5 million within the next 12 months. No other material changes in the status of the Consolidated SCE&G's tax positions have occurred through December 31, 2013.

Consolidated SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit in 2012, during 2012 Consolidated SCE&G reversed $2 million of interest expense which had been accrued during 2011. Consolidated SCE&G has not recorded interest expense or penalties associated with the 2013 uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated SCE&G recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. Consolidated SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by Consolidated SCE&G. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including Consolidated SCE&G. The Risk Management Committee, which is comprised of certain officers, including Consolidated SCE&G's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to the Audit Committee's attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Consolidated SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, Consolidated SCE&G may use treasury rate lock or forward starting swap agreements. Pursuant to regulatory orders issued in 2013, interest rate derivatives entered into by SCE&G after October 2013 are no longer designated as cash flow hedges, and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Upon settlement, losses on swaps will be amortized over the lives of related debt issuances, and gains may be applied to under-collected fuel, be amortized to interest expense or applied as otherwise directed by the SCPSC. As discussed in Note 2, in these orders, the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. Prior to this regulatory authorization, such interest rate derivatives were designated as cash flow hedges, and only the effective portions of changes in fair value and payments made or received upon termination of such agreements were recorded in regulatory assets or regulatory liabilities. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions were recognized in income.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

Consolidated SCE&G was a party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $36.4 million and $971.4 million at December 31, 2013 and 2012, respectively. Consolidated SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.3 billion and $0.0 million at December 31, 2013 and 2012, respectively.

The fair value of interest rate derivatives was reflected in the consolidated balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
Millions of dollars	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of December 31, 2013				
Derivatives designated as hedging instruments				
Interest rate contracts			Other current liabilities	$ 1
Total				$ 1
Derivatives not designated as hedging instruments				
Interest rate contracts	Prepayments and other	$ 13	Other current liabilities	$ 1
	Other deferred debits and other assets	19		
Total		$ 32		$ 1
As of December 31, 2012				
Derivatives designated as hedging instruments				
Interest rate contracts	Prepayments and other	$ 42	Other current liabilities	$ 66
	Other deferred debits and other assets	31	Other deferred credits and other liabilities	9
Total		$ 73		$ 75

The effect of derivative instruments on the consolidated statement of income is as follows:

Derivatives in Cash Flow Hedging Relationships	Gain or (Loss) Deferred in Regulatory Accounts	Loss Reclassified from Deferred Accounts into Income (Effective Portion)	
Millions of dollars	(Effective Portion)	Location	Amount
Year Ended December 31, 2013			
Interest rate contracts	$ 106	Interest expense	$ (3)
Year Ended December 31, 2012			
Interest rate contracts	$ 84	Interest expense	$ (3)
Year Ended December 31, 2011			
Interest rate contracts	$ (76)	Interest expense	$ (3)

Hedge Ineffectiveness

Other losses recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in 2013 and 2012 and were $(1.1) million, net of tax, in 2011.

Derivatives Not Designated as Hedging Instruments	Loss Recognized in Income	Year Ended December 31,		
Millions of dollars	Location	2013	2012	2011
Commodity contracts	Gas purchased for resale	—	$ (1)	$ (2)

Millions of dollars	Gain Deferred in Regulatory Accounts		Gain Reclassified from Deferred Accounts into Income: Location	Amount	
Year Ended December 31, 2013					
Interest rate contracts	$	39	Other income	$	50
Year Ended December 31, 2012					
Interest rate contracts		—			—
Year Ended December 31, 2011					
Interest rate contracts		—			—

The gains reclassified to other income of $50 million offset revenue reductions as previously described herein and in Note 2.

Credit Risk Considerations

Consolidated SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, Consolidated SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. Consolidated SCE&G uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with Consolidated SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of Consolidated SCE&G’s derivative instruments contain contingent provisions that require Consolidated SCE&G to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2013 and 2012, Consolidated SCE&G had posted $1.5 million and $35.2 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Prepayments and other on the consolidated balance sheets. Collateral related to the noncurrent positions are recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and 2012, Consolidated SCE&G would have been required to post an additional $0.0 million and $22.7 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2013 and 2012, are $1.0 million and $57.9 million, respectively.

In addition, as of December 31, 2013 and December 31, 2012, Consolidated SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and December 31, 2012, Consolidated SCE&G could request $31.7 million and $32.1 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2013 and December 31, 2012 is $31.7 million and $32.1 million, respectively.

Information related to Consolidated SCE&G's offsetting derivative assets follows:

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2013						
Interest rate	$ 32	—	$ 32	$ (1)	—	$ 31
Balance sheet location	Prepayments and other		$ 13			
	Other deferred debits and other assets		19			
	Total		$ 32			
As of December 31, 2012						
Interest rate	$ 73	—	$ 73	$ (17)	—	$ 56
Balance sheet location	Prepayments and other		$ 42			
	Other deferred debits and other assets		31			
	Total		$ 73			

Information related to Consolidated SCE&G's offsetting derivative liabilities follows:

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2013						
Interest rate	$ 2	—	$ 2	$ (1)	$ 1	$ —
Balance sheet location	Other current liabilities		$ 2			
	Total		$ 2			
As of December 31, 2012						
Interest rate	$ 75	—	$ 75	$ (17)	$ 35	$ 23
Balance sheet location	Other current liabilities		$ 66			
	Other deferred credits and other liabilities		9			
	Total		$ 75			

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Consolidated SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value Level 2 measurements were as follows:

	As of December 31, 2013	As of December 31, 2012
Millions of dollars	Level 2	Level 2
Assets-Interest rate contracts	$ 32	$ 73
Liabilities-Interest rate contracts	2	75

There were no Level 1 or Level 3 fair value measurements for either period presented and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2013 and December 31, 2012 were as follows:

	As of December 31, 2013		As of December 31, 2012	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$ 4,054.9	$ 4,433.0	$ 3,722.0	$ 4,543.1

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Carrying values reflect the fair values of interest rate swaps designated as fair value hedges, based on discounted cash flow models with independently sourced market data. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees hired before January 1, 2014. In the third quarter of 2013, SCANA amended its pension plan such that benefits are no longer offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all employees hired from January 1, 2000 through December 31, 2013. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost. Employees hired after December 31, 2010 are responsible for the full costs of retiree medical benefits elected by them. SCANA provides life insurance benefits to retirees at no charge, except that employees hired after December 31, 2010 are ineligible for retiree life insurance benefits. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects Consolidated SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumptions based on Consolidated SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2013**	**2012**	**2013**	**2012**
Benefit obligation, January 1	$ 788.4	$ 705.0	$ 206.0	$ 178.4
Service cost	17.6	15.7	4.6	3.7
Interest cost	32.6	36.4	8.7	9.4
Plan participants’ contributions	—	—	2.0	2.3
Actuarial (gain) loss	(70.7)	80.3	(27.3)	26.2
Benefits paid	(50.6)	(49.0)	(9.3)	(10.8)
Curtailment	(21.6)	—	—	—
Amounts funded to parent	—	—	(3.0)	(3.2)
Benefit obligation, December 31	$ 695.7	$ 788.4	$ 181.7	$ 206.0

The accumulated benefit obligation for pension benefits was $673.2 million at the end of 2013 and $740.2 million at the end of 2012. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	**2012**	**2013**	**2012**
Annual discount rate used to determine benefit obligation	5.03%	4.10%	5.19%	4.19%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.75%	3.75%	3.75%

A 7.4% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation at December 31, 2013 by $1.0 million and at December 31, 2012 by $1.3 million. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation at December 31, 2013 by $0.9 million and 2012 by $1.2 million.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	**2013**	**2012**	**2013**	**2012**
Fair value of plan assets	$ 792.1	$ 732.0	—	—
Benefit obligation	695.7	788.4	$ 181.7	$ 206.0
Funded status	$ 96.4	$ (56.4)	$ (181.7)	$ (206.0)

Amounts recognized on the consolidated balance sheets consist of:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Current liability	—	—	$ (7.8)	$ (8.5)
Noncurrent asset	$ 96.4	—	—	—
Noncurrent liability	—	$ (56.4)	(173.9)	(197.5)

Amounts recognized in accumulated other comprehensive loss (a component of common equity) as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$ 1.8	$ 2.7	$ 0.6	$ 1.1
Prior service cost	0.2	0.2	—	—
Total	$ 2.0	$ 2.9	$ 0.6	$ 1.1

Amounts recognized in regulatory assets as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$ 107.7	$ 257.5	$ 20.1	$ 46.7
Prior service cost	11.1	23.3	0.7	1.2
Transition obligation	—	—	—	0.1
Total	$ 118.8	$ 280.8	$ 20.8	$ 48.0

In connection with the joint ownership of Summer Station, as of December 31, 2013 and 2012, SCE&G recorded within deferred debits $14.1 million and $26.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2013 and 2012, SCE&G also recorded within deferred debits $12.6 million and $14.7 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2013	2012
Fair value of plan assets, January 1	$ 732.0	$ 695.3
Actual return on plan assets	110.7	85.7
Benefits paid	(50.6)	(49.0)
Fair value of plan assets, December 31	$ 792.1	$ 732.0

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan is closed to new entrants effective January 1, 2014, and benefit accruals will cease effective January 1, 2024. In addition, during 2013, SCANA adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs in connection with the amendments to the plan.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2013 and 2012 and the target allocation for 2014 are as follows:

	Percentage of Plan Assets		
	Target Allocation	At December 31,	
Asset Category	2014	2013	2012
Equity Securities	58%	59%	66%
Fixed Income	33%	32%	25%
Hedge Funds	9%	9%	9%

For 2014, the expected long-term rate of return on assets will be 8.00%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes an asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment policy adopted for 2014.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2013 and 2012, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using							
Millions of dollars	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	December 31, 2013				*December 31, 2012*			
Common stock	$ 302	$ 302			$ 292	$ 292		
Preferred stock	1	1			1	1		
Mutual funds	278	18	$ 260		226	12	$ 214	
Short-term investment vehicles	18		18		18		18	
US Treasury securities	30		30		38		38	
Corporate debt securities	48		48		52		52	
Loans secured by mortgages	11		11		10		10	
Municipals	3		3		4		4	
Limited partnerships	32	1	31		27	1	26	
Multi-strategy hedge funds	69			$ 69	64			$ 64
	$ 792	$ 322	$ 401	$ 69	$ 732	$ 306	$ 362	$ 64

There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2013 or 2012.

The pension plan values common stock, preferred stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	**2013**	**2012**
Beginning Balance	$ 64	$ 60
Unrealized gains included in changes in net assets	5	4
Purchases, issuances, and settlements	—	—
Transfers in or out of Level 3	—	—
Ending Balance	$ 69	$ 64

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from SCE&G's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2014	$ 61.5	$ 9.3
2015	61.2	10.0
2016	63.8	10.6
2017	65.8	11.1
2018	66.1	11.6
2019 - 2023	338.4	65.1

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

Millions of dollars	Pension Benefits 2013	Pension Benefits 2012	Pension Benefits 2011	Other Postretirement Benefits 2013	Other Postretirement Benefits 2012	Other Postretirement Benefits 2011
Service cost	$ 17.6	$ 15.7	$ 14.7	$ 4.6	$ 3.7	$ 3.4
Interest cost	32.6	36.4	37.0	8.7	9.4	9.6
Expected return on assets	(51.9)	(50.4)	(54.2)	n/a	n/a	n/a
Prior service cost amortization	5.0	6.0	6.0	0.6	0.7	0.8
Amortization of actuarial losses	14.3	15.6	10.4	2.6	1.1	0.3
Curtailment	8.4	—	—	—	—	—
Transition obligation amortization	—	—	—	—	—	(0.1)
Net periodic benefit cost	$ 26.0	$ 23.3	$ 13.9	$ 16.5	$ 14.9	$ 14.0

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension costs related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension cost related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2).

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

Millions of dollars	Pension Benefits 2013	Pension Benefits 2012		Pension Benefits 2011	Other Postretirement Benefits 2013	Other Postretirement Benefits 2012		Other Postretirement Benefits 2011
Current year actuarial (gain) loss	$ (0.8)	$ 0.4		$ 0.7	$ (0.4)	$ 0.7	—	$ 0.1
Amortization of actuarial losses	(0.1)	(0.1)		(0.1)	(0.1)	—	—	—
Amortization of prior service cost	—	(0.1)	—	(0.1)	—	(0.1)	—	—
Prior service cost (credit)	—	—	400,000	—	—	—	—	—
Amortization of transition obligation	—	—	—	—	—	—		—
Total recognized in other comprehensive income (loss)	$ (0.9)	$ 0.2	400,000	$ 0.5	$ (0.5)	$ 0.6		$ 0.1

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

Millions of dollars	Pension Benefits 2013	Pension Benefits 2012		Pension Benefits 2011	Other Postretirement Benefits 2013	Other Postretirement Benefits 2012		Other Postretirement Benefits 2011
Current year actuarial (gain) loss	$ (137.1)	$ 37.9		$ 61.8	$ (24.4)	$ 25.7	—	$ 5.0
Amortization of actuarial losses	(12.7)	(14.0)		(9.3)	(2.2)	(1.0)	—	(0.2)
Amortization of prior service cost	(4.5)	(5.7)	—	(5.5)	(0.5)	(0.7)	—	(0.7)
Prior service cost (credit)	(7.7)	—	400,000	—	—	—	—	—
Amortization of transition obligation	—	—	—	—	(0.1)	(0.2)		(0.2)
Total recognized in regulatory assets	$ (162.0)	$ 18.2		$ 47.0	$ (27.2)	$ 23.8		$ 3.9

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	4.10%/5.07%	5.25%	5.56%	4.19%	5.35%	5.72%
Expected return on plan assets	8.00%	8.25%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.75%/3.00%	4.00%	4.00%	3.75%	4.00%	4.00%
Health care cost trend rate	n/a	n/a	n/a	7.80%	8.20%	8.00%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2017

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2014 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 3.7	$ 0.3
Prior service cost	3.1	0.3
Total	$ 6.8	$ 0.6

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

Stock Purchase Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan for 2013, 2012 and 2011 were $18.7million, $17.7 million and $17.3 million, respectively, and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the LTECP which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation costs related to share-based payment transactions are required to be recognized in the financial statements. With limited exceptions, including those liability awards discussed below, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

Liability Awards

The 2011-2013, 2012-2014, and 2013-2015 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. In each of the performance cycles, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of retirement or termination of employment prior to the end of the cycle, subject to exceptions for death, disability or change in control. The remaining 80% of the award was granted in performance shares. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in "GAAP-adjusted net earnings per share from operations" (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2011-2013 performance cycle were paid in cash at SCANA's discretion in February 2014. Cash-settled liabilities related to prior program cycles were paid totaling approximately $3.2 million in 2013, $8.7 million in 2012 and $2.5 million in 2011.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling $ 5.5 million in 2013, $9.5 million in 2012 and $4.0 million in 2011. Fair value adjustments resulted in capitalized compensation costs of $ 0.5 million in 2013, $2.1 million in 2012 and $0.2 million in 2011.

Equity Awards

No equity awards were made during any period presented, and the effects of previous such awards on Consolidated SCE&G's results of operations, cash flows and financial position were not significant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $41.6 million

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Consolidated SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC.

SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. Under the terms of the agreement SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in a revised rates filing under the BLRA.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution of these specific claims is discussed in Note 2. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that the revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled "Recommendations for Enhancing Reactor Safety in the 21st Century." This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units' reactor buildings (March 2013 for the first New Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification.

Environmental

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. Consolidated SCE&G also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on Consolidated SCE&G, if any. Consolidated SCE&G expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed below.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed Consolidated SCE&G to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. Consolidated SCE&G will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and Consolidated SCE&G's evaluation of the rule is ongoing. SCE&G's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in Consolidated SCE&G's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014. Consolidated SCE&G is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of SCE&G and GENCO. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While Consolidated SCE&G cannot predict how extensive the regulations will be, Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2013, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017, and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2017 and will cost an additional $20.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

Claims and Litigation

Consolidated SCE&G is engaged in various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on Consolidated SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

Consolidated SCE&G is obligated under various operating leases for vehicles, office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $ 13.6 million in 2013, $9.6 million in 2012 and $10.8 million in 2011. Future minimum rental payments under such leases are as follows:

	Millions of dollars	
2014	$	4
2015		3
2016		2
2017		1
2018		1
Thereafter		19
Total	$	30

Asset Retirement Obligations

Consolidated SCE&G recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to Consolidated SCE&G's regulated utility operations. As of December 31, 2013, Consolidated SCE&G has recorded AROs of approximately $191 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $356 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars		2013		2012
Beginning balance	$	535	$	450
Liabilities incurred		5		—
Liabilities settled		(4)		(5)
Accretion expense		24		23
Revisions in estimated cash flows		(13)		67
Ending Balance	$	547	$	535

11. AFFILIATED TRANSACTIONS

CGT transports natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. Such purchases totaled approximately $33.3 million in 2013, $35.9 million in 2012 and $30.8 million in 2011. SCE&G had approximately $3.3 million and $3.4 million payable to CGT for transportation services at December 31, 2013 and December 31, 2012, respectively. SCE&G had approximately $1.3 million receivable from CGT for transportation services at December 31, 2013 and an insignificant receivable amount at December 31, 2012.

SCE&G purchases natural gas and related pipeline capacity from SEMI to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $166.9 million in 2013, $125.5 million in 2012 and $187.4 million in 2011. SCE&G's payables to SEMI for such purposes were $12.5 million and $13.1 million as of December 31, 2013 and 2012, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC which is involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's receivable from this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's payable to this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's total purchases to this affiliate were $134.2 million in 2013 and $111.6 million in 2012. SCE&G's total sales to this affiliate were $133.6 million in 2013 and $111.1 million in 2012.

An affiliate processes and pays invoices for Consolidated SCE&G and is reimbursed. Consolidated SCE&G owed $49.1 million and $39.4 million to the affiliate at December 31, 2013 and 2012, respectively, for invoices paid by the affiliate on its behalf.

SCANA Services provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, and general administrative services. Costs for these services totaled $285.6 million in 2013, $305.6 million in 2012 and $302.6 million in 2011.

12. SEGMENT OF BUSINESS INFORMATION

Consolidated SCE&G's reportable segments follow the same accounting policies as those described in Note 1.

Electric Operations is primarily engaged in the generation, transmission, and distribution of electricity, and is regulated by the SCPSC and FERC. Gas Distribution is engaged in the purchase and sale, primarily at retail, of natural gas, and is regulated by the SCPSC.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2013				
External Revenue	$ 2,431	$ 414	—	$ 2,845
Operating Income	679	58	—	737
Interest Expense	19	—	$ 198	217
Depreciation and Amortization	294	26	(7)	313
Segment Assets	9,488	686	2,526	12,700
Expenditures for Assets	907	45	51	1,003
Deferred Tax Assets	10	n/a	(10)	—
2012				
External Revenue	$ 2,453	$ 356	—	$ 2,809
Operating Income	668	49	—	717
Interest Expense	21	—	$ 190	211
Depreciation and Amortization	278	25	(10)	293
Segment Assets	8,989	659	2,456	12,104
Expenditures for Assets	999	56	(77)	978
Deferred Tax Assets	9	n/a	(9)	—
2011				
External Revenue	$ 2,432	$ 387	—	$ 2,819
Operating Income	616	40	$ (2)	654
Interest Expense	23	—	181	204
Depreciation and Amortization	271	25	(10)	286
Segment Assets	8,222	622	2,193	11,037
Expenditures for Assets	806	60	(18)	848
Deferred Tax Assets	9	n/a	(1)	8

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, Consolidated SCE&G does not allocate interest charges, income tax expense, earnings available to common shareholder or assets other than utility plant to its segments. Intersegment revenue and interest income were not significant. Consolidated SCE&G's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to asset retirement obligations, and totals not allocated to other segments.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2013					
Total operating revenues	$ 728	$ 696	$ 776	$ 645	$ 2,845
Operating income	191	180	255	111	737
Net Income	92	88	139	72	391
Earnings Available to Common Shareholder	89	85	136	70	380
2012					
Total operating revenues	$ 663	$ 661	$ 777	$ 708	$ 2,809
Operating income	156	165	241	155	717
Net Income	72	78	132	70	352
Earnings Available to Common Shareholder	69	76	129	67	341

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCANA's management, including the CEO and CFO, of the effectiveness of the design and operation of SCANA's disclosure controls and procedures. For purposes of this evaluation, disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by SCANA in the reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to SCANA's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, SCANA's management, including the CEO and CFO, concluded that SCANA's disclosure controls and procedures were effective as of December 31, 2013.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCANA's management, including the CEO and CFO, of any change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2013. There has been no change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2013 that has materially affected or is reasonably likely to materially affect SCANA's internal control over financial reporting.

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and that it has assessed, as of December 31, 2013, the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA's internal control system was designed by or under the supervision of SCANA's management, including the CEO and CFO, to provide reasonable assurance to SCANA's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA's management assessed the effectiveness of SCANA's internal control over financial reporting as of December 31, 2013. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (1992)*. Based on this assessment, SCANA's management believes that, as of December 31, 2013, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on SCANA's internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2013, of the Company and our report dated February 28, 2014, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCE&G's management, including the CEO and CFO, of the effectiveness of the design and operation of SCE&G's disclosure controls and procedures. For purposes of this evaluation, disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by SCE&G in the reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to SCE&G's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, SCE&G's management, including the CEO and CFO, concluded that SCE&G's disclosure controls and procedures were effective as of December 31, 2013.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCE&G's management, including the CEO and CFO, of any change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2013. There has been no change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2013 that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and that it has assessed, as of December 31, 2013, the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G's internal control system was designed by or under the supervision of SCE&G's management, including the CEO and CFO, to provide reasonable assurance to SCE&G's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G's management assessed the effectiveness of SCE&G's internal control over financial reporting as of December 31, 2013. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (1992).* Based on this assessment, SCE&G's management believes that, as of December 31, 2013, internal control over financial reporting is effective based on those criteria.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 25. The other information required by Item 10 is incorporated herein by reference to the captions "NOMINEES FOR DIRECTORS," "CONTINUING DIRECTORS," "BOARD MEETINGS-COMMITTEES OF THE BOARD", "GOVERNANCE INFORMATION-SCANA's Code of Conduct & Ethics" and "OTHER INFORMATION-Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by Item 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Discussion and Analysis," Compensation Committee Report," "Summary Compensation Table," "2013 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2013 Fiscal Year-End," "2013 Option Exercises and Stock Vested," "Pension Benefits," "2013 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: Information required by Item 12 is incorporated herein by reference to the caption "SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

Equity securities issuable under SCANA's compensation plans at December 31, 2013 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
Long-Term Equity Compensation Plan	n/a	n/a	3,138,638
Non-Employee Director Compensation Plan	n/a	n/a	100,886
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	n/a	n/a	3,239,524

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: The information required by Item 13 is incorporated herein by reference to the caption "RELATED PARTY TRANSACTIONS" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA: The information required by Item 14 is incorporated herein by reference to "PROPOSAL 2-APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities and Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm's Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to SCE&G and its consolidated affiliates for the fiscal years ended December 31, 2013 and 2012 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2013	2012
Audit Fees (1)	$ 1,972,696	$ 1,772,129
Audit-Related Fees (2)	115,706	258,357
Total Fees	$ 2,088,402	$ 2,030,486

(1) Fees for audit services billed in 2013 and 2012 consisted of audits of annual financial statements, comfort letters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits and, in 2012, for non-statutory audit services.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under Item 8 herein.

The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under Item 8 herein.

The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts
(in millions)

Description		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2013	$ 7	$ 13	—	$ 14	$ 6
	2012	6	14	—	13	7
	2011	9	17	—	20	6
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2013	$ 6	$ 4	—	$ 4	$ 6
	2012	6	4	—	4	6
2011		5	4	—	3	6
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2013	$ 3	$ 7	—	$ 7	$ 3
	2012	3	6	—	6	3
2011		3	6	—	6	3
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2013	$ 5	$ 3	—	$ 3	$ 5
	2012	4	3	—	2	5
2011		4	2	—	2	4

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

DATE: February 28, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Controller
(Principal Accounting Officer)

Other Directors*:

J. A. Bennett	L. M. Miller
J. F. A. V. Cecil	J. W. Roquemore
D. M. Hagood	M. K. Sloan
J. W. Martin, III	H. C. Stowe
J. M. Micali	A. Trujillo

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 28, 2014

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director

DATE: February 28, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison
J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV
J. E. Swan, IV
Controller
(Principal Accounting Officer)

Other Directors*:

J. A. Bennett	J. W. Roquemore
D. M. Hagood	M. K. Sloan
J. M. Micali	H. C. Stowe
L. M. Miller	

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 28, 2014

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	SCE&G	Description
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of February 19, 2009 (Filed as Exhibit 4.04 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein)
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein)
4.03	X		First Supplemental Indenture dated as of November 1, 2009 to Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 99.01 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.04	X		Junior Subordinated Indenture dated as of November 1, 2009 between SCANA and U.S. Bank National Association, as Trustee (Filed as Exhibit 99.02 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.05	X		First Supplemental Indenture to Junior Subordinated Indenture referred to in Exhibit 4.04 dated as of November 1, 2009 (Filed as Exhibit 99.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.06		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein)
4.07		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein)
4.08		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein)
4.09		X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)

10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2008 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.03	X	X	SCANA Executive Deferred Compensation Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.04 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.04	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.05	X	X	SCANA Director Compensation and Deferral Plan (including amendments through April 21, 2011) (Filed as Exhibit 4.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.06	X	X	SCANA Long-Term Equity Compensation Plan as amended and restated (including amendments through December 31, 2009) (Filed as Exhibit 99.06 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.07	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.08	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.09	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.10	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.11		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.12	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.13	X		Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents and JPMorgan Chase Bank, N.A., Mizuho Corporation Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on October 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.14	X	X	Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); File No. 001-00375 (SCE&G)) and incorporated by reference herein)

10.15	X	X	Three-Year Credit Agreement dated as of October 25, 2012, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.16	X	X	Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and JPMorgan Chase Bank, N.A., Mizuho Corporation Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.17	X		Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on October 30, 2012 (File No. 001-08809) and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith under the heading "Corporate Structure and Organization" in Part I, Item I of this Form 10-K and incorporated by reference herein)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02	X		Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.03		X	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.04		X	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS**	X	X	XBRL Instance Document
101. SCH**	X	X	XBRL Taxonomy Extension Schema
101. CAL**	X	X	XBRL Taxonomy Extension Calculation Linkbase

101. DEF**	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB**	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE**	X	X	XBRL Taxonomy Extension Presentation Linkbase

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* Management Contract or Compensatory Plan or Arrangement

** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

Exhibit 12.01

COMPUTATION OF RATIOS
December 31, 2013

BOND RATIO

SCANA and SCE&G:

Dollars in Millions Year Ended December 31, 2013		
Net earnings as defined in SCE&G's bond indenture dated April 1, 1993 (Mortgage)		$ 1,035.8
Divide by annualized interest charges on:		
Bonds outstanding under the Mortgage	$ 196.0	
Total annualized interest charges	196.0	
Bond Ratio		5.28

RATIO OF EARNINGS TO FIXED CHARGES

Dollars in Millions	SCANA					SCE&G				
Years Ended December 31,	2013	2012	2011	2010	2009	2013	2012	2011	2010	2009
Fixed Charges as defined:										
Interest on debt	$305.9	$301.3	$287.0	$270.4	$251.5	$226.4	$217.4	$207.8	$192.4	$181.4
Amortization of debt premium, discount and expense (net)	5.3	4.9	4.8	5.1	4.8	4.2	3.9	3.9	4.0	3.8
Interest component on rentals	4.9	4.9	5.2	4.6	7.9	4.5	3.2	3.6	3.1	5.5
Preference security dividend requirement of consolidated subsidiary	—	-	-	-	14.2	-	-	-	-	-
Total Fixed Charges (A)	$316.1	$311.1	$297.0	$280.1	$278.4	$235.1	$224.5	$215.3	$199.5	$190.7
Earnings as defined:										
Pretax income from continuing operations	$693.8	$601.6	$555.6	$535.4	$524.2	$579.7	$509.5	$456.5	$433.6	$427.8
Total fixed charges above	316.1	311.1	297.0	280.1	278.4	235.1	224.5	215.3	199.5	190.7
Pretax equity in (earnings) losses of investees	(3.2)	(3.3)	(2.9)	(1.1)	(2.2)	3.5	3.8	2.3	2.1	0.1
Cash distributions from equity investees	9.6	3.3	3.6	4.8	3.3	-	-	-	-	-
Preference security dividend requirement from above	-	-	-	-	(14.2)	-	-	-	-	-
Total Earnings (B)	$1016.3	$912.7	$853.3	$819.2	$789.5	$818.3	$737.8	$674.1	$635.2	$619.0
Ratio of Earnings to Fixed Charges (B/A)	3.22	2.93	2.87	2.92	2.84	3.48	3.29	3.13	3.18	3.25

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-174796 and 333-191691 on Form S-8 and Post-Effective Amendment No. 1 to Registration Statement No. 333-37398 on Form S-8 and Registration Statement Nos. 333-184426 and 333-191756 on Form S-3 of our reports dated February 28, 2014, relating to the consolidated financial statements and financial statement schedule of SCANA Corporation and subsidiaries (the “Company”), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2013.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-184426-01 on Form S-3 of our report dated February 28, 2014, relating to the consolidated financial statements and financial statement schedule of South Carolina Electric & Gas Company and affiliates appearing in this Annual Report on Form 10-K of South Carolina Electric & Gas Company for the year ended December 31, 2013.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

Exhibit 24.01

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of SCANA Corporation ("SCANA"), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCANA's fiscal year ended December 31, 2013, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 20th day of February 2014.

/s/J. A. Bennett
J. A. Bennett
Director

/s/J. F. A. V. Cecil
J. F. A. V. Cecil
Director

/s/D. M. Hagood
D. M. Hagood
Director

/s/K. B. Marsh
K. B. Marsh
Director

/s/J. W. Martin, III
J. W. Martin, III
Director

/s/J. M. Micali
J. M. Micali
Director

/s/L. M. Miller
L. M. Miller
Director

/s/J. W. Roquemore
J. W. Roquemore
Director

/s/M. K. Sloan
M. K. Sloan
Director

/s/H. C. Stowe
H. C. Stowe
Director

/s/A. Trujillo
A. Trujillo
Director

Exhibit 24.02

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of South Carolina Electric & Gas Company ("SCE&G"), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCE&G's fiscal year ended December 31, 2013, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 20th day of February 2014.

/s/J. A. Bennett	/s/D. M. Hagood
J. A. Bennett Director	D. M. Hagood Director
/s/K. B. Marsh	/s/J. M. Micali
K. B. Marsh Director	J. M. Micali Director
/s/L. M. Miller	/s/J. W. Roquemore
L. M. Miller Director	J. W. Roquemore Director
/s/M. K. Sloan	/s/H. C. Stowe
M. K. Sloan Director	H. C. Stowe Director

Exhibit 31.01

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2014

/s/Kevin B. Marsh
Kevin B. Marsh, Chairman of the Board, President,
Chief Executive Officer and Chief Operating Officer

Exhibit 31.02

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2014

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 31.03

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2014

/s/Kevin B. Marsh
Kevin B. Marsh, Chairman of the Board and Chief Executive Officer

Exhibit 31.04

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2014

/s/Jimmy E. Addison
Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 32.01

SCANA CORPORATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the “Company”) on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes- Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 28, 2014

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board, President,
Chief Executive Officer and Chief Operating Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.02

SCANA CORPORATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the “Company”) on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes- Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 28, 2014

/s/Jimmy E. Addison
Jimmy E. Addison
Executive Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.03

SOUTH CAROLINA ELECTRIC & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of South Carolina Electric & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2014

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.04

SOUTH CAROLINA ELECTRIC & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of South Carolina Electric & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2014

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

FORM 10-K

SOUTH CAROLINA ELECTRIC & GAS CO - SCG

Filed: February 27, 2015 (period: December 31, 2014)

Annual report with a comprehensive overview of the company

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2014

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	**SCANA Corporation** (a South Carolina corporation)	**57-0784499**
1-3375	**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	**57-0248695**

Securities registered pursuant to Section 12(b) of the Act:

SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange
2009 Series A 7.70% Enhanced Junior Subordinated Notes, registered on The New York Stock Exchange (deregistered on February 3, 2015)

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $7.6 billion at June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $53.81 per share. South Carolina Electric & Gas Company is a wholly-owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 20, 2015
SCANA Corporation	Without Par Value	142,916,917
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Specified sections of SCANA Corporation's Proxy Statement, in connection with its 2015 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other company.

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;

(2) legislative and regulatory actions, particularly changes in rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;

(3) current and future litigation;

(4) changes in the economy, especially in areas served by subsidiaries of SCANA;

(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;

(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;

(7) the loss of sales to distributed generation, such as solar photovoltaic systems;

(8) growth opportunities for SCANA's regulated and diversified subsidiaries;

(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;

(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA's subsidiaries;

(11) changes in SCANA's or its subsidiaries' accounting rules and accounting policies;

(12) payment and performance by counterparties and customers as contracted and when due;

(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission, including nuclear generating facilities, and the results of efforts to operate its electric and gas systems and assets in accordance with acceptable performance standards;

(14) maintaining creditworthy joint owners for SCE&G's new nuclear generation project;

(15) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon quality and prices, for our construction program, operations and maintenance;

(16) the results of efforts to ensure the physical and cyber security of key assets and processes;

(17) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;

(18) the availability of skilled and experienced human resources to properly manage, operate, and grow the Company's businesses;

(19) labor disputes;

(20) performance of SCANA's pension plan assets;

(21) changes in taxes and tax credits, including production tax credits for new nuclear units;

(22) inflation or deflation;

(23) compliance with regulations;

(24) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and

(25) the other risks and uncertainties described from time to time in the reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of Westinghouse Electric Company LLC and CB&I Stone and Webster, Inc., a subsidiary of Chicago Bridge & Iron Company N. V.
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker
CWA	Clean Water Act
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DSM Programs	Demand Side Management Programs
ELG Rule	New federal effluent limitation guidelines for steam electric generating units
Energy Marketing	The divisions of SEMI, excluding SCANA Energy
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
eWNA	Pilot Electric WNA
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
KVA	Kilovolt ampere
kWh	Kilowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LNG	Liquefied Natural Gas

LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF or MMCF	Thousand Cubic Feet or Million Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NASDAQ	The NASDAQ Stock Market, Inc.
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
ppm	Parts per million
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	A division of SEMI which markets natural gas in Georgia
SCE&G	South Carolina Electric & Gas Company
SCEUC	South Carolina Energy Users Committee
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
Southern Natural	Southern Natural Gas Company
Spirit Communications	SCTG Communications, Inc. (a wholly owned subsidiary of SCTG, LLC) d/b/a Spirit Communications

TERM	**MEANING**
Summer Station	V. C. Summer Nuclear Station
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
Westinghouse	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

INVESTOR INFORMATION

SCANA’s and SCE&G’s annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA’s internet website at *www.scana.com* (which is not intended as an active hyperlink; the information on SCANA’s website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC) as soon as reasonably practicable after these reports are filed or furnished.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G’s new nuclear project and other matters of interest to investors on SCANA’s website. On SCANA’s homepage, there is a yellow box containing links to the Nuclear Development and Other Investor Information sections of the website. The Nuclear Development section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear Development and Other Investor Information yellow box.

CORPORATE STRUCTURE AND SEGMENTS OF BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees as of February 20, 2015 and 2014 of 5,886 and 5,989, respectively. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries except as described below, each of which is incorporated in South Carolina.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 688,000 customers and the purchase, sale and transportation of natural gas to approximately 338,000 customers (each as of December 31, 2014). SCE&G’s business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G’s electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 36 counties in South Carolina and covers approximately 23,000 square miles. More than 3.3 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 521,000 residential, commercial and industrial customers (as of December 31, 2014). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

CGT operates as an open access, transportation-only interstate pipeline company regulated by FERC. CGT operates in southeastern Georgia and in South Carolina and has interconnections with Southern Natural at Port Wentworth, Georgia and with Southern LNG, Inc. at Elba Island, near Savannah, Georgia. CGT also has interconnections with Southern Natural in Aiken County, South Carolina, and with Transco in Cherokee and Spartanburg counties, South Carolina. CGT’s customers include SCE&G (which uses natural gas for electricity generation and for gas distribution to retail customers), SEMI (which markets natural gas to industrial and sale for resale customers, primarily in the Southeast), municipalities, county gas authorities, federal and state agencies, marketers, power generators and industrial customers primarily engaged in the manufacturing or processing of ceramics, paper, metal, and textiles. In December 2014, SCANA announced that CGT would be sold to Dominion Resources, Inc. The sale closed at the end of January 2015.

Nonregulated Businesses

SEMI markets natural gas primarily in the southeast and provides energy-related services. SCANA Energy, a division of SEMI, sells natural gas to approximately 459,000 customers (as of December 31, 2014, and includes approximately 66,000 customers in its regulated division) in Georgia's natural gas market. SCANA Energy's total customer base represents an approximately 30% share of the approximately 1.6 million customers in Georgia's deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in Georgia.

SCI owns and operates a fiber optic telecommunications network, ethernet network and data center facilities in South Carolina, and through a joint venture, SCI has an additional interest in fiber in South Carolina, North Carolina and Georgia. SCI also provides tower site construction, management and rental services and sells towers in South Carolina, North Carolina and Tennessee. SCI leases fiber optic capacity, data center space and tower space to certain affiliates at market rates. In December 2014, SCANA announced that SCI would be sold to Spirit Communications. The sale closed in February 2015.

SCANA Services, Inc. provides primarily administrative and management services to SCANA's other subsidiaries.

In addition, SCANA owns two insignificant energy-related companies that are being liquidated.

For information with respect to major segments of business, see Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and the consolidated financial statements for SCANA and SCE&G (Note 12). All such information is incorporated herein by reference.

COMPETITION

For a discussion of the impact of competition, see the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity and margins earned from those sales by customer classification as percentages of electric revenues were as follows:

	Sales		Margins	
Customer Classification	**2013**	**2014**	**2013**	**2014**
Residential	44%	45%	50%	50%
Commercial	33%	32%	33%	33%
Industrial	18%	18%	14%	14%
Sales for resale	2%	2%	1%	1%
Other	3%	3%	2%	2%
Total	100%	100%	100%	100%

Sales for resale include sales to three municipalities and one electric cooperative. Short-term system sales were not significant for any period presented.

During 2014 SCE&G experienced a net increase of approximately 10,000 electric customers (growth rate of 1.4%), increasing its total electric customers to approximately 688,000 at year end.

For the period 2015-2017, SCE&G projects total territorial kWh sales of electricity to increase 1.1% annually (assuming normal weather), total retail sales growth of 1.1% annually (assuming normal weather), total electric customer base to increase 1.8% annually and territorial peak load (summer, in MW) to increase 1.9% annually. SCE&G projects a retail kWh sales decrease of approximately 3.0% and customer growth of 1.4% from 2014 to 2015. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%; however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a Unit Power Sales Agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system, which extends over a large part of the central, southern and southwestern portions of South Carolina, interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., Santee Cooper, Georgia Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. SERC is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America. For a discussion of the impact certain legislative and regulatory initiatives may have on SCE&G's transmission system, see Electric Operations within the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) were as follows:

	Cost of Fuel Used		
	2012	**2013**	**2014**
Per MMBTU:			
Nuclear	$ 0.94	$ 1.11	$ 1.01
Coal	4.49	4.28	3.90
Natural Gas	3.71	4.63	5.19
All Fuels (weighted average)	3.56	3.53	3.62
Per Ton: Coal	111.72	104.63	96.74
Per MCF: Gas	3.80	4.69	5.30

The sources and percentages of total MWh generation by each category of fuel for the preceding three years and estimates for the next three years follow:

	% of Total MWh Generated					
	Actual			Estimated		
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Coal	50%	45%	50%	47%	42%	44%
Nuclear	19%	24%	19%	20%	24%	21%
Hydro	3%	4%	3%	3%	3%	3%
Natural Gas & Oil	28%	26%	26%	28%	29%	30%
Biomass	—	1%	2%	2%	2%	2%
Total	100%	100%	100%	100%	100%	100%

In 2014, the Company used coal to generate electricity at five fossil fuel-fired plants, including its cogeneration facility located in Charleston, South Carolina. Unit trains and, in some cases, trucks and barges delivered coal to these plants. SCE&G intends to retire the coal-fired generating units at one of these plants by 2020, subject to future developments in environmental regulations, among other matters. See Item 2. PROPERTIES.

Coal is primarily obtained through long-term supply contracts. Long-term contracts exist with suppliers located in eastern Kentucky, Tennessee, Virginia, and West Virginia. These contracts provide for approximately 3.0 million tons annually. Sulfur restrictions on the contract coal range from .75% to 1.6%. These contracts expire at various times through 2016. Spot market purchases may occur when needed or when prices are believed to be favorable.

SCANA and SCE&G believe that SCE&G's operations comply with all applicable regulations relating to the discharge of sulfur dioxide and nitrogen oxide. See additional discussion at Environmental Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G, for itself and as agent for Santee Cooper, and Westinghouse are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G has to supply enriched product to Westinghouse and Westinghouse will supply nuclear fuel assemblies for Summer Station Unit 1 and the New Units. Westinghouse will be SCE&G's exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Summer Station Unit 1 and the New Units through 2033. SCE&G is dependent upon Westinghouse for providing fuel assemblies for the new AP1000 reactors in the New Units in the current and anticipated future absence of other commercially viable sources.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of its nuclear generating units.

SCE&G can store spent nuclear fuel on-site until at least 2017 and is constructing a dry cask storage facility to accommodate the spent fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available. In addition, Summer Station Unit 1 has sufficient on-site storage capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

SCE&G also uses long-term power purchase agreements to ensure that adequate power supply resources are in place to meet load obligations and reserve requirements. As of December 31, 2014, SCE&G had such agreements in place for 300 MW of capacity.

GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported were as follows:

	SCANA		SCE&G	
Customer Classification	**2013**	**2014**	**2013**	**2014**
Residential	55.6%	54.9%	43.5%	44.1%
Commercial	26.0%	26.5%	27.4%	28.2%
Industrial	12.5%	12.4%	25.6%	24.6%
Transportation Gas	5.9%	6.2%	3.5%	3.1%
Total	100.0%	100.0%	100.0%	100.0%

For the period 2015-2017, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.6% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.5%, commercial of 1.0% and industrial of 0.5%.

For the period 2015-2017, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.2% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.5%, commercial of 0.6% and industrial of 0.7%.

For the period 2015-2017, SCANA's and SCE&G's total consolidated regulated natural gas customer base is projected to increase annually 2.4% and 2.3%, respectively. During 2014 SCANA recorded a net increase of approximately 22,000 regulated gas customers (growth rate of 2.6%), increasing its regulated gas customers to approximately 859,000. Of this increase, SCE&G recorded a net increase of approximately 9,000 gas customers (growth rate of 2.8%), increasing its total gas customers to approximately 338,000 (as of December 31, 2014).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost, Supply and Curtailment Plans

SCE&G purchases natural gas under contracts with producers and marketers in both the spot and long-term markets. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2018), Transco (expiring in 2017 and 2018) and CGT (expiring in 2017, 2018, 2019, 2023 and 2026). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 212,194 MMBTU from Southern Natural, 64,652 MMBTU from Transco and 431,229 MMBTU from CGT. Additional natural gas volumes may be delivered to SCE&G's system as capacity is available through interruptible transportation.

The daily volume of gas that SEMI is entitled to transport under service agreements with CGT (expiring in 2016, 2017 and 2023) on a firm basis is 82,615 MMBTU.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $5.94 per MMBTU during 2014 and $5.27 per MMBTU during 2013.

SCE&G was allocated 5,502,600 MMBTU of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 4,657,900 MMBTU of gas were in storage on December 31, 2014. To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G supplements its supplies of natural gas with two LNG liquefaction and storage facilities. The LNG plants are capable of storing the liquefied equivalent of 1,964,600 MMBTU of natural gas. Approximately 1,844,800 MMBTU (liquefied equivalent) of gas were in storage on December 31, 2014.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2032. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 610,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $5.67 per MMBTU during 2014 compared to $5.13 per MMBTU during 2013.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, Transco and Spectra Energy provide for storage capacity of approximately 13,000,000 MMBTU. Approximately 11,000,000 MMBTU of gas were in storage under these agreements at December 31, 2014. In addition, PSNC Energy's LNG facility can store the liquefied equivalent of 1,000,000 MMBTU of natural gas with regasification capability of approximately 100,000 MMBTU per day. Approximately 900,000 MMBTU (liquefied equivalent) of gas were in storage at December 31, 2014. LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG provide for 1,300,000 MMBTU (liquefied equivalent) of storage space. Approximately 1,100,000 MMBTU (liquefied equivalent) were in storage under these agreements at December 31, 2014.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SEMI markets natural gas and provides energy-related services primarily in the Southeast. In addition, SCANA Energy, a division of SEMI, markets natural gas to approximately 459,000 customers (as of December 31, 2014) in Georgia's natural gas market. SCANA Energy's total customer base represents an approximate 30% share of the approximately

1.6 million customers in Georgia’s deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements for SCANA and SCE&G.

REGULATION

Regulatory jurisdictions to which SCANA and its subsidiaries are subject are described in the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	**License Expiration**
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

* SCE&G presently operates the Saluda hydroelectric project under an annual license while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, or may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Management’s Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and Note 2 to the consolidated financial statements for SCANA and SCE&G.

Fuel Cost Recovery Procedures

The SCPSC’s fuel cost recovery procedure determines the fuel component in SCE&G’s retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions. The definition also includes the cost of emission allowances used for sulfur dioxide, nitrogen oxide, mercury and particulates. In 2014, the South Carolina General Assembly amended the statutory definition of fuel cost thereby allowing electric utilities to recover avoided costs under the Public Utility Regulatory Policy Act of 1978. The South Carolina General Assembly further amended the fuel cost statute to allow for the recovery of costs incurred as a result of offering distributed energy resource programs and net metering to its customers as a separate component of the overall fuel factor. SCE&G may request a formal proceeding concerning its fuel costs at any time.

Fuel cost recovery procedures related to the natural gas operations of SCE&G and PSNC Energy along with related rate proceedings by the SCPSC and NCUC are described in Note 2 to the consolidated financial statements for SCANA and SCE&G.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of any new or pending regulations or standards upon existing operations cannot be predicted. For a discussion of how these regulations and standards may impact SCANA and SCE&G (including capital expenditures necessitated thereby), see the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements for SCANA and SCE&G.

OTHER MATTERS

Insurance coverage for SCE&G's nuclear units is described in Note 10 to the consolidated financial statements for SCANA and SCE&G.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to the Company, and where indicated the risk factors also relate to Consolidated SCE&G.

Commodity price changes, delays and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs) and availability. Any such changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to require the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial position.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternative forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers unable to switch to alternative fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction for environmental compliance and its construction of the New Units and associated transmission, are significant and are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of the projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in energy generation and in other internal infrastructure projects, including projects for environmental compliance. For example, SCE&G and Santee Cooper have agreed to jointly own, contract the design and construction of, and operate the New Units, which will be two 1,250 MW (1,117 MW, net) nuclear units at SCE&G's Summer Station, in pursuit of which they have committed and are continuing to commit significant resources. In addition, construction of significant new transmission infrastructure is necessary to support the New Units and is under way as an integral part of the project. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and timeframes may be affected by many variables, such as the regulatory and legal processes associated with securing approvals, permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness, and unforeseen difficulties meeting critical regulatory requirements. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects (including new baseload generation) as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, adverse changes in applicable laws and regulations, new or enhanced environmental requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. Some of the foregoing issues have been experienced in the construction of the New Units. A discussion of certain of those matters can be found under New Nuclear Construction Matters in Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for SCANA and SCE&G.

Should the construction of the New Units materially and adversely deviate from the schedules, estimates, and projections timely submitted to and approved by the SCPSC pursuant to the BLRA, the SCPSC could disallow the additional capital costs that result from the deviations to the extent that it is deemed that the Company's failure to anticipate or avoid the deviation, or to minimize the resulting expenses, was imprudent, considering the information available at the time. Depending upon the magnitude of any such disallowed capital costs, the Company could be moved to evaluate the prudency of continuation, adjustment to, or termination of the project.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to the risk that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, new joint owners cannot be secured at equivalent financial terms, or changes in the joint ownership make-up will increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows and financial condition, as well as our qualifications for applicable governmental programs and benefits, such as production tax credits, may be adversely affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e. natural gas) market risk. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract.

The Company strives to manage commodity price exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be diminished.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement, many of which are still pending final action by those federal agencies. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers, major swap participants and financial institutions, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers, major swap participants or financial institutions, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Moreover, the Company retains reporting responsibility for certain types of swaps, such as the annual reporting of trade options. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental commissions, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our business. In addition to many other aspects of our business, these requirements impact the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. Non-compliance with these requirements by third parties, such as our contractors, vendors and agents, may subject the Company and Consolidated SCE&G to operational risks and to liability. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company’s or Consolidated SCE&G’s businesses. Non-compliance with these laws and regulations could result in fines, litigation, loss of licenses or permits, mandated capital expenditures and other adverse business outcomes, as well as reputational damage, which could adversely affect the cash flows, results of operations, and financial position of the Company and Consolidated SCE&G.

Furthermore, changes in or uncertainty in monetary, fiscal, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G could be adversely impacted by changes in tax policy, such as the loss of production tax credits related to the construction of the New Units.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects, results of DSM Programs and/or increases in operating costs may lead to requests for regulatory relief, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits.

SCE&G’s electric operations in South Carolina and the Company’s gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. SCE&G’s electric transmission system and Consolidated SCE&G’s generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia’s gas delivery regulatory framework will remain unchanged as market conditions evolve.

Although we believe that we have constructive relationships with the regulators, our ability to obtain rate treatment that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing nitrogen oxide, sulfur dioxide, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. In January 2014, the EPA proposed NSPS for emissions of carbon dioxide from newly constructed fossil fuel-fired electric generating units. A proposed rule for emissions of carbon dioxide from existing units was issued on June 2, 2014, to be made final no later than June 1, 2015. Also, a number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none have yet been enacted. In April 2012 the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. In October 2014, the stay on CSAPR was lifted and CAIR was set aside, thus reinstating CSAPR sulfur dioxide and nitrogen oxide allocatons on electric generating units in 28 states, including South Carolina. In 2010, the EPA set a new NAAQS limit for sulfur dioxide and in May 2014 proposed a rule for electric generating unit compliance with that limit. In November 2014, a new NAAQS limit for ozone was proposed by the EPA. The EPA's rule for cooling water intake structures to meet the best technology available became effective in October 2014, and the EPA also issued a final rule in December 2014 regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA has proposed new standards under the CWA governing effluent limitation guidelines for electric generating units.

Compliance with these environmental laws and regulations requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as the clean-up of MGP sites or additional emission allowances) or require us to incur additional capital expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our industry, our business and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. Some states already have them, though currently South Carolina does not. Such standards could direct us to build or otherwise acquire generating capacity derived from renewable/alternative energy sources (generally, renewable energy such as biomass, solar, wind and tidal, and excluding fossil fuels, nuclear or hydro facilities). Such renewable/alternative energy may not be readily available in our service territories, if at all, and could be extremely costly to build, acquire, and operate. Resulting increases in the price of electricity to recover the cost of these types of generation, if approved by regulatory commissions, could result in lower usage of electricity by our customers. Although we cannot predict whether such standards will be adopted at the federal level or in South Carolina or their specifics if adopted, compliance with such potential portfolio standards could significantly impact our industry, our capital expenditures, and our results of operations and financial position.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In effecting compliance with MATS, SCE&G announced in 2012 that six of its oldest and smallest coal-fired units would be taken off-line or temporarily switched from coal to natural gas prior to closure. Three of these units were retired by the end of 2013 and one has been converted from coal to natural gas.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and we may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company’s and Consolidated SCE&G’s business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company’s and Consolidated SCE&G’s ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated

SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our business. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and its actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA's pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial position, including its shareholders' equity.

A downgrade in the credit rating of SCANA or any of SCANA's subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies rate SCANA's long-term senior unsecured debt, SCE&G's long-term senior secured debt, and the long-term senior unsecured debt of PSNC Energy as investment grade. In addition, ratings agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. If these rating agencies were to downgrade any of these ratings, particularly to below investment grade, borrowing cost on new issuances would increase, which would diminish financial results, and the potential pool of investors and funding sources could decrease.

SCANA's leverage ratio of long- and short-term debt to capital was approximately 57% at December 31, 2014. SCANA has publicly announced its desire to maintain its leverage ratio between 54% and 57%, but SCANA's ability to do so depends on a number of factors. In the future, if SCANA is not able to maintain its leverage ratio within the desired range, the Company's debt ratings may be affected, it may be required to pay higher interest rates on its long- and short-term indebtedness, and its ability to access the capital markets may be impaired.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and received lower prices for natural gas in deregulated markets when weather conditions have been milder than normal, and as a consequence earned less income from those operations. During 2010, the SCPSC approved SCE&G's implementation of an eWNA on a pilot basis; it was discontinued at the end of 2013. Mild weather in the future could diminish the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as electromagnetic events and the 2011 earthquake and tsunami in Japan) or man-made mishaps (such as the San Bruno, California natural gas transmission pipeline failure, the Kingston, Tennessee coal ash pond failure, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial position, operating expenses, and cash flows.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via a RTO/ISO (Regional Transmission Organization/Independent System Operator) is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should a RTO/ISO-market be implemented in the

Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new delivery transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets would be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems, which systems have undergone a rapid decline in their costs. As a result of federal and state subsidies, potential regulations allowing third-party retail sales, and advances in distributed generation technology, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and slow growth, potentially causing higher rates to customers.

The Company and SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Some economic sectors important to our customer base may be particularly affected. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally or legislative or regulatory actions. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns. For instance, improvements in battery technology, if realized, could have dramatic impacts on the viability of and growth in distributed generation.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be significantly harmed.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission equipment failure, information systems failure or security breach, the effects of drought (including reduced water levels) on the operation of emission control or other generation equipment, and the effects of a pandemic or terrorist attack on our workforce or facilities or on the ability of vendors and suppliers to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The operation of the New Units may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a natural gas line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's revenues, results of operations, and financial condition. Insurance may not be available or adequate to respond to these events.

A failure of the Company to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's financial position, results of operations and cash flows.

The Company depends on maintaining the physical and cyber security of its operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our business could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's operations are dependent in some manner upon our cyber systems, which encompass electric and gas operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, employee, or corporate information. The Company may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to respond to these events. As a result, the Company's financial position, results of operations, and cash flows may be adversely affected.

SCANA's ability to pay dividends and to make payments on SCANA's debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital .

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SEMI, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of Consolidated SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition. These risks will increase as the New Units are developed.

In 2014, Summer Station Unit 1, operated by SCE&G, provided approximately 4.6 million MWh, or 19% of our generation. When the New Units are completed, our generating capacity and the percentage of total generating capacity represented by nuclear sources are expected to increase. Hence, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;

- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident, if a major incident should occur at a domestic nuclear facility, it could harm our results of operations, cash flows and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Finally, in today’s environment, there is a heightened risk of terrorist attack on the nation’s nuclear facilities, which has resulted in increased security costs at our nuclear plant.

Failure to retain and attract key personnel could adversely affect the Company’s and Consolidated SCE&G’s operations and financial performance.

As with many other utilities, a significant portion of our workforce will be eligible for retirement during the next few years. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our business. Competition for these employees is high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. Further, the Company’s or Consolidated SCE&G’s ability to construct or maintain generation or other assets requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance. Furthermore, increased medical benefit costs of employees and retirees could adversely affect the results of operations of the Company and Consolidated SCE&G. Medical costs in this country have risen significantly over the past number of years and are expected to continue to increase at unpredictable rates. Such increases, unless satisfactorily managed by the Company and Consolidated SCE&G, could adversely affect results of operations.

The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial position, and access to capital.

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously approved by regulators), to the detriment of the Company or Consolidated SCE&G. Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company’s or Consolidated SCE&G’s interests, may have a negative effect on our results of operations, cash flows and financial position, as well as limit our ability to access capital.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards of compliance with laws and regulations, ethical conduct, operational effectiveness, customer service and the safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company’s and Consolidated SCE&G’s access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to focus on the safety of employees, customers and the public, to maintain the privacy of information related to our customers and employees and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. Social media can very rapidly convey information, whether factual or not, to large numbers of people, including customers and news media, and the failure to timely and effectively manage this media could adversely impact our reputation. The Company and Consolidated SCE&G also are committed to operational excellence, to quality customer service, and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments may subject the Company and Consolidated SCE&G not only to fraud, regulatory action, litigation and financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries. See also Note 13 to the consolidated financial statements of the Company.

SCE&G's bond indenture, securing the First Mortgage Bonds issued thereunder, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

NATURAL GAS DISTRIBUTION AND TRANSMISSION PROPERTIES

SCE&G's natural gas system includes 447 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and CGT. SCE&G's distribution system consists of 16,732 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6,180 MMBTU per day and store the liquefied equivalent of 1,009,400 MMBTU of natural gas. The Salley facility can store the liquefied equivalent of 927,000 MMBTU of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 61,800 MMBTU per day at Charleston and 92,700 MMBTU per day at Salley.

As of December 31, 2014, CGT's natural gas system consisted of over 1,400 miles of transmission pipeline of up to 24 inches in diameter. CGT's system transports gas to its customers from the transmission systems of Southern Natural at Port Wentworth, Georgia and Aiken County, South Carolina, Southern LNG, Inc. at Elba Island, near Savannah, Georgia and Transco in Cherokee and Spartanburg counties in South Carolina. In December 2014, SCANA announced that CGT would be sold. The sale closed at the end of January 2015.

PSNC Energy's natural gas system consists of 597 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy's distribution system consists of 20,799 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000,000 MMBTU, the capacity to liquefy up to 4,000 MMBTU per day and the capacity to regasify approximately 100,000 MMBTU per day. PSNC Energy also owns, through a wholly-owned subsidiary, 33.21% of Cardinal Pipeline Company, LLC, which owns a 105-mile transmission pipeline in North Carolina. In addition, PSNC Energy owns, through a wholly-owned subsidiary, 17% of Pine Needle LNG Company, LLC. Pine Needle owns and operates a liquefaction, storage and regasification facility in North Carolina.

ELECTRIC PROPERTIES

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2014.

	In-Service Date	Net Generating Capacity Summer (MW)	
Coal-Fired Steam:			
McMeekin - Irmo, SC	1958	250	*
Wateree - Eastover, SC	1970	684	
Williams - Goose Creek, SC	1973	605	
Cope - Cope, SC	1996	415	
Kapstone - Charleston, SC	1999	85	
Gas-Fired Steam - Urquhart Unit 3 - Beech Island, SC	1953	95	*
Nuclear:			
Summer Station Unit 1 - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647	
Summer Station Unit 2 and Unit 3 - Parr, SC			**
Internal Combustion Turbines:			
Peaking units - various locations in SC	1968-2010	352	
Urquhart Combined Cycle - Beech Island, SC	2002	458	

Jasper Combined Cycle - Jasper, SC	2004	852
Hydro:		
Saluda - Irmo, SC	1930	200
Other hydro units - various locations in or bordering SC	1905-1914	18
Fairfield Pumped Storage - Parr, SC	1978	576

* As described in Note 2 to the consolidated financial statements for SCANA and SCE&G, SCE&G intends to retire these units by 2020, subject to future developments in environmental regulations, among other matters. Urquhart Unit 3 was fueled with coal prior to 2013 and is expected to be fueled with natural gas until its retirement.

** SCE&G owns 55% of Unit 2 and Unit 3, which are being constructed at Summer Station.

SCE&G owns 434 substations having an aggregate transformer capacity of 29.8 million KVA. The transmission system consists of 3,411 miles of lines, and the distribution system consists of 18,442 pole miles of overhead lines and 7,122 trench miles of underground lines.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G are subject to various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on their respective results of operations, cash flows or financial condition. In addition, certain material regulatory and environmental matters and uncertainties, some of which remain outstanding at December 31, 2014, are described in the Rate Matters section of Note 2 and in the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	59	Chairman of the Board and Chief Executive Officer	2011-present
		President and Chief Operating Officer-SCANA	2011-present
		President and Chief Operating Officer-SCE&G	*-2011
Jimmy E. Addison	54	Executive Vice President-SCANA	
		Chief Financial Officer	2012-present
		President and Chief Operating Officer-SEMI	*-present
		Senior Vice President	2014-present
			*-2012
Jeffrey B. Archie	57	Senior Vice President and Chief Nuclear Officer-SCE&G	*-present
		Senior Vice President-SCANA	*-present
George J. Bullwinkel	66	President and Chief Operating Officer-SCI	
		President and Chief Operating Officer-SEMI and ServiceCare	*-2015
		Senior Vice President-SCANA	*-2014
			*-2015
Sarena D. Burch	57	Senior Vice President-Fuel Procurement and Asset Management-SCE&G	
		and PSNC Energy	*-present
		Senior Vice President-SCANA	*-present
Stephen A. Byrne	55	President-Generation and Transmission and Chief Operating Officer-SCE&G	2011-present
		Executive Vice President-SCANA	*-present
		Executive Vice President-Generation and Transmission-SCE&G	2011
		Executive Vice President-Generation, Nuclear and Fossil Hydro-SCE&G	*-2011
Paul V. Fant	61	President and Chief Operating Officer-CGT	*-2015
		Senior Vice President-SCANA	*-2015
D. Russell Harris	50	Senior Vice President-Gas Distribution-SCANA	2013-present
		President-Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		Senior Vice President-SCANA	2012-2013
Kenneth R. Jackson	58		
		Senior Vice President-Economic Development, Governmental and Regulatory Affairs	2014-present
		Senior Vice President-SCANA	2014-present
		Vice President-Rates and Regulatory Services	*-2014
W. Keller Kissam	48	President of Retail Operations-SCE&G	2011-present
		Senior Vice President-SCANA	2011-present
		Senior Vice President-Retail Operations-SCE&G	2011
		Vice President-Electric Operations-SCE&G	*-2011
Ronald T. Lindsay	64	Senior Vice President, General Counsel and Assistant Secretary	*-present
Martin K. Phalen	60	Senior Vice President-Administration-SCANA	2012-present
		Vice President-Gas Operations-SCE&G	*-2012

*Indicates positions held as least since March 1, 2010.

George J. Bullwinkel and Paul V. Fant ceased being executive officers of SCANA Corporation by February 1, 2015.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

COMMON STOCK INFORMATION

SCANA Corporation:

Price Range (NYSE Composite Listing):

	2014				2013			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 63.41	$ 53.89	$ 53.88	$ 51.39	$ 48.15	$ 52.93	$ 54.41	$ 51.23
Low	$ 47.77	$ 48.53	$ 49.51	$ 45.58	$ 44.75	$ 45.72	$ 47.22	$ 45.57

SCANA common stock trades on the NYSE using the ticker symbol SCG. Newspaper stock listings use the name SCANA. At February 20, 2015 there were 142,916,917 shares of SCANA common stock outstanding which were held by approximately 27,147 shareholders of record. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2014, see Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

SCANA declared quarterly dividends on its common stock of $0.525 per share in 2014 and $0.5075 per share in 2013. On February 19, 2015, SCANA increased the quarterly cash dividend rate on SCANA common stock to $0.545 per share, an increase of approximately 3.8%. The next quarterly dividend is payable April 1, 2015 to shareholders of record on March 10, 2015. For a discussion of provisions that could limit the payment of cash dividends, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCANA.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2014 and 2013, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount
February 20, 2013	$ 62.2 million	February 20, 2014	$ 62.5 million
April 25, 2013	62.0 million	April 24, 2014	62.8 million
July 31, 2013	65.8 million	July 31, 2014	66.8 million
October 31, 2013	60.0 million	October 30, 2014	72.5 million

On February 19, 2015, SCE&G declared a quarterly dividend on its common stock of $69.0 million.

For a discussion of provisions that could limit the payment of cash dividends, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCE&G.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2014	2013	2012	2011	2010
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$ 4,951	$ 4,495	$ 4,176	$ 4,409	$ 4,601
Operating Income	$ 1,007	$ 910	$ 859	$ 813	$ 768
Net Income	$ 538	$ 471	$ 420	$ 387	$ 376
Common Stock Data					
Weighted Average Common Shares Outstanding (Millions)	141.9	138.7	131.1	128.8	125.7
Basic Earnings Per Share	$ 3.79	$ 3.40	$ 3.20	$ 3.01	$ 2.99
Diluted Earnings Per Share	$ 3.79	$ 3.39	$ 3.15	$ 2.97	$ 2.98
Dividends Declared Per Share of Common Stock	$ 2.10	$ 2.03	$ 1.98	$ 1.94	$ 1.90
Balance Sheet Data					
Utility Plant, Net	$ 12,232	$ 11,643	$ 10,896	$ 10,047	$ 9,662
Total Assets	$ 16,852	$ 15,164	$ 14,616	$ 13,534	$ 12,968
Total Equity	$ 4,987	$ 4,664	$ 4,154	$ 3,889	$ 3,702
Short-term and Long-term Debt	$ 6,615	$ 5,825	$ 5,744	$ 5,306	$ 4,909
Other Statistics					
Electric:					
Customers (Year-End)	687,800	678,273	669,966	664,196	660,580
Total sales (Million kWh)	23,319	22,313	23,879	24,188	24,884
Generating capability-Net MW (Year-End)	5,237	5,237	5,533	5,642	5,645
Territorial peak demand-Net MW	4,853	4,574	4,761	4,885	4,735
Regulated Gas:					
Customers, excluding transportation (Year-End)	859,186	837,232	818,983	803,644	794,841
Sales, excluding transportation (Thousand Therms)	973,907	921,533	798,978	812,416	931,879
Transportation customers (Year-End)	485	496	499	492	491
Transportation volumes (Thousand Therms)	1,786,897	1,729,399	1,559,542	1,585,202	1,546,234
Retail Gas Marketing:					
Retail customers (Year-End)	459,235	454,104	449,144	455,258	464,123
Firm customer deliveries (Thousand Therms)	425,946	382,728	310,442	341,554	402,583
Nonregulated interruptible customer deliveries (Thousand Therms)	1,988,570	1,928,266	1,981,085	1,845,327	1,728,161
SCE&G:					
Statement of Income Data					
Operating Revenues	$ 3,091	$ 2,845	$ 2,809	$ 2,819	$ 2,815
Operating Income	$ 830	$ 737	$ 717	$ 654	$ 604
Net Income	$ 458	$ 391	$ 352	$ 316	$ 304
Net Income Attributable to Noncontrolling Interest	$ 12	$ 11	$ 11	$ 10	$ 14
Earnings Available to Common Shareholder	$ 446	$ 380	$ 341	$ 306	$ 290
Balance Sheet Data					
Utility Plant, Net	$ 10,783	$ 10,048	$ 9,375	$ 8,588	$ 8,198
Total Assets	$ 14,107	$ 12,700	$ 12,104	$ 11,037	$ 10,574
Total Equity	$ 4,757	$ 4,489	$ 4,043	$ 3,773	$ 3,541
Short-term and Long-term Debt	$ 5,018	$ 4,306	$ 4,171	$ 3,753	$ 3,440
Other Statistics					
Electric:					
Customers (Year-End)	687,866	678,338	670,030	664,273	660,642
Total sales (Million kWh)	23,333	22,327	23,899	24,200	24,887
Generating capability-Net MW (Year-End)	5,237	5,237	5,533	5,642	5,645
Territorial peak demand-Net MW	4,853	4,574	4,761	4,885	4,735
Regulated Gas:					
Customers, excluding transportation (Year-End)	338,274	329,179	322,419	316,683	313,346
Sales, excluding transportation (Thousand Therms)	471,596	457,119	412,163	407,073	447,057
Transportation customers (Year-End)	173	173	166	155	148
Transportation volumes (Thousand Therms)	198,733	155,190	260,215	192,492	190,931

SCANA CORPORATION

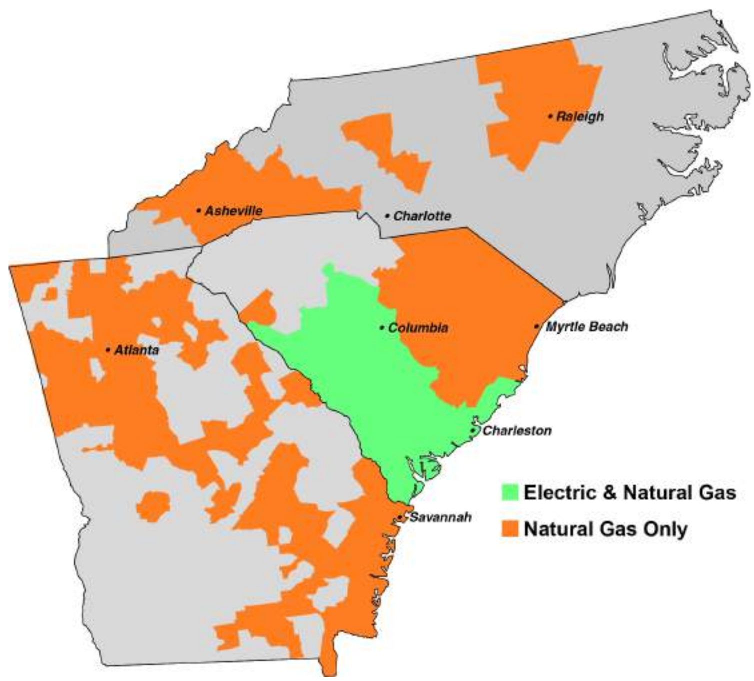
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through other wholly-owned nonregulated subsidiaries, SCANA markets natural gas to retail customers in Georgia and to wholesale customers primarily in the southeast, and also provides fiber optic and other telecommunications services. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

In December 2014 SCANA entered into agreements to sell its interstate natural gas pipeline and telecommunications subsidiaries. These sales closed in the first quarter of 2015. See Note 13 to the consolidated financial statements.

The following map indicates areas where the Company's significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect net income earned by the Company's regulated and nonregulated businesses (including the holding company) and the percentage of total assets held by them.

	2014	2013	2012
Net Income			
Regulated	98%	97%	99%
Nonregulated	2%	3%	1%
Assets			
Regulated	95%	95%	95%
Nonregulated	5%	5%	5%

Key Earnings Drivers and Outlook

During 2014, economic growth continued to improve in the southeast. Significant industrial announcements were made in the Company's South Carolina and North Carolina service territories during the year, and announcements made in previous years began to materialize. In addition, the Port of Charleston continues to see increased traffic, with container volume up 12% over 2013. The Company also experienced positive residential and commercial customer growth rates in its regulated businesses and steady unemployment rates for areas served by the Company.

Over the next five years, key earnings drivers for the Company will be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business in Georgia and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generates electricity and provides for its transmission, distribution and sale to approximately 688,000 customers (as of December 31, 2014) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control growth in costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2014 was 10.25% for non-BLRA rate base, and 11.0% for BLRA-related rate base. To prevent the need for a non-BLRA base rate increase during years of peak nuclear construction, SCE&G has a stated goal of earning a return on equity of 9% or higher. For the year ended December 31, 2014, SCE&G's earned return on equity related to non-BLRA rate base was approximately 10%.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and under an agreement signed in January 2014, SCE&G has agreed to acquire an additional 5% ownership in increments coinciding with the commercial operation date of Unit 2 and the first and second anniversaries thereof. The purchase of this additional 5% ownership is expected to be funded by increased cash flows resulting from tax deductibility of depreciation associated with the commercial operation of the New Units.

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. As of December 31, 2014, SCE&G's investment in the New Units totaled $2.7 billion, for which the financing costs on $2.425 billion have been reflected in rates under the BLRA.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018, with an approved 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The intended result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014, SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 was expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

During the third quarter of 2014, the Consortium also provided preliminary cost estimates for Units 2 and 3, principally related to delays for non-firm and non-fixed scopes of work to achieve a late 2018 substantial completion date for Unit 2 and a substantial completion date for Unit 3 approximately 12 months later. SCE&G's 55% portion of this preliminary estimate is approximately $660 million, excluding any owner's cost amounts associated with the delays, which could be $10 million per month for delays beyond the current SCPSC-approved substantial completion dates. This figure is presented in 2007 dollars and would be subject to escalation, which could be material. Further, this figure does not reflect consideration of the liquidated damages provisions of the EPC Contract which would partly mitigate any such delay-related costs. The Consortium's preliminary schedule and the cost estimate information have not been accepted by SCE&G and are under review, and SCE&G cannot predict when a revised schedule and cost estimate will be resolved with the Consortium.

Since receiving the August 2014 preliminary information, SCE&G has worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium now indicates that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. SCE&G is continuing discussions with Consortium executive management in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of December 31, 2014, 101 milestones have been completed. Three of the remaining milestones have not been or will not be completed within their 18-month contingency periods, and it is anticipated that the completion dates for a number of the other remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are now projected to exceed amounts currently approved by the SCPSC of $4.548 billion and $5.755 billion, respectively. As such, in 2015 SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. In addition, that petition is expected to include certain updated owner's costs and other capital costs, including amounts within the Consortium's preliminary cost estimate which may be the subject of dispute. As such, the petition is not expected to reflect the resolution of the above described negotiations. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

In August 2014, the IRS notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

For additional information on these and other matters, see New Nuclear Construction Matters herein and Note 2 and Note 10 to the consolidated financial statements.

Environmental

EPA regulations have a significant impact on the Company's electric operations. In 2014, several regulations were proposed or became final, including the following:

- A revised carbon standard for new power plants was proposed on January 8, 2014, which requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. This rule effectively prevents construction of new coal-fired plants without carbon capture and sequestration capabilities.
- The Clean Power Plan released on June 2, 2014 would regulate carbon dioxide emissions from existing units. This proposed rule includes state-specific goals for carbon dioxide emissions, as well as guidelines for states to follow in

developing SIPs to achieve those goals. Though it may be revised before becoming final in June 2015, the proposal gives states from one to three years from the date of any final rule to issue SIPs. The SIPs will ultimately define the specific compliance methodology that will be applied to existing units in that state.

- The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved in connection with the renewal (every five years) of state-issued NPDES permits. The ELG Rule is expected to be finalized by September 30, 2015.

- A final rule became effective October 14, 2014 that modifies requirements for existing cooling water intake structures. The Company is conducting studies and is developing or implementing compliance plans for this rule. Congress is also expected to consider further amendments to the CWA, and such legislation may include toxicity-based standards, among other things.

- On November 26, 2014 the EPA announced a proposed tightening of current NAAQS ozone standards from .075 ppm to a range between .065 and .070 ppm, and that it will take comments on a standard as low as .060 ppm. A final rule is expected in October 2015.

- New federal regulations affecting the management and disposal of CCRs were issued on December 19, 2014 and are expected to take effect in 2015. Under these regulations, CCRs will not be regulated as hazardous waste. These regulations do impose certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The above environmental initiatives and similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, the Company cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on the Company, if any. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 859,000 retail customers (as of December 31, 2014) in portions of South Carolina and North Carolina in areas covering 34,600 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control growth in costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25% for SCE&G and 10.60% for PSNC Energy.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company’s ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at such levels for the foreseeable future. The supply of natural gas from the Marcellus and Utica shale basins in West Virginia, Pennsylvania and Ohio has prompted companies unaffiliated with SCANA to propose a 550-mile pipeline that would bring natural gas from these basins to Virginia and North Carolina. If successful, the completed pipeline should drive economic development along its path, including areas within PSNC Energy's service territory, and should serve to keep natural gas competitively priced in the region.

Retail Gas Marketing

SCANA Energy, a division of SEMI, sells natural gas to approximately 459,000 customers (as of December 31, 2014) throughout Georgia. SCANA Energy’s total customer base represents approximately 30% of the customers in Georgia’s deregulated natural gas market. This market is mature, resulting in lower margins and stiff competition. Competitors include affiliates of large energy companies as well as electric membership cooperatives, among others. SCANA Energy’s ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy's operating results are highly sensitive to weather.

Approximately 66,000 of SCANA Energy's customers (as of December 31, 2014) are low-income or are unable to obtain natural gas service from other marketers. As Georgia’s regulated provider, SCANA Energy provides service to these customers at rates approved by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA Energy and certain of SCANA’s other natural gas distribution and marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA’s projected natural gas needs has been purchased or placed under contract.

Energy Marketing

The divisions of SEMI, excluding SCANA Energy, market natural gas primarily in the southeast and provide energy-related services to customers. Operating results for energy marketing are primarily influenced by customer demand for natural gas and the ability to control growth of costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, certain pipeline capacity available for Energy Marketing to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the retail market.

RESULTS OF OPERATIONS

	2014	2013	2012
Basic earnings per share	$ 3.79	$ 3.40	$ 3.20
Diluted earnings per share	$ 3.79	$ 3.39	$ 3.15
Cash dividends declared (per share)	$ 2.10	$ 2.03	$ 1.98

2014 vs 2013	Basic earnings per share increased primarily due to the effects of weather, customer growth and base rate increases under the BLRA. Higher electric and gas margins were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.
2013 vs 2012	Basic earnings per share increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.

Diluted earnings per share figures give effect to dilutive potential common stock using the treasury stock method. See Note 1 to the consolidated financial statements.

On February 19, 2015, SCANA declared a quarterly cash dividend on its common stock of $.545 per share.

As further discussed in Note 13 to the consolidated financial statements, in December 2014 SCANA announced that it would sell CGT and SCI. These sales closed in January and February 2015, respectively. In aggregate, these subsidiaries contributed basic earnings per share of $.14 in 2014, $.15 in 2013 and $.18 in 2012.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2014	Change	2013	Change	2012
Operating revenues	$ 2,629.4	8.2%	$ 2,430.5	(0.9)%	$ 2,453.1
Less: Fuel used in electric generation	799.3	6.4%	751.0	(11.0)%	844.2
Purchased power	80.7	87.7%	43.0	53.0 %	28.1
Margin	$ 1,749.4	6.9%	$ 1,636.5	3.5 %	$ 1,580.8

2014 vs 2013 Electric margin increased due to the effects of weather of $43.5 million, base rate increases under the BLRA of $54.1 million and customer growth of $14.7 million. These margin increases were partially offset by $69.0 million of downward adjustments to electric revenues in 2014 pursuant to SCPSC orders related to fuel cost recovery and SCE&G's DSM Programs. In 2013, pursuant to SCPSC orders, electric revenues were adjusted downward by $50.1 million related to fuel cost recovery and the reversal of undercollected amounts related to the Company's pilot eWNA program (eWNA was discontinued effective with the first billing cycle of 2014). Such adjustments are fully offset by the recognition within other income of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of SCE&G's storm damage reserve, both of which had been deferred in regulatory accounts. See Note 2 to the consolidated financial statements.

2013 vs 2012 Margin increased primarily due to base rate increases under the BLRA of $54.2 million and higher electric base rates of $67.3 million approved in the December 2012 rate order. Additionally, pursuant to accounting orders of the SCPSC, 2013's electric margin reflects downward adjustments of $50.1 million to revenue. Such adjustments are fully offset by the recognition within other income of gains realized upon the settlement of certain derivative interest rate contracts, which had been deferred as regulatory liabilities. See Note 2 to the consolidated financial statements.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2014	Change	2013	Change	2012
Residential	8,156	7.7%	7,571	—	7,571
Commercial	7,371	2.3%	7,205	(1.2)%	7,291
Industrial	6,234	3.9%	6,000	2.8 %	5,836
Other	600	3.3%	581	(0.9)%	586
Total retail sales	22,361	4.7%	21,357	0.3 %	21,284
Wholesale	958	0.3%	955	(63.2)%	2,595
Total Sales	23,319	4.5%	22,312	(6.6)%	23,879

2014 vs 2013 Retail sales volumes increased primarily due to the effects of weather and customer growth.

2013 vs 2012 Retail sales volume increased primarily due to customer growth and the effects of weather, partially offset by lower average use. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas Distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2014	Change	2013	Change	2012
Operating revenues	$ 1,014.0	7.6%	$ 942.6	23.2%	$ 765.0
Less: Gas purchased for resale	592.5	10.8%	534.9	42.8%	374.6
Margin	$ 421.5	3.4%	$ 407.7	4.4%	$ 390.4

2014 vs 2013 Margin increased primarily due to weather, residential and commercial customer growth of $9.1 million and increased average usage at SCE&G of $2.5 million.

2013 vs 2012 Margin increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012, as well as residential and commercial customer growth and increased industrial usage.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2014	Change	2013	Change	2012
Residential	46,207	12.0 %	41,268	24.4%	33,161
Commercial	30,701	8.9 %	28,181	12.7%	25,001
Industrial	20,343	(8.9)%	22,319	4.6%	21,340
Transportation gas	45,506	7.8 %	42,221	9.0%	38,736
Total	142,757	6.5 %	133,989	13.3%	118,238

2014 vs 2013 Total sales volumes increased primarily due to weather and residential and commercial customer growth. Industrial sales volumes decreased primarily due to weather related curtailments and a customer switching to an alternative fuel source. Transportation sales increased due to an increase in natural gas fired generation, partially offset by curtailments.

2013 vs 2012 Total sales volumes increased primarily due to customer growth, increased industrial usage and the effects of weather.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy, which operates in Georgia's natural gas market. Retail Gas Marketing operating revenues and net income were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Operating revenues	$ 514.9	10.7%	$ 465.2	12.8%	$ 412.5
Net Income	25.9	8.8%	23.8	*	10.5

* Greater than 100%

2014 vs 2013 Changes in operating revenues and net income are due to higher demand in 2014 primarily as a result of weather.

2013 vs 2012 Changes in operating revenues and net income are due to higher demand in 2013 primarily as a result of milder weather in 2012.

Energy Marketing

Energy Marketing is comprised of the Company's nonregulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net income were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Operating revenues	$ 981.5	19.9 %	$ 818.5	22.3%	$ 669.0
Net Income	5.1	(16.4)%	6.1	13.0%	5.4

2014 vs 2013 Operating revenues increased due to higher industrial sales volume and higher market prices. Net income decreased due to higher cost to serve customers during periods of pipeline constraints.

2013 vs 2012 Operating revenues and net income increased due to higher industrial sales volume and higher market prices.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Other operation and maintenance	$ 728.3	2.9%	$ 707.5	2.6%	$ 689.3
Depreciation and amortization	383.7	1.5%	378.1	6.2%	356.1
Other taxes	228.8	4.1%	219.7	6.1%	207.1

2014 vs 2013 — Other operation and maintenance expenses increased primarily due to higher electric operating expenses of $8.9 million, DSM Programs cost amortization of $2.1 million, higher labor expense of $3.5 million which includes incentive compensation and lower pension costs, storm expenses of $1.1 million and other general expenses of $1.9 million. Depreciation and amortization expense increased due to net plant additions. Other taxes increased primarily due to higher property taxes.

2013 vs 2012 — Other operation and maintenance expenses increased by $16.7 million due to incremental expenses associated with the December 2012 SCPSC rate order and by $5.7 million due to higher electric generation, transmission and distribution expenses. These increases were partially offset by lower compensation costs of $10.1 million due to reduced headcount and lower incentive compensation accruals and by other general expenses. Depreciation and amortization expense increased $13.2 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 SCPSC rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes on net property additions.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on the Company's income statements and balance sheets as follows:

Millions of dollars	2014	Change	2013	Change	2012
Income Statement Impact:					
Employee benefit costs	$ 5.0	(67.7)%	$ 15.5	*	$ 4.0
Other expense	0.2	(80.0)%	1.0	25.0 %	0.8
Balance Sheet Impact:					
Increase in capital expenditures	0.5	(93.1)%	7.2	9.1 %	6.6
Component of amount receivable from Summer Station co-owner	0.1	(96.0)%	2.5	13.6 %	2.2
Increase (decrease) in regulatory asset	(3.2)	*	5.5	(63.1)%	14.9
Net periodic benefit cost	$ 2.6	(91.8)%	$ 31.7	11.2 %	$ 28.5

* Greater than 100%

In 2013, pursuant to regulatory orders, SCE&G began recovering current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and began amortizing pension costs previously deferred in regulatory assets over approximately 30 years (for retail electric operations) and approximately 14 years (for gas operations). See further discussion in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were as follow:

Millions of dollars	2014	2013
Retail electric operations	$ 2.0	$ 2.0
Gas operations	1.0	0.2

Other Income (Expense)

Other income (expense) includes the results of certain incidental activities of regulated subsidiaries, the activities of certain non-regulated subsidiaries, and AFC. Components of other income (expense) were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Other income	$ 121.8	21.4%	$ 100.3	71.2%	$ 58.6
Other expense	(64.3)	41.3%	(45.5)	8.1%	(42.1)
Total	$ 57.5	4.9%	$ 54.8	*	$ 16.5

* Greater than 100%

2014 vs 2013 — Other income (expense) increased primarily due to the recognition of $64.0 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed, compared to $50.1 million of such gains in 2013. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

2013 vs 2012 — Changes in other income were primarily due to the recognition, pursuant to SCPSC accounting orders, of $50.1 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as regulatory liabilities. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income. This increase in other income was partially offset by the sales of communications towers that were recorded in 2012 by a non-regulated subsidiary. Changes in other expense were not significant.

AFC

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 6.1% of income before income taxes in 2014, 5.8% in 2013 and 5.4% in 2012.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Interest on long-term debt, net	$ 306.7	4.7%	$ 292.8	0.9 %	$ 290.2
Other interest expense	5.7	23.9%	4.6	(11.5)%	5.2
Total	$ 312.4	5.0%	$ 297.4	0.7 %	$ 295.4

Interest on long-term debt increased in each year primarily due to increased long-term borrowings used to finance nuclear construction, among other things. Other interest expense decreased in 2013, primarily due to reductions in principal balances outstanding on short-term debt over the prior year.

Income Taxes

Income tax expense increased in 2014 over 2013 and in 2013 over 2012 primarily due to increases in income before taxes. The Company's effective tax rate has been favorably impacted by equity AFC and certain tax credits.

LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its contractual cash obligations will be met through internally generated funds and additional short- and long-term borrowings. The Company expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

The Company obtains equity from SCANA's stock plans. In 2014, shares of SCANA common stock were acquired on behalf of participants in SCANA's Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares, rather than being purchased on the open market. This provided approximately $98 million of additional equity during 2014. Due primarily to the availability of proceeds from the sale of two subsidiaries in the first quarter of 2015, the Company began using open market purchases for its stock plans at the end of January 2015. In addition, on March 5, 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196 million.

SCANA's leverage ratio of long- and short-term debt to capital was approximately 57% at December 31, 2014. SCANA has publicly announced its desire to maintain its leverage ratio between 54% and 57%, but SCANA's ability to do so depends on a number of factors. In the future, if SCANA is not able to maintain its leverage ratio within the desired range, the Company's debt ratings may be affected, it may be required to pay higher interest rates on its long- and short-term indebtedness, and its access to capital markets may be limited.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, net of AFC, were $1.1 billion in 2014. The Company's current estimates of its capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	**2015**	**2016**	**2017**
SCE&G - Normal			
Generation	$ 158	$ 123	$ 143
Transmission & Distribution	272	251	217
Other	37	41	27
Gas	54	64	57
Common	9	12	9
Total SCE&G - Normal	530	491	453
PSNC Energy	98	123	132
Other	38	20	29
Total Normal	666	634	614
New Nuclear (including transmission)	957	928	708
Cash Requirements for Construction	1,623	1,562	1,322
Nuclear Fuel	22	145	104
Total Estimated Capital Expenditures	$ 1,645	$ 1,707	$ 1,426

Estimated capital expenditures for Nuclear Fuel in 2016 include approximately $53 million, which is SCE&G's share of nuclear fuel it acquired in 2013. This fuel has been recorded in utility plant and the corresponding liability has been recorded in long-term debt on the consolidated balance sheet.

The Company's contractual cash obligations as of December 31, 2014 are summarized as follows:

Contractual Cash Obligations	**Payments due by periods**				
Millions of dollars	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long- and short-term debt, including interest	$ 12,011	$ 1,403	$ 1,717	$ 871	$ 8,020
Capital leases	17	4	9	3	1
Operating leases	38	8	8	3	19
Purchase obligations	3,627	2,273	1,352	1	1
Other commercial commitments	3,992	881	1,787	666	658
Total	$ 19,685	$ 4,569	$ 4,873	$ 1,544	$ 8,699

As of December 31, 2014, contractual cash obligations related to CGT and SCI are excluded from the above table and were not significant. See Note 13 to the consolidated financial statements for a discussion of the sales of CGT and SCI.

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at Summer Station. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent of the cost and receiving 55 percent of the output. The estimated $500 million SCE&G expects it will cost to acquire an additional 5% ownership in the New Units is included in other commercial commitments and is further described in New Nuclear Construction Matters.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $9.6 million in 2014, and such annual payments are expected to be the same or increase to as much as $11.5 million in the future.

In addition, the Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. See further discussion at Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. At December 31, 2014, the Company had posted $21.2 million in cash collateral for such contracts. In addition, the Company had posted $131.2 million in cash collateral related to interest rate derivative contracts.

The Company also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional asset retirement obligations that are not listed in the contractual cash obligations table. See Notes 1 and 10 to the consolidated financial statements.

Financing Limits and Related Matters

The Company's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC. Financing programs currently utilized by the Company follow.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

In October 2014, the Company's existing five-year committed LOCs were extended by one year. At December 31, 2014 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $300 million, $1.2 billion, of which $500 million relates to Fuel Company, and $100 million, respectively, which expire in October 2019. In addition, at December 31, 2014 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million. SCANA entered this agreement to ensure sufficient liquidity was available to redeem its Junior Subordinated Notes on February 2, 2015. No borrowings were made under this agreement, and it expired according to its terms on February 6, 2015.

As of December 31, 2014, the Company had no outstanding borrowings under its $1.8 billion credit facilities, had approximately $918 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC supported letters of credit, and held approximately $137 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2014 were approximately $515 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2014, the Company’s long-term debt portfolio has a weighted average maturity of approximately 19 years and bears an average cost of 5.7%. Substantially all of the Company's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, the Company rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2014, approximately $67.7 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2014, the Bond Ratio was 5.41.

Financing Activities

During 2014, net cash inflows related to financing activities totaled approximately $586 million, primarily associated with the issuance of short- and long-term debt and common stock, partially offset by the repayment of long-term debt and payment of dividends. For a description of specific financing activities, see Notes 3 and 4 to the consolidated financial statements.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.70% junior subordinated notes at their face value.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G’s construction program, to finance capital expenditures, and for general corporate purposes.

Investing Activities

During 2014, the Company paid approximately $95 million to settle interest rate derivative contracts.

The Company paid approximately $6 million, net, through the third quarter of 2013 to settle interest rate derivative contracts upon the issuance of long-term debt. In addition, during the fourth quarter of 2013, the Company received approximately $120 million upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt.

For additional information, see Note 4 to the consolidated financial statements.

Major tax incentives included within recent federal legislation resulted in the allowance of 50% bonus depreciation for property placed in service for 2012 and 2013. These incentives, along with certain other deductions, have had a positive impact on the cash flows of the Company. Similar tax incentives for property placed in service for 2014 were implemented after the Company had made estimated tax payments for the 2014 tax year. As a result, these excess payments are expected to have a positive impact on the cash flows of the Company in 2015.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2014, were as follows:

December 31,	2014	2013	2012	2011	2010
SCANA	3.39	3.22	2.93	2.87	2.92

ENVIRONMENTAL MATTERS

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

For the three years ended December 31, 2014, the Company's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $51.8 million. During this same period, the Company expended approximately $31.5 million for the construction and retirement of landfills and ash ponds, net of disposal proceeds. In addition, the Company made expenditures to operate and maintain environmental control equipment at its fossil plants of $9.1 million in 2014, $9.2 million in 2013 and $10.2 million in 2012, which are included in “Other operation and maintenance” expense, and made expenditures to handle waste ash, net of disposal proceeds, of $1.6 million in 2014, $3.2 million in 2013 and $7.9 million in 2012, which are included in “Fuel used in electric generation.” In addition, included within “Other operation and maintenance” expense is an annual amortization of $1.4 million in each of 2014, 2013 and 2012 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $31.9 million for 2015 and $68.6 million for the four-year period 2016-2019. These expenditures are included in the Company's Estimated Capital

Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include the impact of possible changes in weather patterns, such as storm frequency and intensity, and the resultant potential damage to the Company's electric system, as well as impacts on employees and customers and on the Company's supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations in advance of such storms, all in order to allow the Company to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC to the extent they transact swaps as defined in Dodd-Frank.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions and other matters; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale for resale, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to issuance of short-term borrowings, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.

PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.
SCE&G and PSNC Energy	The PHMSA and the DOT as to integrity management requirements for gas distribution pipeline systems and natural gas transmission systems, respectively.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the Company's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Utility Regulation

SCANA's regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of the Company's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the Company's regulatory assets and liabilities.

The Company's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, the Company could be required to write down its investment in those assets. The Company cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect the Company's results of operations in the period in which they would be recorded. As of December 31, 2014, the Company's net investments in fossil/hydro and nuclear generation assets were approximately $2.3 billion and $3.4 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the Company's utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, the Company records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. Accounts receivable included unbilled revenues of $186.4 million at December 31, 2014 and $183.1 million at December 31, 2013, compared to total revenues of $5.0 billion and $4.5 billion for the years 2014 and 2013, respectively.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact the Company's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Asset Retirement Obligations

The Company accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from the acquisition, construction, development and normal operation in accordance with applicable accounting guidance. The Company recognizes obligations at present value in the period in which they are incurred, and capitalizes associated asset retirement costs as a part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to the Company's regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2014, the Company has recorded AROs of $201 million for nuclear plant decommissioning (as discussed above) and AROs of $362 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $2.6 million recorded in 2014 reflects the use of a 5.03% discount rate derived using a cash flow matching technique, and an assumed 8.0% long-term rate of return on plan assets. The Company believes that these assumptions were, and that the resulting pension cost amount was, reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2014 would have increased the Company’s pension cost by $1.6 million and increased the pension obligation by $0.8 million. Further, had the assumed long-term rate of return on assets been 7.75%, the Company’s pension cost for 2014 would have increased by $2.1 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

The Company determines the fair value of a large majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2014, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.4%, 6.0%, 8.3% and 9.3%, respectively. The 2014 expected long-term rate of return of 8.00% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2015, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.0%, 5.4%, 8.7% and 8.8%, respectively. For 2015, the expected rate of return is 7.50%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the significance of pension costs and the criticality of the related estimates to the Company's financial statements will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

In October 2014 the Society of Actuaries' Retirement Plans Experience Committee published a new RP-2014 mortality table and the related MP-2014 mortality improvement scale, which SCANA adopted effective December 31, 2014. The improvements in life expectancy and the projected rate of continued improvement increased postretirement benefit obligations measured at December 31, 2014, and the net periodic benefit cost to be recognized in 2015. Had SCANA not adopted this new mortality table and mortality improvement scale, the net periodic benefit cost to be recognized in 2015 would have been approximately $3.6 million and $0.2 million lower for pension and other postretirement benefit plans, respectively, and the benefit obligations would have been approximately $26.3 million and $2.7 million lower for pension and other postretirement benefit plans, respectively.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 5.19%, derived using a cash flow matching technique, and recorded a net cost of $16.9 million for 2014. Had the selected discount rate been 4.94% (25 basis points lower than the discount rate referenced above), the expense for 2014 would have been $0.6 million higher and the obligation would have been $0.2 million. Because the plan provisions include “caps” on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

NEW NUCLEAR CONSTRUCTION MATTERS

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station.

SCE&G's current ownership share in the New Units is 55%. As discussed below, under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G’s related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G’s weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2014, SCE&G’s investment in the New Units totaled $2.7 billion, for which the financing costs on $2.425 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule, including 146 milestones within that schedule, and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In

December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC also approved an 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain focus areas of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01, as well as shield building modules, are considered critical path items for both New Units. CA20 was placed on the nuclear island of Unit 2 in May 2014. The delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of Unit 2 during the first half of 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The intended result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014, SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 was expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

During the third quarter of 2014, the Consortium also provided preliminary cost estimates for Units 2 and 3, principally related to delays for non-firm and non-fixed scopes of work to achieve a late 2018 substantial completion date for Unit 2 and a substantial completion date for Unit 3 approximately 12 months later. SCE&G's 55% portion of this preliminary estimate is approximately $660 million, excluding any owner's cost amounts associated with the delays, which could be $10 million per month for delays beyond the current SCPSC-approved substantial completion dates. This figure is presented in

2007 dollars and would be subject to escalation, which could be material. Further, this figure does not reflect consideration of the liquidated damages provisions of the EPC Contract which would partly mitigate any such delay-related costs. The Consortium's preliminary schedule and the cost estimate information have not been accepted by SCE&G and are under review, and SCE&G cannot predict when a revised schedule and cost estimate will be resolved with the Consortium.

Since receiving the August 2014 preliminary information, SCE&G has worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium now indicates that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. SCE&G is continuing discussions with Consortium executive management in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of December 31, 2014, 101 milestones have been completed. Three of the remaining milestones have not been or will not be completed within their 18-month contingency periods, and it is anticipated that the completion dates for a number of the other remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are now projected to exceed amounts currently approved by the SCPSC of $4.548 billion and $5.755 billion, respectively. As such, in 2015 SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. In addition, that petition is expected to include certain updated owner's costs and other capital costs, including amounts within the Consortium's preliminary cost estimate which may be the subject of dispute. As such, the petition is not expected to reflect the resolution of the above described negotiations. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes (including any ultimate disagreements involving the preliminary cost estimates provided by the Consortium in the third quarter of 2014) through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the current milestone schedule and capital costs schedule approved by the SCPSC in November 2012, SCE&G’s estimated cost would be approximately $500 million for the additional 5% interest being acquired from Santee Cooper. This cost figure could be higher in light of the delays and related costs discussed above.

Nuclear Production Tax Credits

In August 2014, the IRS notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. SCE&G fulfilled the request related to emergency plant staffing in 2012. In addition, SCE&G prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

OTHER MATTERS

Financial Regulatory Reform

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. SCANA does not engage in significant off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provides information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2014	Expected Maturity Date							
Millions of dollars	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	161.5	110.4	9.5	718.6	8.1	4,529.7	5,537.9	6,437.4
Average Fixed Interest Rate (%)	7.48	1.14	4.62	5.95	4.97	5.29	5.35	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	133.8	155.8	151.2
Average Variable Interest Rate (%)	0.92	0.92	0.92	0.92	0.92	0.48	0.54	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	954.4	104.4	4.4	4.4	4.4	133.8	1,205.8	(256.7)
Average Pay Interest Rate (%)	3.84	3.74	6.17	6.17	6.17	4.70	3.95	—
Average Receive Interest Rate (%)	0.26	0.28	0.92	0.92	0.92	0.47	0.29	—

December 31, 2013	Expected Maturity Date							
Millions of dollars	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	46.7	10.8	109.6	8.7	717.9	4,386.5	5,280.2	5,753.3
Average Fixed Interest Rate (%)	4.83	4.72	1.14	4.84	5.95	5.43	5.40	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	138.2	160.2	154.4
Average Variable Interest Rate (%)	0.94	0.94	0.94	0.94	0.94	0.53	0.59	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	604.4	654.4	4.4	4.4	4.4	141.8	1,413.8	13.0
Average Pay Interest Rate (%)	3.97	4.17	6.17	6.17	6.17	4.72	4.16	—
Average Receive Interest Rate (%)	0.25	0.25	0.94	0.94	0.94	0.49	0.28	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above tables exclude long-term debt of $3 million at December 31, 2013 which did not have an associated stated interest rate.

For further discussion of the Company's long-term debt and interest rate derivatives, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

Commodity Price Risk

The following tables provide information about the Company's financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity:

Futures Contracts			Options	
2015	Long	Short	**2015**	Purchased Call (Long)
Settlement Price (a)	2.96	2.98	Strike Price (a)	4.17
Contract Amount (b)	23.9	0.4	Contract Amount (b)	26.1
Fair Value (b)	18.3	0.3	Fair Value (b)	0.4
2016			**2016**	
Settlement Price (a)	3.50	—	Strike Price (a)	4.14
Contract Amount (b)	1.2	—	Contract Amount (b)	2.5
Fair Value (b)	1.1	—	Fair Value (b)	0.2

(a) Weighted average, in dollars

(b) Millions of dollars

Swaps	**2015**	**2016**	**2017**	**2018**
Commodity Swaps:				
Pay fixed/receive variable (b)	69.1	19.3	6.2	3.6
Average pay rate (a)	4.2311	4.3788	4.2253	4.2421
Average received rate (a)	2.9731	3.4700	3.7733	3.9591
Fair Value (b)	48.6	15.3	5.5	3.3
Pay variable/receive fixed (b)	36.1	13.4	5.5	3.3
Average pay rate (a)	2.9869	3.4677	3.7724	3.9591
Average received rate (a)	4.2000	4.4288	4.2329	4.2471
Fair Value (b)	50.8	17.2	6.2	3.6
Basis Swaps:				
Pay variable/receive variable (b)	1.1	1.1	1.0	—
Average pay rate (a)	3.0297	3.5266	3.8036	—
Average received rate (a)	2.9926	3.5259	3.8077	—
Fair Value (b)	1.1	1.1	1.0	—

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements. The information above includes those financial positions of Energy Marketing and PSNC Energy.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy’s tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 27, 2015

SCANA Corporation
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2014	2013
Assets		
Utility Plant In Service	$ 12,289	$ 12,213
Accumulated Depreciation and Amortization	(4,088)	(4,011)
Construction Work in Progress	3,323	2,724
Plant to be Retired, Net	169	177
Nuclear Fuel, Net of Accumulated Amortization	329	310
Goodwill	210	230
Utility Plant, Net	12,232	11,643
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $122 and $150	284	317
Assets held in trust, net-nuclear decommissioning	113	101
Other investments	75	86
Nonutility Property and Investments, Net	472	504
Current Assets:		
Cash and cash equivalents	137	136
Receivables, net of allowance for uncollectible accounts of $7 and $6	838	802
Inventories:		
Fuel	221	231
Materials and supplies	139	131
Emission allowances	1	1
Prepayments	320	78
Other current assets	148	42
Assets held for sale	341	—
Total Current Assets	2,145	1,421
Deferred Debits and Other Assets:		
Regulatory assets	1,823	1,360
Pension asset	—	47
Other	180	189
Total Deferred Debits and Other Assets	2,003	1,596
Total	$ 16,852	$ 15,164

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2014	2013
Capitalization and Liabilities		
Common Stock - no par value (shares outstanding: December 31, 2014 - 142.7 million; December 31, 2013 - 140.7 million)	$ 2,378	$ 2,280
Retained Earnings	2,684	2,444
Accumulated Other Comprehensive Loss	(75)	(60)
Total Common Equity	4,987	4,664
Long-Term Debt, Net	5,531	5,395
Total Capitalization	10,518	10,059
Current Liabilities:		
Short-term borrowings	918	376
Current portion of long-term debt	166	54
Accounts payable	520	425
Customer deposits and customer prepayments	98	88
Taxes accrued	182	206
Interest accrued	83	82
Dividends declared	73	69
Liabilities held for sale	52	—
Derivative financial instruments	233	8
Other	208	134
Total Current Liabilities	2,533	1,442
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,866	1,703
Deferred investment tax credits	28	32
Asset retirement obligations	563	576
Pension and postretirement benefits	315	227
Regulatory liabilities	814	966
Other	215	159
Total Deferred Credits and Other Liabilities	3,801	3,663
Commitments and Contingencies (Note 10)		
Total	$ 16,852	$ 15,164

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31, (Millions of dollars, except per share amounts)	2014	2013	2012
Operating Revenues:			
Electric	$ 2,622	$ 2,423	$ 2,446
Gas-regulated	1,028	955	774
Gas-nonregulated	1,301	1,117	956
Total Operating Revenues	4,951	4,495	4,176
Operating Expenses:			
Fuel used in electric generation	793	745	838
Purchased power	81	43	28
Gas purchased for resale	1,729	1,491	1,198
Other operation and maintenance	728	708	690
Depreciation and amortization	384	378	356
Other taxes	229	220	207
Total Operating Expenses	3,944	3,585	3,317
Operating Income	1,007	910	859
Other Income (Expense):			
Other income	122	100	59
Other expenses	(64)	(46)	(42)
Interest charges, net of allowance for borrowed funds used during construction of $16, $14 and $11	(312)	(297)	(295)
Allowance for equity funds used during construction	33	27	21
Total Other Expense	(221)	(216)	(257)
Income Before Income Tax Expense	786	694	602
Income Tax Expense	248	223	182
Net Income	$ 538	$ 471	$ 420
Per Common Share Data			
Basic Earnings Per Share of Common Stock	$ 3.79	$ 3.40	$ 3.20
Diluted Earnings Per Share of Common Stock	3.79	3.39	3.15
Weighted Average Common Shares Outstanding (millions)			
Basic	141.9	138.7	131.1
Diluted	141.9	139.1	133.3
Dividends Declared Per Share of Common Stock	$ 2.10	$ 2.03	$ 1.98

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (Millions of dollars)	2014	2013	2012
Net Income	$ 538	$ 471	$ 420
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $(9), $4 and $(5)	(14)	7	(8)
Gain (losses) on cash flow hedging activities reclassified to interest expense, net of tax of $4, $5 and $4	7	8	6
Gain (losses) on cash flow hedging activities reclassified to gas purchased for resale, net of tax of $(2), $2 and $8	(4)	3	13
Net unrealized gains (losses) on cash flow hedging activities	(11)	18	11
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $(3), $4 and $(2)	(5)	7	(4)
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	1	1	1
Net deferred costs of employee benefit plans	(4)	8	(3)
Other Comprehensive Income (Loss)	(15)	26	8
Total Comprehensive Income	$ 523	$ 497	$ 428

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2014	2013	2012
Cash Flows From Operating Activities:			
Net Income	$ 538	$ 471	$ 420
Adjustments to reconcile net income to net cash provided from operating activities:			
Losses from equity method investments	5	7	—
Deferred income taxes, net	235	49	130
Depreciation and amortization	403	393	368
Amortization of nuclear fuel	45	57	44
Allowance for equity funds used during construction	(33)	(27)	(21)
Carrying cost recovery	(9)	(3)	—
Changes in certain assets and liabilities:			
Receivables	(33)	(38)	5
Inventories	(62)	21	(53)
Prepayments	(235)	49	26
Regulatory assets	(372)	113	(172)
Regulatory liabilities	(133)	56	62
Accounts payable	36	24	34
Taxes accrued	(24)	42	10
Pension and other postretirement benefits	133	(217)	89
Derivative financial instruments	225	(72)	3
Other assets	(8)	17	(143)
Other liabilities	19	108	37
Net Cash Provided From Operating Activities	730	1,050	839
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,092)	(1,106)	(1,077)
Proceeds from investments (including derivative collateral returned)	347	222	472
Purchase of investments (including derivative collateral posted)	(475)	(176)	(414)
Payments upon interest rate derivative contract settlement	(95)	(49)	(51)
Proceeds from interest rate derivative contract settlement	—	163	14
Net Cash Used For Investing Activities	(1,315)	(946)	(1,056)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	98	295	97
Proceeds from issuance of long-term debt	294	451	759
Repayments of long-term debt	(54)	(258)	(309)
Dividends	(294)	(281)	(257)
Short-term borrowings, net	542	(247)	(30)
Net Cash Provided From (Used For) Financing Activities	586	(40)	260
Net Increase in Cash and Cash Equivalents	1	64	43
Cash and Cash Equivalents, January 1	136	72	29
Cash and Cash Equivalents, December 31	$ 137	$ 136	$ 72
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $16, $14 and $11)	$ 301	$ 288	$ 281
—Income taxes	299	104	107
Noncash Investing and Financing Activities:			
Accrued construction expenditures	180	111	124
Capital leases	5	6	8
Nuclear fuel purchase	—	98	—

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON EQUITY

				Accumulated Other Comprehensive Income (Loss)			
	Common Stock		Retained	Gains (Losses) on Cash Flow	Deferred Employee Benefit	Total	
Millions	Shares	Amount	Earnings	Hedges	Plans	AOCI	Total
Balance as of January 1, 2012	130	$ 1,886	$ 2,097	$ (81)	$ (13)	$ (94)	$ 3,889
Net Income			420				420
Other Comprehensive Income (Loss)							
Losses arising during the period				(8)	(4)	(12)	(12)
Losses/amortization reclassified from AOCI				19	1	20	20
Total Comprehensive Income (Loss)			420	11	(3)	8	428
Issuance of Common Stock	2	97					97
Dividends Declared			(260)				(260)
Balance as of December 31, 2012	132	1,983	2,257	(70)	(16)	(86)	4,154
Net Income			471				471
Other Comprehensive Income (Loss)							
Losses arising during the period				7	7	14	14
Losses/amortization reclassified from AOCI				11	1	12	12
Total Comprehensive Income (Loss)			471	18	8	26	497
Issuance of Common Stock	9	297					297
Dividends Declared			(284)				(284)
Balance as of December 31, 2013	141	2,280	2,444	(52)	(8)	(60)	4,664
Net Income			538				538
Other Comprehensive Income (Loss)							
Losses arising during the period				(14)	(5)	(19)	(19)
Losses/amortization reclassified from AOCI				3	1	4	4
Total Comprehensive Income (Loss)			538	(11)	(4)	(15)	523
Issuance of Common Stock	2	98					98
Dividends Declared			(298)				(298)
Balance as of December 31, 2014	143	$ 2,378	$ 2,684	$ (63)	$ (12)	$ (75)	$ 4,987

Dividends declared per share of common stock were $2.10, $2.03 and $1.98 for 2014, 2013 and 2012, respectively.

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia. The Company also conducts other energy-related business and provides fiber optic communications in South Carolina.

The accompanying consolidated financial statements reflect the accounts of SCANA and the following wholly-owned subsidiaries.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	SCANA Communications, Inc.
South Carolina Generating Company, Inc.	ServiceCare, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Services, Inc.
Carolina Gas Transmission Corporation	SCANA Corporate Security Services, Inc.

CGT and SCI were sold in the first quarter of 2015. Accordingly, the assets and liabilities of these entities are aggregated and shown as Assets held for sale and Liabilities held for sale in the December 31, 2014 consolidated balance sheet. See Note 13.

The Company reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset’s life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company’s regulated subsidiaries calculated AFC using average composite rates of 7.2% for 2014, 6.9% for 2013 and 6.3% for 2012. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

The Company records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were as follows:

	2014	2013	2012
SCE&G	2.85%	2.96%	2.93%
GENCO	2.66%	2.66%	2.66%
CGT	2.11%	2.19%	2.09%
PSNC Energy	2.98%	3.01%	3.01%
Weighted average of above	2.84%	2.93%	2.90%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2014		2013	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.1 billion	—
Accumulated depreciation	$ 578.3 million	—	$ 566.9 million	—
Construction work in progress	$ 199.3 million	$ 2.7 billion	$ 127.1 million	$ 2.3 billion

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $88.9 million at December 31, 2014 and $75.6 million at December 31, 2013.

Plant to be Retired

SCE&G expects to retire three units that are or were coal-fired by 2020, subject to future developments in environmental regulations, among other matters. The net carrying value of these units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC. The net carrying value of three previously retired units is recorded in regulatory assets within unrecovered plant (see Note 2).

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued to regulatory assets in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the consolidated balance sheet (see Note 2). Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2014 and 2013, SCE&G incurred $19.4 million and $18.1 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. SCE&G accrued $1.2 million per month from July 2011 through December 2012 for its portion of the outages in the fall of 2012. Total costs for the 2012 outage were $32.3 million, of which SCE&G was responsible for $21.5 million. In connection with the SCPSC's December 2012 approval of SCE&G's retail electric rates (see Note 2), effective January 1, 2013, SCE&G began to accrue $1.4 million per month for its portion of the nuclear refueling outages that are scheduled to occur from the spring of 2014 through the spring of 2020. Total costs for the 2014 outage were $43.7 million, of which SCE&G was responsible for $29.1 million.

Goodwill

The Company considers amounts categorized by FERC as “acquisition adjustments” to be goodwill. At December 31, 2014 and 2013, assets with a carrying value of $210 million (net of writedown of $230 million) for PSNC Energy (Gas Distribution segment) were classified as goodwill. Assets with a carrying value of $20 million for CGT (All Other segment) were classified as assets held for sale as of December 31, 2014 and as goodwill as of December 31, 2013. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. The goodwill impairment testing is generally a two-step quantitative process which in step one requires estimation of the fair value of the respective reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Accounting guidance adopted by the Company gives it the option to first perform a qualitative assessment of impairment. Based on this qualitative ("step zero") assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with the two-step quantitative assessment.

In evaluations of PSNC Energy, fair value was estimated using the assistance of an independent appraisal. In evaluations of CGT, estimated fair value was obtained from discounted cash flow and other analysis as of January 1, 2014. In all evaluations for the periods presented, step one has indicated no impairment. The estimated fair values of the reporting units are substantially in excess of their carrying values, and no impairment charges have been recorded; however, should a write-down be required in the future, such a charge would be treated as an operating expense.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2014, 2013 and 2012) are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Accounts Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Inventory

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas and fuel oil. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable. Emission allowances are included in inventory at average cost. Emission allowances are expensed at weighted average cost as used and recovered through fuel cost recovery rates approved by the SCPSC.

Asset Management and Supply Service Agreements

PSNC Energy utilizes asset management and supply service agreements with counterparties for certain natural gas storage facilities. Such counterparties held 48% and 48% of PSNC Energy's natural gas inventory at December 31, 2014 and December 31, 2013, respectively, with a carrying value of $26.1 million and $22.8 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees. No fees are received under supply service agreements. The agreements expire March 31, 2015.

Income Taxes

The Company files a consolidated federal income tax return. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or revenues would be recognized by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

The Company records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

The Company presents the revenues and expenses of its regulated businesses and its retail natural gas marketing businesses (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

The Company records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $186.4 million at December 31, 2014 and $183.1 million at December 31, 2013.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy's PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented an eWNA on a pilot basis for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC. See Note 2.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

The Company computes basic earnings per share by dividing net income by the weighted average number of common shares outstanding for the period. The Company computes diluted earnings per share using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method. The Company has issued no securities that would have an antidilutive effect on earnings per share.

A reconciliation of the weighted average number of common shares for each of the three years ended December 31, for basic and diluted purposes is as follows:

In Millions	2014	2013	2012
Weighted Average Shares Outstanding—Basic	141.9	138.7	131.1
Net effect of equity forward contracts	—	0.4	2.2
Weighted Average Shares Outstanding—Diluted	141.9	139.1	133.3

New Accounting Matters

In April 2014, the Financial Accounting Standards Board issued new accounting guidance for reporting discontinued operations and disclosures of disposals of components of an entity. Under this new guidance, only those discontinued operations which represent a strategic shift that will have a major effect on an entity's operations and financial results should be reported as discontinued operations in the financial statements. As permitted, the Company adopted this new guidance for the period ended December 31, 2014.

In May 2014, the Financial Accounting Standards Board issued new accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Company will be required to adopt the new guidance in the first quarter of 2017, and early adoption is not permitted. The Company has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased. In connection with its annual review of base rates for fuel costs, and by order dated April 30, 2013, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. The order also provided for the accrual of certain debt-related carrying costs on a portion of SCE&G's under-collected balance of base fuel costs, and approved SCE&G's total fuel cost component.

Pursuant to a November 2013 SCPSC accounting order, the Company's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

By order dated April 29, 2014, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to increase its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs, which was approved by the SCPSC in March 2014. In addition, pursuant to the April 29, 2014 order, the Company's electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs during the period May 1, 2014 through April 30, 2015. See also Note 6.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The SCPSC will consider the impact of this action in future cost of fuel rate proceedings.

In October 2014, the SCPSC initiated its 2015 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 9, 2015. In connection with its January 2015 DSM Programs filing (see Electric-Base Rates herein), SCE&G notified the SCPSC that it anticipates proposing an adjustment to SCE&G's cost of fuel that, if approved, will result in an overall decrease to its base fuel costs beginning with the first billing cycle of May 2015.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term borrowing rate, and $5.8 million and $2.9 million of such carrying costs were accrued within other income during 2014 and 2013, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates, a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. In February 2013, the SCPSC denied the SCEUC's petition for rehearing and the denial was not appealed.

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G previously identified six coal-fired units that it has subsequently retired or intends to retire by 2020, subject to future developments in environmental regulations, among other matters. Three of these units had been retired by December 31, 2013, and their net carrying value is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and net lost revenues associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC approved recovery of the following amounts pursuant to annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million

Other activity related to SCE&G’s DSM Programs is as follows:

- In May 2013, the SCPSC ordered the deferral of one-half of the net lost revenues and provided for their recovery over a 12-month period beginning with the first billing cycle in May 2014.
- In April 2014, the SCPSC approved SCE&G's request to (1) recover one-half of the balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2014 and to recover the remaining balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2015, (2) utilize approximately $17.8 million of gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of the net lost revenues component of SCE&G's DSM Program rider, and (3) apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets resulting from the May 2013 order previously described.
- In addition, in April 2014 the SCPSC, upon recommendation of the ORS, reduced by 25%, or $6.6 million, the amount of net lost revenues SCE&G expects to experience over the 12-month period beginning with the first billing cycle of May 2014, and ordered that the $6.6 million be applied to decrease the amount of program costs deferred for recovery. Actual

net lost revenues not collected in the current DSM Programs rate rider are subject to true up in the following program year.

- In January 2015, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would, among other things, allow recovery of $33.0 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. In December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million
2012	2.3%	$52.1 million

Gas

SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2014	0.6% Decrease	$2.6 million
2013	No change	
2012	2.1% Increase	$7.5 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2014 and 2013 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each review period were reasonable and prudent.

PSNC Energy

PSNC Energy is subject to a Rider D rate mechanism which allows it to recover from customers all prudently incurred gas costs and certain uncollectible expenses related to gas cost. The Rider D rate mechanism also allows PSNC Energy to recover, in any manner authorized by the NCUC, losses on negotiated gas and transportation sales.

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

In September 2014, in connection with PSNC Energy's 2014 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2014.

In 2013, the State of North Carolina passed legislation that changed statutes covering income taxes, among other things. In December 2013, the NCUC issued an order notifying utilities that the incremental revenue requirement impact associated with the change in the level of state income tax expense included in each utility's cost of service would be deemed to be collected on a provisional basis (subject to refund) beginning January 1, 2014. On May 13, 2014, the NCUC issued an order requiring utilities to adjust rates to reflect changes in the state corporate income tax rate and to file a proposal to refund amounts collected on a provisional basis. Pursuant to the order, PSNC Energy lowered its rates effective July 1, 2014, and notwithstanding a subsequent reversal of the NCUC's order, PSNC Energy expects to refund amounts collected on a provisional basis through the normal operation of its Rider D rate mechanism. At December 31, 2014, these amounts were not significant.

Regulatory Assets and Regulatory Liabilities

The Company's cost-based, rate-regulated utilities recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2014**	**2013**
Regulatory Assets:		
Accumulated deferred income taxes	$ 284	$ 259
Under-collections—electric fuel adjustment clause	20	18
Environmental remediation costs	40	41
AROs and related funding	366	368
Franchise agreements	26	31
Deferred employee benefit plan costs	350	238
Planned major maintenance	2	—
Deferred losses on interest rate derivatives	453	124
Deferred pollution control costs	36	37
Unrecovered plant	137	145
DSM Programs	56	51
Other	53	48
Total Regulatory Assets	$ 1,823	$ 1,360
Regulatory Liabilities:		
Accumulated deferred income taxes	$ 22	$ 24
Asset removal costs	703	695
Storm damage reserve	6	27
Monetization of bankruptcy claim	—	29
Deferred gains on interest rate derivatives	82	181
Planned major maintenance	—	10
Other	1	—
Total Regulatory Liabilities	$ 814	$ 966

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by the Company, and are expected to be recovered over periods of up to approximately 25 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on an SCPSC order, SCE&G is recovering these amounts through cost of service rates through 2020.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil-fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects and accrues $18.4 million annually for fossil-fueled turbine/generation equipment maintenance, and collects and accrues $17.2 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2038. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense over periods up to approximately 50 years except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC. Also, in 2014, as discussed above at Rate Matters - Electric - Cost of Fuel and Rate Matters - Electric - Base Rates, certain of these deferred amounts were applied to offset under-collected fuel balances and unrecorded net lost revenues related to DSM Programs.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at certain coal-fired generating plants pursuant to specific regulatory orders. Such costs are being recovered through utility rates through 2045.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2014 SCPSC order, deferred costs are currently being recovered over approximately ten years through an approved rate rider. See Rate Matters - Electric - Base Rates above for details regarding the 2014 filing with the SCPSC regarding recovery of these deferred costs.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the non-legal obligation to remove assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely. In 2014, $16.8 million of the reserve was applied to offset incremental storm damage costs. Also, as discussed above at Rate Matters - Electric - Base Rates, in April 2014 $5.0 million of the reserve was applied to offset unrecovered net lost revenues related to DSM Programs.

The monetization of bankruptcy claim represented proceeds from the sale of a bankruptcy claim which was being amortized into operating revenue through February 2024. The balance at December 31, 2014 has been reclassified to Liabilities held for sale (see Note 13).

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. COMMON EQUITY

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2014 and 2013, retained earnings of approximately $67.7 million and $63.1 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

Authorized shares of common stock were 200 million as of December 31, 2014 and 2013.

SCANA issued common stock valued at $99.3 million, $100.9 million and $97.7 million (when issued) during the years ended December 31, 2014, 2013 and 2012, respectively, to satisfy the requirements of various compensation and dividend reinvestment plans. In addition, in March 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196.2 million.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

Dollars in millions	Maturity	2014 Balance	2014 Rate	2013 Balance	2013 Rate
Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%
Senior Notes (unsecured) (a)	2015 - 2034	88	0.93%	92	0.94%
First Mortgage Bonds (secured)	2018 - 2064	3,840	5.56%	3,540	5.60%
Junior Subordinated Notes (unsecured) (b)	2065	150	7.92%	150	7.92%
GENCO Notes (secured)	2015 - 2024	227	5.90%	233	5.89%
Industrial and Pollution Control Bonds (c)	2028 - 2038	122	3.51%	158	3.83%
Senior Debentures	2020 - 2026	350	5.93%	350	5.93%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other	2015 - 2027	17	2.90%	20	2.73%
Total debt		5,694		5,443	
Current maturities of long-term debt		(166)		(54)	
Unamortized premium		3		6	
Total long-term debt, net		$ 5,531		$ 5,395	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%)
(b) Redeemed at par prior to maturity on February 2, 2015, and included in the current portion of long-term debt on the balance sheet at December 31, 2014.
(c) Includes variable rate debt of $67.8 million at December 31, 2014 (rate of 0.04%) and 2013 (rate of 0.11%) which are hedged by fixed swaps.

The annual amounts of long-term debt maturities for the next five years are summarized as follows:

Year	Millions of dollars
2015	$ 166
2016	115
2017	14
2018	723
2019	13

Substantially all of SCE&G's and GENCO's electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2014, the Bond Ratio was 5.41.

Lines of Credit and Short-Term Borrowings

At December 31, 2014 and 2013, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

	SCANA		SCE&G		PSNC Energy	
Millions of dollars	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Lines of Credit:						
Total committed long-term	$ 300	300	1,400	1,400	100	100
Outstanding commercial paper (270 or fewer days)	$ 179	$ 125	$ 709	$ 251	$ 30	—
Weighted average interest rate	0.54%	0.39%	0.52%	0.27%	0.65%	—
Letters of credit supported by LOC	$ 3	$ 3	$ 0.3	$ 0.3	—	—
Available	$ 118	$ 172	$ 691	$ 1,149	$ 70	$ 100

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to five-year credit agreements in the amounts of $300 million, $1.2 billion (of which $500 million relates to Fuel Company) and $100 million, respectively. In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In October 2014, the term of the five-year agreements was extended by one year, such that they expire in October 2019. The three-year agreement expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1.8 billion credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9%, and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million. SCANA entered this agreement to ensure sufficient liquidity was available to redeem its junior subordinated notes on February 2, 2015. No borrowings were made under this agreement, and it expired according to its terms on February 6, 2015.

The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

The Company pays fees to the banks as compensation for maintaining committed lines of credit. Such fees were not material in any period presented.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	2014	2013	2012
Current taxes:			
Federal	$ 38	$ 161	$ 103
State	(4)	17	10
Total current taxes	34	178	113
Deferred taxes, net:			
Federal	184	39	72
State	34	10	14
Total deferred taxes	218	49	86
Investment tax credits:			
Amortization of amounts deferred-state	(1)	(1)	(14)
Amortization of amounts deferred-federal	(3)	(3)	(3)
Total investment tax credits	(4)	(4)	(17)
Total income tax expense	$ 248	$ 223	$ 182

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2014	2013	2012
Net income	$ 538	$ 471	$ 420
Income tax expense	248	223	182
Total pre-tax income	$ 786	$ 694	$ 602
Income taxes on above at statutory federal income tax rate	$ 275	$ 243	$ 211
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	24	22	19
State investment tax credits (less federal income tax effect)	(5)	(5)	(13)
Allowance for equity funds used during construction	(11)	(9)	(8)
Deductible dividends—Stock Purchase Savings Plan	(10)	(10)	(9)
Amortization of federal investment tax credits	(3)	(3)	(3)
Section 41 tax credits	(3)	—	—
Section 45 tax credits	(9)	(5)	(5)
Domestic production activities deduction	(7)	(11)	(9)
Other differences, net	(3)	1	(1)
Total income tax expense	$ 248	$ 223	$ 182

The tax effects of significant temporary differences comprising the Company's net deferred tax liability are as follows:

Millions of dollars	2014	2013
Deferred tax assets:		
Nondeductible accruals	$ 127	$ 84
Asset retirement obligation, including nuclear decommissioning	216	220
Financial instruments	40	32
Unamortized investment tax credits	17	19
Regulatory liability, net gain on interest rate derivative contracts settlement	—	27
Monetization of bankruptcy claim	10	11
Other	10	13
Total deferred tax assets	420	406
Deferred tax liabilities:		
Property, plant and equipment	$ 1,928	$ 1,765
Deferred employee benefit plan costs	107	63
Regulatory asset, asset retirement obligation	122	121
Deferred fuel costs	27	25
Regulatory asset, unrecovered plant	53	55
Regulatory asset, net loss on interest rate derivative contracts settlement	21	—
Demand side management costs	21	21
Prepayments	27	25
Other	45	38
Total deferred tax liabilities	2,351	2,113
Net deferred tax liability	$ 1,931	$ 1,707

During the third quarter of 2013, the State of North Carolina passed legislation that lowered the state corporate income tax rate from 6.9% to 6.0% in 2014 and 5.0% in 2015. In connection with this change in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The change in income tax rates did not and is not expected to have a material impact on the Company's financial position, results of operations or cash flows. Additionally, during the third quarter of 2013, the IRS issued final regulations regarding the capitalization of certain costs for income tax purposes and re-proposed certain other related regulations (collectively referred to as tangible personal property regulations). Related IRS revenue procedures were then issued on January 24, 2014. These regulations did not and are not expected to, have a material impact on the Company's financial position, results of operations or cash flows.

The Company files a consolidated federal income tax return, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company's federal returns through 2004, and the Company's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2012. With few exceptions, the Company is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	2014	2013	2012
Unrecognized tax benefits, January 1	$ 3	—	$ 38
Gross increases—uncertain tax positions in prior period	—	—	—
Gross decreases—uncertain tax positions in prior period	—	—	(38)
Gross increases—current period uncertain tax positions	13	$ 3	—
Settlements	—	—	—
Lapse of statute of limitations	—	—	—
Unrecognized tax benefits, December 31	$ 16	$ 3	$ —

In connection with the change in method of tax accounting for certain repair costs in prior years, the Company had previously recorded an unrecognized tax benefit. During the first quarter of 2012, the publication of new administrative guidance from the IRS allowed the Company to recognize this benefit. Since this change was primarily a temporary difference, the recognition of this benefit did not have a significant effect on the Company's effective tax rate.

During 2013 and 2014, the Company amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, the Company recorded an unrecognized tax benefit of $16 million. If recognized, $13 million of the tax benefit would affect the Company's effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $2 million within the next 12 months. It is also reasonably possible that this tax benefit may decrease by $7 million within the next 12 months. No other material changes in the status of the Company's tax positions have occurred through December 31, 2014.

As of December 31, 2014, prepayments primarily relates to the late 2014 extension of the 50% bonus depreciation deduction. Further, a current deferred tax liability of $51.3 million related to the sales of CGT and SCI is included within other current liabilities.

The Company recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit in 2012, during 2012 the Company reversed $2 million of interest expense which had been accrued during 2011. The Company has not recorded interest expense or penalties associated with uncertain tax positions in 2013 or 2014.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. The Company recognizes changes in the fair value of derivative instruments either in earnings, as a component of other comprehensive income (loss) or, for regulated subsidiaries, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Company's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statement of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and swaps and NYMEX futures and options. PSNC Energy's tariffs also include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SEMI, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

The Company may use interest rate swaps to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which the Company synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, the Company may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For the holding company or nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders issued in 2013, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders issued in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel balances in April 2014. The SCPSC also approved SCE&G’s request to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G’s DSM Program rider and apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)			
Hedge designation	**Gas Distribution**	**Retail Gas Marketing**	**Energy Marketing**	**Total**
As of December 31, 2014				
Commodity	6,840,000	7,951,000	3,446,720	18,237,720
Energy Management (a)	—	—	37,495,339	37,495,339
Total (a)	6,840,000	7,951,000	40,942,059	55,733,059
As of December 31, 2013				
Commodity	6,070,000	6,726,000	2,560,000	15,356,000
Energy Management (b)	—	—	27,359,958	27,359,958
Total (b)	6,070,000	6,726,000	29,919,958	42,715,958

(a) Includes an aggregate 933,893 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 348,453 MMBTU related to basis swap contracts in Energy Marketing.

The Company was party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $124.4 million at December 31, 2014, and $128.8 million at December 31, 2013. The Company was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.1 billion and $1.3 billion at December 31, 2014 and 2013, respectively.

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments	**Asset Derivatives**		**Liability Derivatives**	
Millions of dollars	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
As of December 31, 2014				
Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$ 5
			Other deferred credits and other liabilities	28
Commodity contracts			Other current assets	1
			Derivative financial instruments	11
Total				$ 45
Not designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$ 207
			Other deferred credits and other liabilities	17
Commodity contracts	Other current assets	$ 1		
Energy management contracts	Other current assets	15	Other current assets	5
			Derivative financial instruments	10
	Other deferred debits and other assets	5	Other deferred credits and other liabilities	5
Total		$ 21		$ 244
As of December 31, 2013				
Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$ 5
			Other deferred credits and other liabilities	14
Commodity contracts	Other current assets	$ 2		
Total		$ 2		$ 19
Not designated as hedging instruments				
Interest rate contracts	Other current assets	$ 13	Derivative financial instruments	$ 1
	Other deferred debits and other assets	19		
Commodity contracts	Other current assets	2		
Energy management contracts	Other current assets	4	Derivative financial instruments	4
	Other deferred debits and other assets	4	Other deferred credits and other liabilities	4
Total		$ 42		$ 9

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)		Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount	
Year Ended December 31, 2014					
Interest rate contracts	$	(9)	Interest expense	$	(3)
Year Ended December 31, 2013					
Interest rate contracts	$	106	Interest expense	$	(3)
Year Ended December 31, 2012					
Interest rate contracts	$	84	Interest expense	$	(3)

Millions of dollars	Gain or (Loss) Recognized in OCI, net of tax (Effective Portion)		Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion) Location	Amount	
Year Ended December 31, 2014					
Interest rate contracts	$	(6)	Interest expense	$	(7)
Commodity contracts		(8)	Gas purchased for resale		4
Total	$	(14)		$	(3)
Year Ended December 31, 2013					
Interest rate contracts	$	5	Interest expense	$	(8)
Commodity contracts		2	Gas purchased for resale		(3)
Total	$	7		$	(11)
Year Ended December 31, 2012					
Interest rate contracts	$	(4)	Interest expense	$	(6)
Commodity contracts		(4)	Gas purchased for resale		(13)
Total	$	(8)		$	(19)

As of December 31, 2014, the Company expects that during the next 12 months reclassifications from accumulated other comprehensive loss to earnings arising from cash flow hedges will include approximately $10.0 million as an increase to gas cost and approximately $7.1 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2014, all of the Company's commodity cash flow hedges settle by their terms before the end of 2017.

As of December 31, 2014, the Company expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.3 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gain (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

Millions of dollars	Loss Recognized in Income Location	Year Ended December 31, 2014	2013	2012	
Commodity contracts	Gas purchased for resale	—	—	$	(1)

Millions of dollars	Gain (Loss) Deferred in Regulatory Accounts		Gain Reclassified from Deferred Accounts into Income Location		Amount
Year Ended December 31, 2014					
Interest rate contracts	$	(352)	Other income	$	64
Year Ended December 31, 2013					
Interest rate contracts	$	39	Other income	$	50
Year Ended December 31, 2012					
Interest rate contracts		—			—

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2014, the Company expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $5.2 million as an increase to other income.

Credit Risk Considerations

The Company limits credit risk in its commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, the Company uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. The Company uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with the Company's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of the Company's derivative instruments contain contingent provisions that require the Company to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2014 and 2013, the Company had posted $152.4 million and $26.8 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months is recorded in Other Current Assets on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2014 and 2013, the Company would have been required to post an additional $129.8 million and $- million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2014 and 2013, are $282.2 million and $25.2 million, respectively.

In addition, as of December 31, 2014 and December 31, 2013, the Company has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2014 and December 31, 2013, the Company could request $- million and $34.1 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2014 and December 31, 2013 is $- million and $34.1 million, respectively. In addition, at December 31, 2014, the Company could have called on letters of credit in the amount of $9.2 million related to $20 million in commodity derivatives that are in a net asset position, compared to letters of credit of $6 million related to derivatives of $6 million at December 31, 2013, if all the contingent features underlying these instruments had been fully triggered.

Information related to the Company's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2014						
Commodity	$ 1	—	$ 1	—	—	$ 1
Energy Management	20	—	20	—	—	20
Total	$ 21	—	$ 21	—	—	$ 21

Balance sheet location	Other current assets	$ 16
	Other deferred debits and other assets	5
	Total	$ 21

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2013						
Interest rate	$ 32	—	$ 32	$ (1)	—	$ 31
Commodity	4	—	4	—	—	4
Energy Management	8	—	8	—	—	8
Total	$ 44	—	$ 44	$ (1)	—	$ 43

Balance sheet location	Other current assets	$ 21
	Other deferred debits and other assets	23
	Total	$ 44

Offsetting Derivative Liabilities

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2014						
Interest rate	$ 257	—	$ 257	—	$ (131)	$ 126
Commodity	12	—	12	—	(10)	2
Energy Management	20	—	20	—	(11)	9
Total	$ 289	—	$ 289	—	$ (152)	$ 137

Balance sheet location	Other current assets	$ 6
	Derivative financial instruments	233
	Other deferred credits and other liabilities	50
	Total	$ 289

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Posted	Net Amount
As of December 31, 2013						
Interest rate	$ 20	—	$ 20	$ (1)	$ (19)	—
Energy Management	8	—	8	—	(6)	$ 2
Total	$ 28	—	$ 28	$ (1)	$ (25)	$ 2

Balance sheet location	Derivative financial instruments	$ 10
	Other deferred credits and other liabilities	18
	Total	$ 28

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

The Company values available for sale securities using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. The Company's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2014		As of December 31, 2013	
Millions of dollars	**Level 1**	**Level 2**	**Level 1**	**Level 2**
Assets:				
Available for sale securities	$ 13	—	$ 9	—
Interest rate contracts	—	—	—	$ 32
Commodity contracts	1	—	2	2
Energy management contracts	—	$ 20	1	7
Liabilities:				
Interest rate contracts	—	257	—	20
Commodity contracts	1	11	—	—
Energy management contracts	5	18	—	12

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2014 and December 31, 2013 were as follows:

	As of December 31, 2014		As of December 31, 2013	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 5,697.2	$ 6,592.1	$ 5,449.3	$ 5,916.3

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

The Company sponsors a noncontributory defined benefit pension plan covering substantially all regular, full-time employees hired before January 1, 2014. Benefits are no longer offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. The Company's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The Company's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, the Company provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost. Employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2014**	**2013**	**2014**	**2013**
Benefit obligation, January 1	$ 823.0	$ 931.6	$ 238.0	$ 265.3
Service cost	20.0	21.8	4.6	5.9
Interest cost	40.4	38.5	12.0	11.1
Plan participants' contributions	—	—	2.2	2.6
Actuarial (gain) loss	100.1	(83.4)	23.5	(35.1)
Benefits paid	(64.0)	(60.0)	(12.1)	(11.8)
Curtailment	—	(25.5)	—	—
Benefit obligation, December 31	$ 919.5	$ 823.0	$ 268.2	$ 238.0

The accumulated benefit obligation for pension benefits was $888.3 million at the end of 2014 and $796.4 million at the end of 2013. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	**2013**	**2014**	**2013**
Annual discount rate used to determine benefit obligation	4.20%	5.03%	4.30%	5.19%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.75%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $1.1 million at December 31, 2014 and by $1.3 million at December 31, 2013. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $1.0 million at December 31, 2014 and by $1.2 million at December 31, 2013.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	**2014**	**2013**	**2014**	**2013**
Fair value of plan assets	$ 861.8	$ 870.0	—	—
Benefit obligation	919.5	823.0	$ 268.2	$ 238.0
Funded status	$ (57.7)	$ 47.0	$ (268.2)	$ (238.0)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2014	2013	2014	2013
Current liability	—	—	$ (11.2)	$ (11.5)
Noncurrent asset	—	$ 47.0	—	—
Noncurrent liability	$ (57.7)	—	(257.0)	(226.5)

Amounts recognized in accumulated other comprehensive loss (a component of common equity) as of December 31, 2014 and 2013 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2014	2013	2014	2013
Net actuarial loss	$ 8.1	$ 5.2	$ 3.0	$ 1.7
Prior service cost	0.3	0.5	0.1	0.1
Total	$ 8.4	$ 5.7	$ 3.1	$ 1.8

Amounts recognized in regulatory assets as of December 31, 2014 and 2013 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2014	2013	2014	2013
Net actuarial loss	$ 222.1	$ 124.8	$ 43.8	$ 24.4
Prior service cost	9.6	12.8	0.6	0.9
Total	$ 231.7	$ 137.6	$ 44.4	$ 25.3

In connection with the joint ownership of Summer Station, as of December 31, 2014 and 2013, the Company recorded within deferred debits $17.8 million and $14.1 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2014 and 2013, the Company also recorded within deferred debits $15.1 million and $12.6 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2014	2013
Fair value of plan assets, January 1	$ 870.0	$ 799.1
Actual return on plan assets	55.8	130.9
Benefits paid	(64.0)	(60.0)
Fair value of plan assets, December 31	$ 861.8	$ 870.0

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan is closed to new entrants effective January 1, 2014, and benefit accruals will cease effective January 1, 2024. In addition, during 2013, the Company adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs in connection with the amendments to the plan.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The Company's pension plan asset allocation at December 31, 2014 and 2013 and the target allocation for 2015 are as follows:

	Percentage of Plan Assets		
	Target Allocation	At December 31,	
Asset Category	2015	2014	2013
Equity Securities	58%	57%	59%
Fixed Income	33%	34%	32%
Hedge Funds	9%	9%	9%

For 2015, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes an asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy adopted for 2013.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2014 and 2013, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using						
Millions of dollars	Total	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	December 31, 2014			*December 31, 2013*			
Common stock	—	—	—	$ 332	$ 332	—	—
Preferred stock	—	—	—	1	1	—	—
Mutual funds	$ 622	$ 622	—	305	20	$ 285	—
Short-term investment vehicles	20	20	—	19	—	19	—
US Treasury securities	6	6	—	33	—	33	—
Corporate debt securities	86	86	—	53	—	53	—
Loans secured by mortgages	—	—	—	12	—	12	—
Municipals	15	15	—	4	—	4	—
Limited partnerships	32	32	—	35	1	34	—
Multi-strategy hedge funds	81	—	$ 81	76	—	—	$ 76
	$ 862	$ 781	$ 81	$ 870	$ 354	$ 440	$ 76

At December 31, 2014, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2014 or 2013.

The pension plan values common stock, preferred stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	**2014**	**2013**
Beginning Balance	$ 76	$ 70
Unrealized gains included in changes in net assets	5	6
Purchases, issuances, and settlements	—	—
Ending Balance	$ 81	$ 76

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from the Company's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2015	$ 63.4	$ 11.5
2016	64.5	12.4
2017	65.6	13.1
2018	66.1	13.8
2019	65.1	14.6
2020-2024	338.4	81.8

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, the Company does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

The Company records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Service cost	$ 20.0	$ 21.8	$ 19.6	$ 4.6	$ 5.9	$ 4.8
Interest cost	40.4	38.5	43.0	12.0	11.1	11.9
Expected return on assets	(66.7)	(61.4)	(59.5)	n/a	n/a	n/a
Prior service cost amortization	4.1	6.0	7.0	0.3	0.7	0.9
Amortization of actuarial losses	4.8	16.9	18.4	—	3.3	1.4
Transition obligation amortization	—	—	—	—	0.3	0.7
Curtailment	—	9.9	—	—	—	—
Net periodic benefit cost	$ 2.6	$ 31.7	$ 28.5	$ 16.9	$ 21.3	$ 19.7

In connection with regulatory orders, in 2013 SCE&G began recovering current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). SCE&G is amortizing previously deferred pension costs as further described in Note 2.

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Current year actuarial (gain) loss	$ 3.1	$ (5.0)	$ 1.7	$ 1.3	$ (1.8)	$ 2.0
Amortization of actuarial losses	(0.2)	(0.5)	(0.6)	—	(0.2)	—
Amortization of prior service cost	(0.2)	(0.2)	(0.2)	—	—	—
Prior service cost (credit)	—	(0.3)	—	—	—	—
Amortization of transition obligation	—	—	—	—	(0.1)	(0.1)
Total recognized in OCI	$ 2.7	$ (6.0)	$ 0.9	$ 1.3	$ (2.1)	$ 1.9

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Current year actuarial (gain) loss	$ 101.3	$ (157.5)	$ 45.0	$ 19.4	$ (29.9)	$ 31.4
Amortization of actuarial losses	(4.0)	(14.7)	(16.0)	—	(2.7)	(1.2)
Amortization of prior service cost	(3.2)	(5.2)	(6.4)	(0.3)	(0.6)	(0.8)
Prior service cost (credit)	—	(8.9)	—	—	—	—
Amortization of transition obligation	—	—	—	—	(0.2)	(0.5)
Total recognized in regulatory assets	$ 94.1	$ (186.3)	$ 22.6	$ 19.1	$ (33.4)	$ 28.9

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
Discount rate	5.03%	4.10%/5.07%	5.25%	5.19%	4.19%	5.35%
Expected return on plan assets	8.00%	8.00%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.75%/3.00%	4.00%	3.75%	3.75%	4.00%
Health care cost trend rate	n/a	n/a	n/a	7.40%	7.80%	8.20%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013 was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are as follows:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 0.5	$ 0.1
Prior service cost	0.1	—
Total	$ 0.6	$ 0.1

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2015 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 12.3	$ 1.9
Prior service cost	3.6	0.3
Total	$ 15.9	$ 2.2

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

Stock Purchase Savings Plan

The Company sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. The Company provides 100% matching contributions up to 6% of an employee’s eligible earnings. Total matching contributions made to the plan were $25.8 million in 2014, $23.4 million in 2013 and $22.3 million in 2012 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA’s common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

Liability Awards

The 2012-2014, 2013-2015 and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. In each performance cycle, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to exceptions for retirement, death, disability or change in control. The remaining 80% of the award was granted in performance shares, which are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to exceptions for retirement, death or disability. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Payouts of performance share awards are determined by SCANA’s performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in “GAAP-adjusted net earnings per share from operations” (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2012-2014 performance cycle were paid in cash at SCANA’s discretion in February 2015. Cash-settled liabilities related to the performance cycles were paid totaling approximately $11.8 million in 2014, $12.2 million in 2013, and $11.8 million in 2012.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling approximately $20.3 million in 2014, $8.7 million in 2013 and $15.0 million in 2012. Fair value adjustments resulted in capitalized compensation costs of $3.1 million in 2014, $1.4 million in 2013 and $2.7 million in 2012.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Company's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station.

SCE&G's current ownership share in the New Units is 55%. As discussed below, under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2014, SCE&G's investment in the New Units totaled $2.7 billion, for which the financing costs on $2.425 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule, including 146 milestones within that schedule, and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC also approved an 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain focus areas of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01, as well as shield building modules, are considered critical path items for both New Units. CA20 was placed on the nuclear island of Unit 2 in May 2014. The delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of Unit 2 during the first half of 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The intended result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014, SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 was expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

During the third quarter of 2014, the Consortium also provided preliminary cost estimates for Units 2 and 3, principally related to delays for non-firm and non-fixed scopes of work to achieve a late 2018 substantial completion date for Unit 2 and a substantial completion date for Unit 3 approximately 12 months later. SCE&G's 55% portion of this preliminary estimate is approximately $660 million, excluding any owner's cost amounts associated with the delays, which could be $10 million per month for delays beyond the current SCPSC-approved substantial completion dates. This figure is presented in 2007 dollars and would be subject to escalation, which could be material. Further, this figure does not reflect consideration of the liquidated damages provisions of the EPC Contract which would partly mitigate any such delay-related costs. The Consortium's preliminary schedule and the cost estimate information have not been accepted by SCE&G and are under review, and SCE&G cannot predict when a revised schedule and cost estimate will be resolved with the Consortium.

Since receiving the August 2014 preliminary information, SCE&G has worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium now indicates that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. SCE&G is continuing discussions with Consortium executive management in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of December 31, 2014, 101 milestones have been completed. Three of the remaining milestones have not been or will not be completed within their 18-month contingency periods, and it is anticipated that the completion dates for a number of the other remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are now projected to exceed amounts currently approved by the SCPSC of $4.548 billion and $5.755 billion, respectively. As such, in 2015 SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. In addition, that petition is expected to include certain updated owner's costs and other capital costs, including amounts within the Consortium's preliminary cost estimate which may be the subject of dispute. As such, the petition is not expected to reflect the resolution of the above described negotiations. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes (including any ultimate disagreements involving the preliminary cost estimates provided by the Consortium in the third quarter of 2014) through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the current milestone schedule and capital costs schedule approved by the SCPSC in November 2012, SCE&G’s estimated cost would be approximately $500 million for the additional 5% interest being acquired from Santee Cooper. This cost figure could be higher in light of the delays and related costs discussed above.

Nuclear Production Tax Credits

In August 2014, the IRS notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. SCE&G fulfilled the request related to emergency plant staffing in 2012. In addition, SCE&G prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

SCE&G

The EPA issued a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The proposed rule was issued on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the proposed rule, but does not plan to construct new coal-fired units in the near future. In addition, on June 2, 2014, the EPA issued proposed emission guidelines for states to follow in developing plans to address GHG emissions from existing units. These guidelines are to be made final no later than June 1, 2015, and include state-specific rate based goals for carbon dioxide emissions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, thus delaying the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the allowances set by the CSAPR.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in the Company's compliance with MATS. On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at the Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized no later than September 30, 2015. Once the rule becomes effective, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. Based on the proposed rule, the Company expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities.

The CWA Section 316(b) Existing Facilities Rule became effective on October 14, 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On December 19, 2014, the EPA issued a final rule for CCR, which is expected to become effective in 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act. In addition, this rule imposes certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2014, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and is constructing a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2017 and will cost an additional $19.3 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2014, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $35.5 million and are included in regulatory assets.

PSNC Energy

PSNC Energy is responsible for environmental clean-up at five sites in North Carolina on which MGP residuals are present or suspected. Actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $1.0 million, the estimated remaining liability at December 31, 2014. PSNC Energy expects to recover through rates any cost allocable to PSNC Energy arising from the remediation of these sites.

Claims and Litigation

The Company is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on the Company's results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company is obligated under various operating leases for vehicles, office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $12.3 million in 2014, $14.8 million in 2013 and $14.8 million in 2012. Future minimum rental payments under such leases are as follows:

	Millions of dollars
2015	$ 8
2016	5
2017	2
2018	1
2019	2
Thereafter	20
Total	$ 38

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2014, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.7 billion.

Asset Retirement Obligations

The Company recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that results from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2014, the Company has recorded AROs of approximately $201 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $362 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars	2014	2013
Beginning balance	$ 576	$ 561
Liabilities incurred	3	6
Liabilities settled	(6)	(4)
Accretion expense	26	25
Revisions in estimated cash flows	(36)	(12)
Ending balance	$ 563	$ 576

Revisions in estimated cash flows for 2014 primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

The Company received cash distributions from equity-method investees of $7.8 million in 2014, $10.4 million in 2013 and $12.5 million in 2012. The Company made investments in equity-method investees of $5.7 million in 2014, $5.2 million in 2013 and $10.6 million in 2012.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's receivable from this affiliate was $27.8 million at December 31, 2014 and $18.0 million at December 31, 2013. SCE&G's payable to this affiliate was $27.9 million at December 31, 2014 and $18.0 million at December 31, 2013. SCE&G's total purchases from this affiliate were $260.3 million in 2014 and $134.2 million in 2013. SCE&G's total sales to this affiliate were $259.0 million in 2014 and $133.6 million in 2013.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1. The Company records intersegment sales and transfers of electricity and gas based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC.

Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively.

Retail Gas Marketing markets natural gas in Georgia and is regulated as a marketer by the GPSC. Energy Marketing markets natural gas to industrial and large commercial customers and municipalities, primarily in the Southeast.

All Other is comprised of the holding company and its other direct and indirect wholly-owned subsidiaries. One of these subsidiaries operates a FERC-regulated interstate pipeline company and the other subsidiaries conduct nonregulated operations in energy-related and telecommunications industries. None of these subsidiaries met the quantitative thresholds for determining reportable segments during any period reported. See Note 13.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. Marketing segments differ from each other in their respective markets and customer type.

Management uses operating income to measure segment profitability for SCE&G and other regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, the Company does not allocate interest charges, income tax expense or assets other than utility plant to its segments. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Interest income is not reported by segment and is not material. The Company's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of the Company's regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the totals from SCANA or SCE&G that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to asset retirement obligations. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Retail Gas Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2014							
External Revenue	$ 2,622	$ 1,012	$ 515	$ 786	$ 37	$ (21)	$ 4,951
Intersegment Revenue	7	2	—	196	437	(642)	—
Operating Income	768	159	n/a	n/a	27	53	1,007
Interest Expense	19	22	1	—	5	265	312
Depreciation and Amortization	300	72	2	—	24	(14)	384
Income Tax Expense	7	33	16	3	12	177	248
Net Income	n/a	n/a	26	5	(6)	513	538
Segment Assets	10,182	2,487	140	150	1,474	2,419	16,852
Expenditures for Assets	936	200	—	2	52	(98)	1,092
Deferred Tax Assets	11	29	11	9	15	(75)	—
2013							
External Revenue	$ 2,423	$ 942	$ 465	$ 652	$ 40	$ (27)	$ 4,495
Intersegment Revenue	6	1	—	167	416	(590)	—
Operating Income	679	153	n/a	n/a	27	51	910
Interest Expense	19	22	1	—	4	251	297
Depreciation and Amortization	297	70	3	—	26	(18)	378
Income Tax Expense	6	33	15	4	14	151	223
Net Income	n/a	n/a	24	6	(2)	443	471
Segment Assets	9,488	2,340	172	133	1,378	1,653	15,164
Expenditures for Assets	907	140	—	1	31	27	1,106
Deferred Tax Assets	10	27	8	2	14	(61)	—
2012							
External Revenue	$ 2,446	$ 764	$ 413	$ 543	$ 45	$ (35)	$ 4,176
Intersegment Revenue	7	1	—	125	416	(549)	—
Operating Income	668	141	n/a	n/a	22	28	859
Interest Expense	21	23	1	—	3	247	295
Depreciation and Amortization	278	67	3	—	25	(17)	356
Income Tax Expense	7	32	7	3	15	118	182
Net Income	n/a	n/a	11	5	1	403	420
Segment Assets	8,989	2,292	153	122	1,415	1,645	14,616
Expenditures for Assets	999	123	—	1	14	(60)	1,077
Deferred Tax Assets	9	26	10	4	17	(55)	11

13. DISPOSITIONS

In December 2014, SCANA entered into definitive agreements to sell CGT and SCI. CGT is an interstate natural gas pipeline regulated by FERC that transports natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provides fiber optic communications and other services and builds, manages and leases communications towers in several southeastern states, and it was sold to Spirit Communications. These sales closed in the first quarter of 2015. Proceeds from these sales, net of transaction costs, were approximately $625 million, and the estimated pre-tax gain on the sales to be recognized during the first quarter of 2015 is approximately $350 million.

CGT and SCI operate principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI meet accounting criteria for disclosure as a reportable segment. Accordingly, segment disclosures related to them are included within All Other in Note 12. As a result, the Company has determined that the sales of CGT and SCI do not represent a strategic shift that will have a major effect on its operations, and therefore, these sales do not meet the criteria for classification as discontinued operations.

The carrying values of the major classes of assets and liabilities classified as held for sale in the consolidated balance sheet as of December 31, 2014, were as follows:

Millions of dollars	CGT	SCI	Total
Assets Held for Sale			
Utility Plant, Net	$ 288.4	—	$ 288.4
Nonutility Property and Investments, Net	0.6	$ 40.1	40.7
Current Assets	6.5	3.9	10.4
Deferred Debits and Other Assets	0.9	0.2	1.1
Total Assets Held for Sale	$ 296.4	$ 44.2	$ 340.6
Liabilities Held for Sale			
Current Liabilities	$ 3.5	$ 2.2	$ 5.7
Deferred Credits and Other Liabilities	42.9	3.1	46.0
Total Liabilities Held for Sale	$ 46.4	$ 5.3	$ 51.7

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2014					
Total operating revenues	$ 1,590	$ 1,026	$ 1,121	$ 1,214	$ 4,951
Operating income	350	154	269	234	1,007
Net income	193	96	144	105	538
Basic earnings per share	1.37	.68	1.01	.73	3.79
Diluted earnings per share	1.37	.68	1.01	.73	3.79
2013					
Total operating revenues	$ 1,311	$ 1,016	$ 1,051	$ 1,117	$ 4,495
Operating income	293	189	255	173	910
Net income	151	85	131	104	471
Basic earnings per share	1.13	.60	.94	.73	3.40
Diluted earnings per share	1.11	.60	.94	.73	3.39

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCE&G is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, and transportation of natural gas. SCE&G's business is subject to seasonal fluctuations. Generally, sales of electricity are higher during the summer and winter months because of air-conditioning and heating requirements, and sales of natural gas are greater in the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 36 counties in South Carolina and covers approximately 23,000 square miles.

Key Earnings Drivers and Outlook

During 2014, economic growth continued to improve in the southeast. Significant industrial announcements in SCE&G's service territory were made during the year, and announcements made in previous years began to materialize. In addition, the Port of Charleston continues to see increased traffic, with container volume up 12% over 2013. SCE&G also experienced positive residential and commercial customer growth rates and steady unemployment rates for areas it serves.

Over the next five years, key earnings drivers for SCE&G will be additions to utility rate base, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generates electricity and provides for its transmission, distribution and sale to approximately 688,000 customers (as of December 31, 2014) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control growth in costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2014 was 10.25% for non-BLRA rate base, and 11.0% for BLRA-related rate base. To prevent the need for a non-BLRA base rate increase during years of peak nuclear construction, SCE&G has a stated goal of earning a return on equity of 9% or higher. For the year ended December 31, 2014, SCE&G's earned return on equity related to non-BLRA rate base was approximately 10%.

<u>New Nuclear Construction</u>

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and under an agreement signed in January 2014, SCE&G has agreed to acquire an additional 5% ownership in increments coinciding with the commercial operation date of Unit 2 and the first and second anniversaries thereof. The purchase of this additional 5% ownership is expected to be funded by increased cash flows resulting from tax deductibility of depreciation associated with the commercial operation of the New Units.

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. As of December 31, 2014, SCE&G's investment in the New Units totaled $2.7 billion, for which the financing costs on $2.425 billion have been reflected in rates under the BLRA.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018, with an approved 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The intended result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014, SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 was expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

During the third quarter of 2014, the Consortium also provided preliminary cost estimates for Units 2 and 3, principally related to delays for non-firm and non-fixed scopes of work to achieve a late 2018 substantial completion date for Unit 2 and a substantial completion date for Unit 3 approximately 12 months later. SCE&G's 55% portion of this preliminary estimate is approximately $660 million, excluding any owner's cost amounts associated with the delays, which could be $10 million per month for delays beyond the current SCPSC-approved substantial completion dates. This figure is presented in 2007 dollars and would be subject to escalation, which could be material. Further, this figure does not reflect consideration of the liquidated damages provisions of the EPC Contract which would partly mitigate any such delay-related costs. The Consortium's preliminary schedule and the cost estimate information have not been accepted by SCE&G and are under review, and SCE&G cannot predict when a revised schedule and cost estimate will be resolved with the Consortium.

Since receiving the August 2014 preliminary information, SCE&G has worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium now indicates that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. SCE&G is continuing discussions with Consortium executive management in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of December 31, 2014, 101 milestones have been completed. Three of the remaining milestones have not been or will not be completed within their 18-month contingency periods, and it is anticipated that the completion dates for a number of the other remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are now projected to exceed amounts currently approved by the SCPSC of $4.548 billion and $5.755 billion, respectively. As such, in 2015 SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. In addition, that petition is expected to include certain updated owner's costs and other capital costs, including amounts within the Consortium's preliminary cost estimate which may be the subject of dispute. As such, the petition is not expected to reflect the resolution of the above described negotiations. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

In August 2014, the IRS notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

For additional information on these and other matters, see New Nuclear Construction Matters herein and Note 2 and Note 10 to the consolidated financial statements.

Environmental

EPA regulations have a significant impact on Consolidated SCE&G's electric operations. In 2014, several regulations were proposed or became final, including the following:

- A revised carbon standard for new power plants was proposed on January 8, 2014, which requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. This rule effectively prevents construction of new coal-fired plants without carbon capture and sequestration capabilities.

- The Clean Power Plan released on June 2, 2014 would regulate carbon dioxide emissions from existing units. This proposed rule includes state-specific goals for carbon dioxide emissions, as well as guidelines for states to follow in developing SIPs to achieve those goals. Though it may be revised before becoming final in June 2015, the proposal gives states from one to three years from the date of any final rule to issue SIPs. The SIPs will ultimately define the specific compliance methodology that will be applied to existing units in that state.

- The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved in connection with the renewal (every five years) of state-issued NPDES permits. The ELG Rule is expected to be finalized by September 30, 2015.

- A final rule became effective October 14, 2014 that modifies requirements for existing cooling water intake structures. Consolidated SCE&G is conducting studies and is developing or implementing compliance plans for this rule. Congress is also expected to consider further amendments to the CWA, and such legislation may include toxicity-based standards, among other things.

- On November 26, 2014 the EPA announced a proposed tightening of current NAAQS ozone standards from .075 ppm to a range between .065 and .070 ppm, and that it will take comments on a standard as low as .060 ppm. A final rule is expected in October 2015.

- New federal regulations affecting the management and disposal of CCRs were issued on December 19, 2014 and are expected to take effect in 2015. Under these regulations, CCRs will not be regulated as hazardous waste. These regulations do impose certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The above environmental initiatives and similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, Consolidated SCE&G cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on Consolidated SCE&G, if any. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The local distribution operations of SCE&G purchases, transports and sells natural gas to approximately 338,000 retail customers (as of December 31, 2014) in portions of South Carolina. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control growth in costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25%.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact SCE&G’s ability to retain large commercial and industrial customers. In addition, the production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at such levels for the foreseeable future.

RESULTS OF OPERATIONS

Net Income

Net income for Consolidated SCE&G was as follows:

Millions of dollars	2014	Change	2013	Change	2012
Net income	$ 457.7	17.1%	$ 390.8	11.0%	$ 352.0

2014 vs 2013	Net income increased primarily due to the effects of weather, customer growth and base rate increases under the BLRA. Higher electric and gas margins were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.
2013 vs 2012	Net income increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.

Dividends Declared

Consolidated SCE&G's Boards of Directors declared the following dividends on common stock (all of which was held by SCANA):

Declaration Date	Dividend Amount	Quarter Ended	Payment Date
February 19, 2015	$70.7 million	March 31, 2015	April 1, 2015
February 20, 2014	$64.3 million	March 31, 2014	April 1, 2014
April 24, 2014	$64.4 million	June 30, 2014	July 1, 2014
July 31, 2014	$68.5 million	September 30, 2014	October 1, 2014
October 30, 2014	$74.4 million	December 31, 2014	January 1, 2015
February 20, 2013	$64.0 million	March 31, 2013	April 1, 2013
April 25, 2013	$63.8 million	June 30, 2013	July 1, 2013
July 31, 2013	$67.5 million	September 30, 2013	October 1, 2013
October 31, 2013	$61.7 million	December 31, 2013	January 1, 2014

When a dividend payment date falls on a weekend or holiday, the payment is made the following business day.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2014	Change	2013	Change	2012
Operating revenues	$ 2,629.4	8.2%	$ 2,430.5	(0.9)%	$ 2,453.1
Less: Fuel used in electric generation	799.3	6.4%	751.0	(11.0)%	844.2
Purchased power	80.7	87.7%	43.0	53.0 %	28.1
Margin	$ 1,749.4	6.9%	$ 1,636.5	3.5 %	$ 1,580.8

2014 vs 2013	Electric margin increased due to the effects of weather of $43.5 million, base rate increases under the BLRA of $54.1 million and customer growth of $14.7 million. These margin increases were partially offset by $69.0 million of downward adjustments to electric revenues in 2014 pursuant to SCPSC orders related to fuel cost recovery and SCE&G's DSM Programs. In 2013, pursuant to SCPSC orders, electric revenues were adjusted downward by $50.1 million related to fuel cost recovery and the reversal of undercollected amounts related to SCE&G's pilot eWNA program (eWNA was discontinued effective with the first billing cycle of 2014). Such adjustments are fully offset by the recognition within other income of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of SCE&G's storm damage reserve, both of which had been deferred in regulatory accounts. See Note 2 to the consolidated financial statements.
2013 vs 2012	Margin increased primarily due to base rate increases under the BLRA of $54.2 million and higher electric base rates of $67.3 million approved in the December 2012 rate order. Additionally, pursuant to accounting orders of the SCPSC, 2013's electric margin reflects downward adjustments of $50.1 million to revenue. Such adjustments are fully offset by the recognition within other income of gains realized upon the settlement of certain derivative interest rate contracts, which had been deferred as regulatory liabilities. See Note 2 to the consolidated financial statements.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2014	Change	2013	Change	2012
Residential	8,156	7.7%	7,571	—	7,571
Commercial	7,371	2.3%	7,205	(1.2)%	7,291
Industrial	6,234	3.9%	6,000	2.8 %	5,836
Other	600	3.3%	581	(0.9)%	586
Total retail sales	22,361	4.7%	21,357	0.3 %	21,284
Wholesale	958	0.3%	955	(63.2)%	2,595
Total	23,319	4.5%	22,312	(6.6)%	23,879

2014 vs 2013	Retail sales volumes increased primarily due to the effects of weather and customer growth.
2013 vs 2012	Retail sales volume increased primarily due to customer growth and the effects of weather, partially offset by lower average use. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2014	Change	2013	Change	2012
Operating revenues	$ 462.2	11.5%	$ 414.4	16.5%	$ 355.6
Less: Gas purchased for resale	283.1	16.0%	244.1	24.2%	196.6
Margin	$ 179.1	5.2%	$ 170.3	7.1%	$ 159.0

2014 vs 2013	Margin increased primarily due to weather, residential and commercial customer growth of $4.0 million and increased average usage of $2.5 million.
2013 vs 2012	Margin increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012, as well as residential and commercial customer growth.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2014	Change	2013	Change	2012
Residential	14,917	19.2 %	12,515	23.3%	10,153
Commercial	13,936	9.0 %	12,786	9.1%	11,723
Industrial	18,307	(10.3)%	20,411	5.5%	19,341
Transportation gas	4,286	(10.7)%	4,801	2.0%	4,707
Total	51,446	1.8 %	50,513	10.0%	45,924

2014 vs 2013 Residential and commercial sales volumes increased primarily due to the effects of weather and customer growth. Industrial sales volumes decreased due to weather related curtailments and a customer switching to an alternative fuel source. Transportation sales volumes decreased due to weather related curtailments.

2013 vs 2012 Total sales volumes increased primarily due to customer growth, increased industrial usage and the effects of weather.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Other operation and maintenance	$ 575.2	3.4%	$ 556.5	2.8%	$ 541.6
Depreciation and amortization	315.2	0.6%	313.4	6.8%	293.4
Other taxes	207.9	3.8%	200.2	6.3%	188.3

2014 vs 2013 Other operation and maintenance expenses increased primarily due to higher electric operating expenses of $8.9 million, DSM Programs cost amortization of $2.1 million, higher labor expense of $2.4 million which includes incentive compensation and lower pension costs, storm expenses of $1.1 million, and other general expenses of $1.9 million. Depreciation and amortization expense increased due to net plant additions. Other taxes increased primarily due to higher property taxes.

2013 vs 2012 Other operation and maintenance expenses increased by $16.7 million due to incremental expenses associated with the December 2012 SCPSC rate order and by $5.7 million due to higher electric generation, transmission and distribution expenses. These increases were partially offset by lower compensation costs of $10.1 million due to reduced headcount and lower incentive compensation accruals and by other general expenses. Depreciation and amortization expense increased $13.2 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 SCPSC rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes on net property additions.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on Consolidated SCE&G's income statements and balance sheets as follows:

Millions of dollars	2014	Change	2013	Change	2012
Income Statement Impact:					
Employee benefit costs	$ 4.0	(63.6)%	$ 11.0	100.0 %	—
Other expense	0.1	(83.3)%	0.6	50.0 %	$ 0.4
Balance Sheet Impact:					
Increase in capital expenditures	0.3	(95.3)%	6.4	12.3 %	5.7
Component of amount receivable from Summer Station co-owner	0.1	(96.0)%	2.5	13.6 %	2.2
Increase (decrease) in regulatory asset	(3.2)	*	5.5	(63.3)%	15.0
Net periodic benefit cost	$ 1.3	(96.0)%	$ 26.0	11.6 %	$ 23.3

* Greater than 100%

In 2013, pursuant to regulatory orders, SCE&G began recovering current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and began amortizing pension costs previously deferred in regulatory assets over approximately 30 years (for retail electric operations) and approximately 14 years (for gas operations). See further discussion in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were as follow:

Millions of dollars	2014	2013
Retail electric operations	$ 2.0	$ 2.0
Gas operations	1.0	0.2

Other Income (Expense)

Other income (expense) includes the results of certain incidental non-utility activities and AFC. Components of other income (expense), were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Other income	$ 79.8	51.4%	$ 52.7	*	$ 0.4
Other expense	(33.8)	93.1%	(17.5)	(2.2)%	(17.9)
Total	$ 46.0	30.7%	$ 35.2	*	$ (17.5)

* Greater than 100%

2014 vs 2013 — Other income (expense) increased primarily due to the recognition of $64.0 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed, compared to $50.1 million of such gains in 2013. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income. Donations increased $4.6 million, equity partnership losses increased $2.3 million and AFC increased $2.6 million.

2013 vs 2012 — Total other income (expense) increased primarily due to the recognition, pursuant to SCPSC accounting orders, of $50.1 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as regulatory liabilities. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

AFC

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. Consolidated SCE&G includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 6.2% of income before income taxes in 2014, 6.6% in 2013 and 6.3% in 2012, respectively.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2014	Change	2013	Change	2012
Interest on long-term debt, net	$ 217.6	5.2 %	$ 206.8	3.0%	$ 200.7
Other interest expense	10.4	(1.0)%	10.5	7.1%	9.8
Total	$ 228.0	4.9 %	$ 217.3	3.2%	$ 210.5

Interest on long-term debt increased in each year primarily due to increased long-term borrowings.

Income Taxes

Income tax expense increased in 2014 over 2013 and in 2013 over 2012 primarily due to increases in income before taxes. Consolidated SCE&G's effective tax rate has been favorably impacted by equity AFC and certain tax credits.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its contractual cash obligations will be met through internally generated funds and additional short- and long-term borrowings. Consolidated SCE&G expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Consolidated SCE&G's cash requirements arise primarily from its operational needs, funding its construction programs and payment of dividends to SCANA. The ability of Consolidated SCE&G to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental
regulations, will depend upon its ability to attract the necessary financial capital on reasonable terms. Consolidated SCE&G recovers the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and Consolidated SCE&G continues its ongoing construction program, Consolidated SCE&G expects to seek increases in rates. Consolidated SCE&G's future financial position and results of operations will be affected by Consolidated SCE&G's ability to obtain adequate and timely rate and other regulatory relief.

Cash outlays for property additions and construction expenditures, including nuclear fuel, net of AFC were $934 million in 2014. Consolidated SCE&G's current estimates of its capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2015	2016	2017
Consolidated SCE&G - Normal			
Generation	$ 158	$ 123	$ 143
Transmission & Distribution	272	251	217
Other	37	41	27
Gas	54	64	57
Common	9	12	9
Total Consolidated SCE&G - Normal	530	491	453
New Nuclear (including transmission)	957	928	708
Cash Requirements for Construction	1,487	1,419	1,161
Nuclear Fuel	22	145	104
Total Estimated Capital Expenditures	$ 1,509	$ 1,564	$ 1,265

Estimated capital expenditures for Nuclear Fuel in 2016 include approximately $53 million, which is SCE&G's share of nuclear fuel it acquired in 2013. This fuel has been recorded in utility plant and the corresponding liability has been recorded in long-term debt on the consolidated balance sheet.

Consolidated SCE&G's contractual cash obligations as of December 31, 2014 are summarized as follows:

Contractual Cash Obligations	Payments due by period				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term and short-term debt including interest	$ 9,611	$ 941	$ 1,492	$ 374	$ 6,804
Capital leases	14	3	7	3	1
Operating leases	29	6	4	1	18
Purchase obligations	3,285	2,149	1,136	—	—
Other commercial commitments	2,541	480	922	555	584
Total	$ 15,480	$ 3,579	$ 3,561	$ 933	$ 7,407

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at Summer Station. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent of the cost and receiving 55 percent of the output. The estimated $500 million SCE&G expects it will cost to acquire an additional 5% ownership in the New Units is included in other commercial commitments and is further described in New Nuclear Construction Matters.

Purchase obligations includes customary purchase orders under which SCE&G has the option to utilize certain vendors without the obligation to do so. SCE&G may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations for coal and nuclear fuel purchases. SCE&G also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional asset retirement obligations that are not listed in the contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

At December 31, 2014, Consolidated SCE&G had posted $107 million in cash collateral for interest rate derivative contracts.

Financing Limits and Related Matters

Consolidated SCE&G’s issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including the SCPSC and FERC. Financing programs currently utilized by Consolidated SCE&G follow.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

In October 2014, the Consolidated SCE&G's existing five-year committed LOCs were extended by one year. At December 31, 2014 SCE&G and Fuel Company were parties to five-year credit agreements in the amounts of $1.2 billion, (of which $500 million relates to Fuel Company) which expire in October 2019. In addition, at December 31, 2014 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2014, Consolidated SCE&G had no outstanding borrowings under its $1.4 billion facilities, had approximately $709 million in commercial paper borrowings outstanding, was obligated under $.3 million in LOC-supported letters of credit, and had approximately $100 million in cash and temporary investments. Consolidated SCE&G regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance
on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2014 were approximately $404 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2014, Consolidated SCE&G’s long-term debt portfolio has a weighted average maturity of approximately 21 years and bears an average cost of 5.7%. Substantially all of Consolidated SCE&G's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, Consolidated SCE&G rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

SCE&G’s Restated Articles of Incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock, all of which is beneficially owned by SCANA.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2014, approximately $67.7 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12

consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2014, the Bond Ratio was 5.41.

Financing Activities

During 2014, net cash inflows related to financing activities totaled approximately $582 million, primarily associated with the issuance of short and long-term debt and contributions from parent, partially offset by repayment of long-term debt and payment of dividends. For a description of specific financing activities, see Notes 3 and 4 to the consolidated financial statements.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Investing Activities

During 2014, SCE&G paid approximately $95 million to settle interest rate derivative contracts.

Consolidated SCE&G paid approximately $6 million, net, through the third quarter of 2013 to settle interest rate derivative contracts upon the issuance of long-term debt. In addition, during the fourth quarter of 2013, Consolidated SCE&G received approximately $120 million upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt.

For additional information, see Note 4 to the consolidated financial statements.

Major tax incentives included within recent federal legislation resulted in the allowance of 50% bonus depreciation for property placed in service for 2012 and 2013. These incentives, along with certain other deductions, have had a positive impact on the cash flows of Consolidated SCE&G. Similar tax incentives for property placed in service for 2014 were implemented after estimated tax payments for the 2014 tax year had been made. As a result, these excess payments are expected to have a positive impact on the cash flows of Consolidated SCE&G in 2015.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2014, were as follows:

December 31,	**2014**	**2013**	**2012**	**2011**	**2010**
SCE&G	3.77	3.48	3.29	3.13	3.18

ENVIRONMENTAL MATTERS

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, Consolidated SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

For the three years ended December 31, 2014, Consolidated SCE&G's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $51.8 million. During this same period, Consolidated SCE&G expended approximately $31.5 million for the construction and retirement of landfills and ash ponds, net of disposal proceeds. In addition, Consolidated SCE&G made expenditures to operate and maintain environmental control equipment at its fossil plants of $9.1 million in 2014, $9.2 million in 2013 and $10.2 million in 2012, which are included in "Other operation and maintenance" expense, and made expenditures to handle waste ash, net of disposal proceeds, of $1.6 million in 2014, $3.2 million in 2013 and $7.9 million in 2012, which are included in "Fuel used in electric generation." In addition, included within "Other operation and maintenance" expense is an annual amortization of $1.4 million in each of 2014, 2013 and 2012 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for Consolidated SCE&G are $31.9 million for 2015 and $68.6 million for the four-year period 2016-2019. These expenditures are included in Consolidated SCE&G's Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though Consolidated SCE&G cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. Consolidated SCE&G cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact Consolidated SCE&G, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include the impact of possible changes in weather patterns, such as storm frequency and intensity, and the resultant potential damage to Consolidated SCE&G's electric system, as well as impacts on employees and customers and on its supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations in advance of such storms, all in order to allow Consolidated SCE&G to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCE&G, GENCO and Fuel Company are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCE&G, GENCO and Fuel Company	The CFTC to the extent they transact swaps as defined in Dodd-Frank.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions and other matters; the PHMSA as to integrity management requirements for gas distribution pipeline systems; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale for resale, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to the issuance of short-term borrowings, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of Consolidated SCE&G's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Utility Regulation

Consolidated SCE&G's regulated operations record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, Consolidated SCE&G may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of Consolidated SCE&G's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of Consolidated SCE&G's regulatory assets and liabilities.

Consolidated SCE&G's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, Consolidated SCE&G could be required to write down its investment in those assets. Consolidated SCE&G cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect Consolidated SCE&G's results of operations in the period in which they would be recorded. As of December 31, 2014, Consolidated SCE&G's net investments in fossil/hydro and nuclear generation assets were $2.3 billion and $3.4 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, SCE&G records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2014 and 2013, accounts receivable included unbilled revenues of $115.8 million and $111.9 million, respectively, compared to total revenues of $3.1 billion and $2.8 billion for the years 2014 and 2013, respectively.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact SCE&G's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1on an after-tax basis.

Asset Retirement Obligations

Consolidated SCE&G accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from the acquisition, construction, development and normal operation in accordance with applicable accounting guidance. Consolidated SCE&G recognizes obligations at present value in the period in which they are incurred, and capitalizes associated asset retirement costs as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to Consolidated SCE&G's utility operations, their recognition has no significant impact on results of operations. As of December 31, 2014, Consolidated SCE&G has recorded AROs of $201 million for nuclear plant decommissioning (as discussed above) and AROs of $335 million for other conditional obligations related to generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees. SCANA recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. SCANA's net pension cost of $2.6 million ($1.3 million attributable to SCE&G) recorded in 2014 reflects the use of a 5.03% discount rate derived using a cash flow matching technique, and an assumed 8.00% long-term rate of return on plan assets. SCANA believes that these assumptions were, and that the resulting pension cost amount was, reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2014 would have increased SCANA's pension cost by $1.6 million and increased SCANA's pension obligation by $0.8 million. Further, had the assumed long-term rate of return on assets been 7.75%, SCANA's pension cost for 2014 would have increased by $2.1 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

SCANA determines the fair value of a large majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, SCANA evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2014, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.4%, 6.0%, 8.3% and 9.3%, respectively. The 2014 expected long-term rate of return of 8.00% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. SCANA regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2015, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.0%, 5.4%, 8.7% and 8.8%, respectively. For 2015, the expected rate of return is 7.50%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the significance of pension costs and the criticality of the related estimates to SCE&G's financial statements will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

In October 2014 the Society of Actuaries' Retirement Plans Experience Committee published a new RP-2014 mortality table and the related MP-2014 mortality improvement scale, which SCANA adopted effective December 31, 2014. The improvements in life expectancy and the projected rate of continued improvement increased postretirement benefit obligations measured at December 31, 2014, and the net periodic benefit cost to be recognized in 2015. Had SCANA not adopted this new mortality table and mortality improvement scale, SCE&G's net periodic benefit cost to be recognized in 2015 would have been approximately $3.0 million and $0.2 million lower for pension and other postretirement benefit plans, respectively, and the benefit obligations would have been approximately $22.1 million and $2.1 million lower for pension and other postretirement benefit plans, respectively.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. SCANA accounts for the cost of the postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. SCANA used a discount rate of 5.19%, derived using a cash flow matching technique, and recorded a net cost to SCE&G of $13.3 million for 2014. Had the selected discount rate been 4.94% (25 basis points lower than the discount rate referenced above), the expense for 2014 would have been $0.4 million higher and the obligation would have been $0.2 million. Because the plan provisions include "caps" on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

NEW NUCLEAR CONSTRUCTION MATTERS

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station.

SCE&G's current ownership share in the New Units is 55%. As discussed below, under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2014, SCE&G's investment in the New Units totaled $2.7 billion, for which the financing costs on $2.425 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule, including 146 milestones within that schedule, and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC also approved an 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain focus areas of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01, as well as shield building modules, are considered critical path items for both New Units. CA20 was placed on the nuclear island of Unit 2 in May 2014. The delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of Unit 2 during the first half of 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The intended result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014, SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 was expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

During the third quarter of 2014, the Consortium also provided preliminary cost estimates for Units 2 and 3, principally related to delays for non-firm and non-fixed scopes of work to achieve a late 2018 substantial completion date for Unit 2 and a substantial completion date for Unit 3 approximately 12 months later. SCE&G's 55% portion of this preliminary estimate is approximately $660 million, excluding any owner's cost amounts associated with the delays, which could be $10 million per month for delays beyond the current SCPSC-approved substantial completion dates. This figure is presented in 2007 dollars and would be subject to escalation, which could be material. Further, this figure does not reflect consideration of the liquidated damages provisions of the EPC Contract which would partly mitigate any such delay-related costs. The Consortium's preliminary schedule and the cost estimate information have not been accepted by SCE&G and are under review, and SCE&G cannot predict when a revised schedule and cost estimate will be resolved with the Consortium.

Since receiving the August 2014 preliminary information, SCE&G has worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium now indicates that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. SCE&G is continuing discussions with Consortium executive management in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of December 31, 2014, 101 milestones have been completed. Three of the remaining milestones have not been or will not be completed within their 18-month contingency periods, and it is anticipated that the completion dates for a number of the other remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are now projected to exceed amounts currently approved by the SCPSC of $4.548 billion and $5.755 billion, respectively. As such, in 2015 SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. In addition, that petition is expected to include certain updated owner's costs and other capital costs, including amounts within the Consortium's preliminary cost estimate which may be the subject of dispute. As such, the petition is not expected to reflect the resolution of the above described negotiations. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes (including any ultimate disagreements involving the preliminary cost estimates provided by the Consortium in the third quarter of 2014) through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the current milestone schedule and capital costs schedule approved by the SCPSC in November 2012, SCE&G's estimated cost would be approximately $500 million for the additional 5% interest being acquired from Santee Cooper. This cost figure could be higher in light of the delays and related costs discussed above.

Nuclear Production Tax Credits

In August 2014, the IRS notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. SCE&G fulfilled the request related to emergency plant staffing in 2012. In addition, SCE&G prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

OTHER MATTERS

Financial Regulatory Reform

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. Consolidated SCE&G has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. Consolidated SCE&G is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

Off-Balance Sheet Arrangements

Consolidated SCE&G holds insignificant investments in securities and businesses ventures. Consolidated SCE&G does not engage in significant off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

The tables below provide information about long-term debt issued by Consolidated SCE&G which is sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2014 Millions of dollars	Expected Maturity Date 2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	9.9	109.4	9.0	718.6	8.1	3,379.7	4,234.8	4,999.8
Average Fixed Interest Rate (%)	4.54	1.11	4.73	5.95	4.97	5.29	5.29	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	65.2
Average Variable Interest Rate (%)	—	—	—	—	—	0.04	0.04	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	950.0	100.0	—	—	—	67.8	1,117.8	(233.0)
Average Pay Interest Rate (%)	3.83	3.63	—	—	—	3.28	3.78	—
Average Receive Interest Rate (%)	0.26	0.26	—	—	—	0.04	0.24	—

December 31, 2013 Millions of dollars	Expected Maturity Date 2014	2015	2016	2017	2018	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	45.2	9.2	108.6	8.2	717.9	3,086.5	3,975.6	4,356.6
Average Fixed Interest Rate (%)	4.84	4.73	1.11	4.96	5.95	6.62	6.32	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	64.9
Average Variable Interest Rate (%)	—	—	—	—	—	0.11	0.11	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	600.0	650.0	—	—	—	71.4	1,321.4	30.6
Average Pay Interest Rate (%)	3.96	4.16	—	—	—	3.29	4.02	—
Average Receive Interest Rate (%)	0.25	0.25	—	—	—	0.06	0.24	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above tables exclude long-term debt of $3 million at December 31, 2013, which did not have stated interest rates associated with them.

For further discussion of Consolidated SCE&G's long-term debt and interest rate derivatives, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 27, 2015

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2014	2013
Assets		
Utility Plant In Service	$ 10,650	$ 10,378
Accumulated Depreciation and Amortization	(3,667)	(3,499)
Construction Work in Progress	3,302	2,682
Plant to be Retired, Net	169	177
Nuclear Fuel, Net of Accumulated Amortization	329	310
Utility Plant, Net ($675 and $720 related to VIEs)	10,783	10,048
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	67	69
Assets held in trust, net-nuclear decommissioning	113	101
Other investments	2	3
Nonutility Property and Investments, Net	182	173
Current Assets:		
Cash and cash equivalents	100	92
Receivables, net of allowance for uncollectible accounts of $4 and $3	524	486
Receivables-affiliated companies	109	19
Inventories:		
Fuel	130	131
Materials and supplies	129	120
Emission allowances	1	1
Prepayments	154	65
Other current assets	99	15
Total Current Assets ($158 and $147 related to VIEs)	1,246	929
Deferred Debits and Other Assets:		
Pension asset	10	96
Regulatory assets	1,745	1,303
Other	141	151
Total Deferred Debits and Other Assets ($50 and $35 related to VIEs)	1,896	1,550
Total	$ 14,107	$ 12,700

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2014	2013
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,560	$ 2,479
Retained Earnings	2,077	1,896
Accumulated Other Comprehensive Income	(3)	(3)
Total Common Equity	4,634	4,372
Noncontrolling interest	123	117
Total Equity	4,757	4,489
Long-Term Debt, net	4,299	4,007
Total Capitalization	9,056	8,496
Current Liabilities:		
Short-term borrowings	709	251
Current portion of long-term debt	10	48
Accounts payable	294	241
Affiliated payables	180	117
Customer deposits and customer prepayments	61	56
Taxes accrued	170	223
Interest accrued	64	64
Dividends declared	74	62
Derivative financial instruments	208	1
Other	99	71
Total Current Liabilities	1,869	1,134
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,696	1,509
Deferred investment tax credits	28	32
Asset retirement obligations	536	547
Pension and Postretirement benefits	195	173
Regulatory liabilities	610	732
Other	117	77
Total Deferred Credits and Other Liabilities	3,182	3,070
Commitments and Contingencies (Note 10)	—	—
Total	$ 14,107	$ 12,700

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, (Millions of dollars)	2014	2013	2012
Operating Revenues:			
Electric	$ 2,629	$ 2,431	$ 2,453
Gas	462	414	356
Total Operating Revenues	3,091	2,845	2,809
Operating Expenses:			
Fuel used in electric generation	799	751	844
Purchased power	81	43	28
Gas purchased for resale	283	244	197
Other operation and maintenance	575	557	542
Depreciation and amortization	315	313	293
Other taxes	208	200	188
Total Operating Expenses	2,261	2,108	2,092
Operating Income	830	737	717
Other Income (Expense):			
Other income	80	53	—
Other expenses	(34)	(18)	(18)
Interest charges, net of allowance for borrowed funds used during construction of $14, $13 and $11	(228)	(217)	(211)
Allowance for equity funds used during construction	28	25	21
Total Other Expense	(154)	(157)	(208)
Income Before Income Tax Expense	676	580	509
Income Tax Expense	218	189	157
Net Income	458	391	352
Less Net Income Attributable to Noncontrolling Interest	12	11	11
Earnings Available to Common Shareholder	$ 446	$ 380	$ 341
Dividends Declared on Common Stock	$ 272	$ 257	$ 209

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (Millions of dollars)	2014	2013	2012
Net Income	$ 458	$ 391	$ 352
Other Comprehensive Income (Loss), net of tax:			
Deferred costs of employee benefit plans, net of tax $-, $- and $-	—	1	(1)
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax $-, $- and $-	—	—	—
Other Comprehensive Income (Loss)	—	1	(1)
Total Comprehensive Income	458	392	351
Less comprehensive income attributable to noncontrolling interest	(12)	(11)	(11)
Comprehensive income available to common shareholder	$ 446	$ 381	$ 340

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2014	2013	2012
Cash Flows From Operating Activities:			
Net income	$ 458	$ 391	$ 352
Adjustments to reconcile net income to net cash provided from operating activities:			
Losses from equity method investments	5	3	4
Deferred income taxes, net	187	29	116
Depreciation and amortization	318	315	294
Amortization of nuclear fuel	45	57	44
Allowance for equity funds used during construction	(28)	(25)	(21)
Carrying cost recovery	(9)	(3)	—
Changes in certain assets and liabilities:			
Receivables	(39)	(36)	35
Inventories	(52)	35	(60)
Prepayments	(89)	8	6
Regulatory assets	(350)	83	(158)
Other regulatory liabilities	(132)	54	64
Accounts payable	14	5	27
Taxes accrued	(53)	72	1
Pension and other postretirement benefits	106	(186)	69
Derivative financial instruments	207	(65)	64
Other assets	12	27	(154)
Other liabilities	41	88	(9)
Net Cash Provided From Operating Activities	641	852	674
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(934)	(1,003)	(978)
Proceeds from investments and sales of assets (including derivative collateral returned)	275	144	275
Purchase of investments (including derivative collateral posted)	(381)	(116)	(268)
Payments upon interest rate derivative contract settlement	(95)	(49)	—
Proceeds from interest rate derivative contract settlement	—	163	14
Investment in affiliate	(80)	—	—
Net Cash Used For Investing Activities	(1,215)	(861)	(957)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	294	451	513
Repayment of long-term debt	(48)	(251)	(49)
Dividends	(260)	(241)	(202)
Short-term borrowings, net	458	(198)	(63)
Short-term borrowings-affiliate, net	56	(22)	(9)
Contribution from parent	82	311	128
Net Cash Provided From Financing Activities	582	50	318
Net Increase in Cash and Cash Equivalents	8	41	35
Cash and Cash Equivalents, January 1	92	51	16
Cash and Cash Equivalents, December 31	$ 100	$ 92	$ 51
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $14, $13 and $11)	$ 210	$ 200	$ 186
—Income taxes	177	92	105
Noncash Investing and Financing Activities:			
Accrued construction expenditures	151	100	116
Capital lease	5	4	8
Nuclear fuel purchase	—	98	—

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Millions	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Equity
Balance at January 1, 2012	40	$ 2,041	$ 1,627	$ (3)	$ 108	$ 3,773
Earnings available for common shareholder			341		11	352
Deferred cost of employee benefit plans, net of tax $-				(1)		(1)
Total Comprehensive Income (Loss)			341	(1)	11	351
Capital contributions from parent		126			2	128
Cash dividends declared			(202)		(7)	(209)
Balance at December 31, 2012	40	2,167	1,766	(4)	114	4,043
Earnings Available for Common Shareholder			380		11	391
Deferred Cost of Employee Benefit Plans, net of tax $-				1		1
Total Comprehensive Income (Loss)			380	1	11	392
Capital contributions from parent		312			(1)	311
Cash dividends declared			(250)		(7)	(257)
Balance at December 31, 2013	40	2,479	1,896	(3)	117	4,489
Earnings Available for Common Shareholder			446		12	458
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			446	—	12	458
Capital contributions from parent		81			1	82
Cash dividends declared			(265)		(7)	(272)
Balance at December 31, 2014	40	$ 2,560	$ 2,077	$ (3)	$ 123	$ 4,757

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs), and accordingly, the accompanying consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. Accordingly, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's consolidated financial statements. Intercompany balances and transactions between SCE&G, Fuel Company and GENCO have been eliminated in consolidation.

GENCO owns a coal-fired electric generating station with a 605 megawatt net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $472 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. Consolidated SCE&G calculated AFC using average composite rates of 6.5% for 2014, 6.9% for 2013
and 6.3% for 2012. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Consolidated SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were 2.84% in 2014, 2.94% in 2013 and 2.91% in 2012.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2014		2013	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.1 billion	—
Accumulated depreciation	$ 578.3 million	—	$ 566.9 million	—
Construction work in progress	$ 199.3 million	$ 2.7 billion	$ 127.1 million	$ 2.3 billion

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $88.9 million at December 31, 2014 and $75.6 million at December 31, 2013.

Plant to be Retired

SCE&G expects to retire three units that are or were coal-fired by 2020, subject to future developments in environmental regulations, among other matters. The net carrying value of these units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC. The net carrying value of three previously retired units is recorded in regulatory assets within unrecovered plant (see Note 2).

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued to regulatory assets in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the balance sheet (see Note 2). Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2014 and 2013, SCE&G incurred $19.4 million and $18.1 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. SCE&G accrued $1.2 million per month from July 2011 through December 2012 for its portion of the outages in the fall of 2012. Total costs for the 2012 outage were $32.3 million, of which SCE&G was responsible for $21.5 million. In connection with the SCPSC's December 2012 approval of SCE&G's retail electric rates (see Note 2), effective January 1, 2013, SCE&G began to accrue $1.4 million per month for its portion of the nuclear refueling outages that are scheduled to occur from the spring of 2014 through the spring of 2020. Total costs for the 2014 outage were $43.7 million, of which SCE&G was responsible for $29.1 million.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2014, 2013 and 2012) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Consolidated SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Accounts Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Inventory

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas and fuel oil. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC. Emission allowances are included in inventory at average cost. Emission allowances are expensed at weighted average cost as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA. Under a joint consolidated income tax allocation agreement, each SCANA subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or revenues would be recognized by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

Consolidated SCE&G records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

Consolidated SCE&G presents the revenues and expenses of its regulated activities (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

Consolidated SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $115.8 million at December 31, 2014 and $111.9 million at December 31, 2013.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

Customers subject to the PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented an eWNA on a pilot basis for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC. See Note 2.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

New Accounting Matters

In April 2014, the Financial Accounting Standards Board issued new accounting guidance for reporting discontinued operations and disclosures of disposals of components of an entity. Under this new guidance, only those discontinued operations which represent a strategic shift that will have a major effect on an entity's operations and financial results should be reported as discontinued operations in the financial statements. As permitted, Consolidated SCE&G adopted this new guidance for the period ended December 31, 2014.

In May 2014, the Financial Accounting Standards Board issued new accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Consolidated SCE&G will be required to adopt the new guidance in the first quarter of 2017, and early adoption is not permitted. Consolidated SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased. In connection with its annual review of base rates for fuel costs, and by order dated April 30, 2013, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. The order also provided for the accrual of certain debt-related carrying costs on a portion of SCE&G's under-collected balance of base fuel costs, and approved SCE&G's total fuel cost component.

Pursuant to a November 2013 SCPSC accounting order, SCE&G's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

By order dated April 29, 2014, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to increase its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs, which was approved by the SCPSC in March 2014. In addition, pursuant to the April 29, 2014 order, SCE&G's electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs during the period May 1, 2014 through April 30, 2015. See also Note 6.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The SCPSC will consider the impact of this action in future cost of fuel rate proceedings.

In October 2014, the SCPSC initiated its 2015 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 9, 2015. In connection with its January 2015 DSM Programs filing (see Electric-Base Rates herein), SCE&G notified the SCPSC that it anticipates proposing an adjustment to SCE&G's cost of fuel that, if approved, will result in an overall decrease to its base fuel costs beginning with the first billing cycle of May 2015.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term borrowing rate, and $5.8 million and $2.9 million of such carrying costs were accrued within other income during 2014 and 2013, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates, a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. In February 2013, the SCPSC denied the SCEUC's petition for rehearing and the denial was not appealed.

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective

December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G previously identified six coal-fired units that it has subsequently retired or intends to retire by 2020, subject to future developments in environmental regulations, among other matters. Three of these units had been retired by December 31, 2013, and their net carrying value is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and net lost revenues associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC approved recovery of the following amounts pursuant to annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million

Other activity related to SCE&G’s DSM Programs is as follows:

- In May 2013, the SCPSC ordered the deferral of one-half of the net lost revenues and provided for their recovery over a 12-month period beginning with the first billing cycle in May 2014.

- In April 2014, the SCPSC approved SCE&G's request to (1) recover one-half of the balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2014 and to recover the remaining balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2015, (2) utilize approximately $17.8 million of gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of the net lost revenues component of SCE&G's DSM Program rider, and (3) apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets resulting from the May 2013 order previously described.

- In addition, in April 2014 the SCPSC, upon recommendation of the ORS, reduced by 25%, or $6.6 million, the amount of net lost revenues SCE&G expects to experience over the 12-month period beginning with the first billing cycle of May 2014, and ordered that the $6.6 million be applied to decrease the amount of program costs deferred for recovery. Actual net lost revenues not collected in the current DSM Programs rate rider are subject to true up in the following program year.

- In January 2015, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would, among other things, allow recovery of $33.0 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. In December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million
2012	2.3%	$52.1 million

Gas

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action		Amount	
2014	0.6%	Decrease	$	2.6 million
2013	No change			
2012	2.1%	Increase	$	7.5 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2014 and 2013 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each review period were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, Consolidated SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	December 31, 2014	December 31, 2013
Regulatory Assets:		
Accumulated deferred income taxes	$ 278	$ 256
Under-collections-electric fuel adjustment clause	20	18
Environmental remediation costs	36	37
AROs and related funding	347	350
Franchise agreements	26	31
Deferred employee benefit plan costs	310	215
Planned major maintenance	2	—
Deferred losses on interest rate derivatives	453	124
Deferred pollution control costs	36	37
Unrecovered plant	137	145
DSM Programs	56	51
Other	44	39
Total Regulatory Assets	$ 1,745	$ 1,303
Regulatory Liabilities:		
Accumulated deferred income taxes	$ 17	$ 19
Asset removal costs	505	495
Storm damage reserve	6	27
Deferred gains on interest rate derivatives	82	181
Planned major maintenance	—	10
Total Regulatory Liabilities	$ 610	$ 732

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recovered over periods of up to approximately 25 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on an SCPSC order, SCE&G is recovering these amounts through cost of service rates through 2020.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil-fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects and accrues $18.4 million annually for fossil-fueled turbine/generation equipment maintenance, and collects and accrues $17.2 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2038. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense over periods up to approximately 50 years except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC. Also, in 2014, as discussed above at Rate Matters - Electric - Cost of Fuel and Rate Matters - Electric - Base Rates, certain of these deferred amounts were applied to offset under-collected fuel balances and unrecorded net lost revenues related to DSM Programs.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at certain coal-fired generating plants pursuant to specific regulatory orders. Such costs are being recovered through utility rates through 2045.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2014 SCPSC order, deferred costs are currently being recovered over approximately ten years through an approved rate rider. See Rate Matters - Electric - Base Rates above for details regarding the 2014 filing with the SCPSC regarding recovery of these deferred costs.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the non-legal obligation to remove assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely. In 2014, $16.8 million of the reserve was applied to offset incremental storm damage costs. Also, as discussed above at Rate Matters - Electric - Base Rates, in April 2014 $5.0 million of the reserve was applied to offset unrecovered net lost revenues related to DSM Programs.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2014 and 2013. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2014 and 2013.

SCE&G's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2014 and 2013, retained earnings of approximately $67.7 million and $63.1 million, respectively, were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

Dollars in millions	Maturity	2014 Balance	2014 Rate	2013 Balance	2013 Rate
First Mortgage Bonds (secured)	2018 - 2064	$ 3,840	5.56%	$ 3,540	5.60%
GENCO Notes (secured)	2015 - 2024	227	5.90%	233	5.89%
Industrial and Pollution Control Bonds (a)	2028 - 2038	122	3.51%	158	3.83%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other	2015 - 2027	14	2.63%	16	2.26%
Total debt		4,303		4,047	
Current maturities of long-term debt		(10)		(48)	
Unamortized premium		6		8	
Total long-term debt, net		$ 4,299		$ 4,007	

(a) Includes variable rate debt of $67.8 million at December 31, 2014 (rate of 0.04%) and 2013 (rate of 0.11%), which are hedged by fixed swaps.

The annual amounts of long-term debt maturities for the next five years are summarized as follows:

Year	Millions of dollars
2015	$ 10
2016	109
2017	9
2018	719
2019	8

Substantially all of SCE&G's and GENCO's electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2014, the Bond Ratio was 5.41.

Lines of Credit and Short-Term Borrowings

At December 31, 2014 and 2013, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars		2014		2013
Lines of credit:				
Total committed long-term	$	1,400	$	1,400
Outstanding commercial paper (270 or fewer days)	$	709	$	251
Weighted average interest rate		0.52%		0.27%
Letters of credit supported by an LOC	$	0.3	$	0.3
Available	$	691	$	1,149

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company). In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In October 2014, the term of the five-year agreements was extended by one year, such that they expire in October 2019. The three-year agreement expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N. A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1.4 billion credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9% and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. Consolidated SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G pays fees to the banks as compensation for maintaining committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2014 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $83 million and money pool investments due from an affiliate of $80 million. At December 31, 2013 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $27.3 million. On the consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	2014	2013	2012
Current taxes:			
Federal	$ 39	$ 146	$ 91
State	(6)	13	8
Total current taxes	33	159	99
Deferred taxes, net:			
Federal	157	25	62
State	32	9	12
Total deferred taxes	189	34	74
Investment tax credits:			
Amortization of amounts deferred—state	(1)	(1)	(13)
Amortization of amounts deferred—federal	(3)	(3)	(3)
Total investment tax credits	(4)	(4)	(16)
Total income tax expense	$ 218	$ 189	$ 157

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2014	2013	2012
Net income	$ 446	$ 380	$ 341
Income tax expense	218	189	157
Noncontrolling interest	12	11	11
Total pre-tax income	$ 676	$ 580	$ 509
Income taxes on above at statutory federal income tax rate	$ 237	$ 203	$ 178
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	21	18	17
State investment tax credits (less federal income tax effect)	(5)	(5)	(13)
Allowance for equity funds used during construction	(10)	(9)	(7)
Amortization of federal investment tax credits	(3)	(3)	(3)
Section 41 tax credits	(3)	—	—
Section 45 tax credits	(9)	(5)	(5)
Domestic production activities deduction	(7)	(11)	(9)
Other differences, net	(3)	1	(1)
Total income tax expense	$ 218	$ 189	$ 157

The tax effects of significant temporary differences comprising Consolidated SCE&G's net deferred tax liability are as follows:

Millions of dollars	2014	2013
Deferred tax assets:		
Nondeductible accruals	$ 47	$ 17
Asset retirement obligation, including nuclear decommissioning	205	209
Unamortized investment tax credits	17	19
Regulatory liability, net gain on interest rate derivative contracts settlement	—	27
Other	6	11
Total deferred tax assets	275	283
Deferred tax liabilities:		
Property, plant and equipment	$ 1,623	$ 1,494
Regulatory asset, asset retirement obligation	115	114
Deferred employee benefit plan costs	91	54
Deferred fuel costs	27	26
Regulatory asset, unrecovered plant	53	55
Regulatory asset, net loss on interest rate derivative contracts settlement	21	—
Demand side management costs	21	21
Prepayments	25	23
Other	23	18
Total deferred tax liabilities	1,999	1,805
Net deferred tax liability	$ 1,724	$ 1,522

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA and files various applicable state and local income tax returns. The IRS has completed examinations of SCANA's federal returns through 2004, and SCANA's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2012. With few exceptions, Consolidated SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	2014	2013	2012
Unrecognized tax benefits, January 1	$ 3	—	$ 38
Gross increases-uncertain tax positions in prior period	—	—	—
Gross decreases-uncertain tax positions in prior period	—	—	(38)
Gross increases-current period uncertain tax positions	13	$ 3	—
Settlements	—	—	—
Lapse of statute of limitations	—	—	—
Unrecognized tax benefits, December 31	$ 16	$ 3	$ —

In connection with the change in method of tax accounting for certain repair costs in prior years, the Company had previously recorded an unrecognized tax benefit. During the first quarter of 2012, the publication of new administrative guidance from the IRS allowed Consolidated SCE&G to recognize this benefit. Since this change was primarily a temporary difference, the recognition of this benefit did not have a significant effect on the Consolidated SCE&G's effective tax rate.

During 2013 and 2014, Consolidated SCE&G amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, Consolidated SCE&G recorded an unrecognized tax benefit of $16 million. If recognized, $13 million of the tax benefit would affect Consolidated SCE&G's effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $2 million within the next 12 months. It is also reasonably possible that this tax benefit may decrease by $7 million within the next 12 months. No other material changes in the status of the Consolidated SCE&G's tax positions have occurred through December 31, 2014.

As of December 31, 2014, prepayments primarily relates to the late 2014 extension of the 50% bonus depreciation deduction.

Consolidated SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit in 2012, during 2012 Consolidated SCE&G reversed $2 million of interest expense which had been accrued during 2011. Consolidated SCE&G has not recorded interest expense or penalties associated with uncertain tax positions in 2013 or 2014.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated SCE&G recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. Consolidated SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by Consolidated SCE&G. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including Consolidated SCE&G. The Risk Management Committee, which is comprised of certain officers, including Consolidated SCE&G's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Consolidated SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, Consolidated SCE&G may use treasury rate lock or forward starting swap agreements. Pursuant to regulatory orders issued in 2013, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders issued in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel balances in April 2014. The SCPSC also approved SCE&G's request to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G's DSM Program rider and apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

Consolidated SCE&G was a party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $36.4 million and $36.4 million at December 31, 2014 and 2013, respectively. Consolidated SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.1 billion and $1.3 billion at December 31, 2014 and 2013, respectively.

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments	Asset Derivatives		Liability Derivatives	
Millions of dollars	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
As of December 31, 2014				
Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$ 1
			Other deferred credits and other liabilities	8
Total				$ 9
Not designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$ 207
			Other deferred credits and other liabilities	17
Total				$ 224
As of December 31, 2013				
Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$ 1
Total				$ 1
Not designated as hedging instruments				
Interest rate contracts	Other current assets	$ 13	Derivative financial instruments	$ 1
	Other deferred debits and other assets	19		
Total		$ 32		$ 1

The effect of derivative instruments on the consolidated statements of income is as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Deferred in Regulatory Accounts (Effective Portion)	Gain (Loss) Reclassified from Deferred Accounts into Income (Effective Portion)	
Millions of dollars		**Location**	**Amount**
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)
Year Ended December 31, 2013			
Interest rate contracts	$ 106	Interest expense	$ (3)
Year Ended December 31, 2012			
Interest rate contracts	$ 84	Interest expense	$ (3)

As of December 31, 2014, Consolidated SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.3 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gains (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments	Loss Recognized in Income	Year Ended December 31,		
Millions of dollars	Location	2014	2013	2012
Commodity contracts	Gas purchased for resale	—	—	$ (1)

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income	
		Location	Amount
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64
Year Ended December 31, 2013			
Interest rate contracts	39	Other income	50
Year Ended December 31, 2012			
Interest rate contracts	—	Other income	—

The gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2014, Consolidated SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $5.2 million as an increase to other income.

Credit Risk Considerations

Consolidated SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, Consolidated SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. Consolidated SCE&G uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with Consolidated SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of Consolidated SCE&G’s derivative instruments contain contingent provisions that require Consolidated SCE&G to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2014 and 2013, Consolidated SCE&G had posted $107.1 million and $1.5 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Other Current Assets on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2014 and 2013, Consolidated SCE&G would have been required to post an additional $125.9 million and $- million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2014 and 2013, are $233.0 million and $1.0 million, respectively.

In addition, as of December 31, 2014 and December 31, 2013, Consolidated SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2014 and December 31, 2013, Consolidated SCE&G could request $- million and $31.7 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2014 and December 31, 2013 is $- million and $31.7 million, respectively.

Information related to Consolidated SCE&G's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2014						
Interest rate	—	—	—	—	—	—
As of December 31, 2013						
Interest rate	$ 32	—	$ 32	$ (1)	—	$ 31

Balance sheet location	Other current assets	$ 13
	Other deferred debits and other assets	19
	Total	$ 32

Offsetting Derivative Liabilities

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2014						
Interest rate	$ 233	—	$ 233	—	$ (107)	$ 126

Balance sheet location	Derivative financial instruments	$ 208
	Other deferred credits and other liabilities	25
	Total	$ 233

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Posted	Net Amount
As of December 31, 2013						
Interest rate	$ 2	—	$ 2	$ (1)	$ (1)	$ —

Balance sheet location	Derivative financial instruments	$ 2
	Total	$ 2

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Consolidated SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value Level 2 measurements were as follows:

Millions of dollars	**As of December 31, 2014** **Level 2**	**As of December 31, 2013** **Level 2**
Assets-Interest rate contracts	—	$ 32
Liabilities-Interest rate contracts	$ 233	2

There were no Level 1 or Level 3 fair value measurements for either period presented and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2014 and December 31, 2013 were as follows:

	As of December 31, 2014		As of December 31, 2013	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 4,308.6	$ 5,070.9	$ 4,054.9	$ 4,433.0

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees hired before January 1, 2014. Benefits are no longer offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost. Employees hired after December 31, 2010 are responsible for the full costs of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects Consolidated SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumptions based on Consolidated SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2014**	**2013**	**2014**	**2013**
Benefit obligation, January 1	$ 695.7	$ 788.4	$ 181.7	$ 206.0
Service cost	16.0	17.6	3.6	4.6
Interest cost	34.1	32.6	9.4	8.7
Plan participants' contributions	—	—	1.8	2.0
Actuarial (gain) loss	82.7	(70.7)	18.6	(27.3)
Benefits paid	(54.8)	(50.6)	(9.6)	(9.3)
Curtailment	—	(21.6)	—	—
Amounts funded to parent	—	—	(1.4)	(3.0)
Benefit obligation, December 31	$ 773.7	$ 695.7	$ 204.1	$ 181.7

The accumulated benefit obligation for pension benefits was $747.6 million at the end of 2014 and $673.2 million at the end of 2013. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

Pension Benefits		Other Postretirement Benefits	
2014	**2013**	**2014**	**2013**

Annual discount rate used to determine benefit obligation	4.20%	5.03%	4.30%	5.19%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.75%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.9 million at December 31, 2014 and by $1.0 million at December 31, 2013. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.8 million at December 31, 2014 and by $0.9 million at December 31, 2013.

Funded Status

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2014**	**2013**	**2014**	**2013**
Fair value of plan assets	$ 783.6	$ 792.1	—	—
Benefit obligation	773.7	695.7	$ 204.1	$ 181.7
Funded status	$ 9.9	$ 96.4	$ (204.1)	$ (181.7)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2014**	**2013**	**2014**	**2013**
Current liability	—	—	$ (8.5)	$ (7.8)
Noncurrent asset	$ 9.9	$ 96.4	—	—
Noncurrent liability	—	—	(195.6)	(173.9)

Amounts recognized in accumulated other comprehensive loss (a component of common equity) as of December 31, 2014 and 2013 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2014	2013	2014	2013
Net actuarial loss	$ 1.9	$ 1.8	$ 1.0	$ 0.6
Prior service cost	0.1	0.2	—	—
Total	$ 2.0	$ 2.0	$ 1.0	$ 0.6

Amounts recognized in regulatory assets as of December 31, 2014 and 2013 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2014	2013	2014	2013
Net actuarial loss	$ 191.9	$ 107.7	$ 35.9	$ 20.1
Prior service cost	8.3	11.1	0.5	0.7
Total	$ 200.2	$ 118.8	$ 36.4	$ 20.8

In connection with the joint ownership of Summer Station, as of December 31, 2014 and 2013, SCE&G recorded within deferred debits $17.8 million and $14.1 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2014 and 2013, SCE&G also recorded within deferred debits $15.1 million and $12.6 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2014	2013
Fair value of plan assets, January 1	$ 792.1	$ 732.0
Actual return on plan assets	46.3	110.7
Benefits paid	(54.8)	(50.6)
Fair value of plan assets, December 31	$ 783.6	$ 792.1

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan is closed to new entrants effective January 1, 2014, and benefit accruals will cease effective January 1, 2024. In addition, during 2013, SCANA adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs in connection with the amendments to the plan.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2014 and 2013 and the target allocation for 2015 are as follows:

	Percentage of Plan Assets		
	Target Allocation	At December 31,	
Asset Category	**2015**	**2014**	**2013**
Equity Securities	58%	57%	59%
Fixed Income	33%	34%	32%
Hedge Funds	9%	9%	9%

For 2015, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes an asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy adopted for 2013.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2014 and 2013, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using						
Millions of dollars	**Total**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**
	December 31, 2014			*December 31, 2013*			
Common stock	—	—	—	$ 302	$ 302	—	—
Preferred stock	—	—	—	1	1	—	—
Mutual funds	$ 566	$ 566	—	278	18	$ 260	—
Short-term investment vehicles	18	18	—	18	—	18	—
US Treasury securities	6	6	—	30	—	30	—
Corporate debt securities	78	78	—	48	—	48	—
Loans secured by mortgages	—	—	—	11	—	11	—
Municipals	14	14	—	3	—	3	—
Limited partnerships	29	29	—	32	1	31	—
Multi-strategy hedge funds	73	—	$ 73	69	—	—	$ 69
	$ 784	$ 711	$ 73	$ 792	$ 322	$ 401	$ 69

At December 31, 2014, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2014 or 2013.

The pension plan values common stock, preferred stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	**2014**	**2013**
Beginning Balance	$ 69	$ 64
Unrealized gains included in changes in net assets	4	5
Purchases, issuances, and settlements	—	—
Ending Balance	$ 73	$ 69

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from SCE&G's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	**Pension Benefits**	**Other Postretirement Benefits**
2015	$ 63.4	$ 9.1
2016	64.5	9.8
2017	65.6	10.4
2018	66.1	10.9
2019	65.1	11.5
2020 - 2024	338.4	64.6

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Service cost	$ 16.0	$ 17.6	$ 15.7	$ 3.6	$ 4.6	$ 3.7
Interest cost	34.1	32.6	36.4	9.4	8.7	9.4
Expected return on assets	(56.3)	(51.9)	(50.4)	n/a	n/a	n/a
Prior service cost amortization	3.5	5.0	6.0	0.3	0.6	0.7
Amortization of actuarial losses	4.0	14.3	15.6	—	2.6	1.1
Curtailment	—	8.4	—	—	—	—
Net periodic benefit cost	$ 1.3	$ 26.0	$ 23.3	$ 13.3	$ 16.5	$ 14.9

In connection with regulatory orders, in 2013 SCE&G began recovering current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). SCE&G is amortizing previously deferred pension costs as further described in Note 2.

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2014	2013	2012	2014	2013	2012
Current year actuarial (gain) loss	$ 0.2	$ (0.8)	$ 0.4	$ 0.4	$ (0.4)	$ 0.7
Amortization of actuarial losses	(0.1)	(0.1)	(0.1)	—	(0.1)	—
Amortization of prior service cost	(0.1)	—	(0.1)	—	—	(0.1)
Total recognized in OCI	$ —	$ (0.9)	$ 0.2	$ 0.4	$ (0.5)	$ 0.6

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2014	2013	2012	2014	2013	2012
Current year actuarial (gain) loss	$ 87.7	$ (137.1)	$ 37.9	$ 15.8	$ (24.4)	$ 25.7
Amortization of actuarial losses	(3.5)	(12.7)	(14.0)	—	(2.2)	(1.0)
Amortization of prior service cost	(2.8)	(4.5)	(5.7)	(0.2)	(0.5)	(0.7)
Prior service cost (credit)	—	(7.7)	—	—	—	—
Amortization of transition obligation	—	—	—	—	(0.1)	(0.2)
Total recognized in regulatory assets	$ 81.4	$ (162.0)	$ 18.2	$ 15.6	$ (27.2)	$ 23.8

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Discount rate	5.03%	4.10%/5.07%	5.25%	5.19%	4.19%	5.35%
Expected return on plan assets	8.00%	8.00%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.75%/3.00%	4.00%	3.75%	3.75%	4.00%
Health care cost trend rate	n/a	n/a	n/a	7.40%	7.80%	8.20%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2015 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 10.6	$ 1.6
Prior service cost	3.1	0.2
Total	$ 13.7	$ 1.8

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

Stock Purchase Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan were $20.7 million in 2014, $18.7 million in 2013 and $17.7 million in 2012 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the LTECP which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

Liability Awards

The 2012-2014, 2013-2015, and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. In each performance cycle, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to exceptions for retirement, death, disability or change in control. The remaining 80% of the award was granted in performance shares, which are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to exceptions for retirement, death or disability. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in "GAAP-adjusted net earnings per share from operations" (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2012-2014 performance cycle were paid in cash at SCANA's discretion in February 2015. Cash-settled liabilities related to the performance cycles were paid totaling approximately $1.9 million in 2014, $3.2 million in 2013 and $8.7 million in 2012.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling approximately $12.6 million in 2014, $5.5 million in 2013 and $9.5 million in 2012. Fair value adjustments resulted in capitalized compensation costs of $0.6 million in 2014, $0.5 million in 2013 and $2.1 million in 2012.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Consolidated SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station.

SCE&G's current ownership share in the New Units is 55%. As discussed below, under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2014, SCE&G's investment in the New Units totaled $2.7 billion, for which the financing costs on $2.425 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule, including 146 milestones within that schedule, and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In December 2012, the SCPSC denied separate petitions filed by two parties requesting reconsideration of its order. On October 22, 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC also approved an 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain focus areas of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01, as well as shield building modules, are considered critical path items for both New Units. CA20 was placed on the nuclear island of Unit 2 in May 2014.

The delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of Unit 2 during the first half of 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The intended result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014, SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 was expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

During the third quarter of 2014, the Consortium also provided preliminary cost estimates for Units 2 and 3, principally related to delays for non-firm and non-fixed scopes of work to achieve a late 2018 substantial completion date for Unit 2 and a substantial completion date for Unit 3 approximately 12 months later. SCE&G's 55% portion of this preliminary estimate is approximately $660 million, excluding any owner's cost amounts associated with the delays, which could be $10 million per month for delays beyond the current SCPSC-approved substantial completion dates. This figure is presented in 2007 dollars and would be subject to escalation, which could be material. Further, this figure does not reflect consideration of the liquidated damages provisions of the EPC Contract which would partly mitigate any such delay-related costs. The Consortium's preliminary schedule and the cost estimate information have not been accepted by SCE&G and are under review, and SCE&G cannot predict when a revised schedule and cost estimate will be resolved with the Consortium.

Since receiving the August 2014 preliminary information, SCE&G has worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium now indicates that the substantial completion date of Unit 2 is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. SCE&G is continuing discussions with Consortium executive management in order to identify potential mitigation strategies to possibly accelerate the substantial completion date of Unit 2 to a time earlier in the first half of 2019 or to the end of 2018, with Unit 3 following approximately 12 months later.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of December 31, 2014, 101 milestones have been completed. Three of the remaining milestones have not been or will not be completed within their 18-month contingency periods, and it is anticipated that the completion dates for a number of the other remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are now projected to exceed amounts currently approved by the SCPSC of $4.548 billion and $5.755 billion, respectively. As such, in 2015 SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. In addition, that petition is expected to include certain updated owner's costs and other capital costs, including amounts within the Consortium's preliminary cost estimate which may be the subject of dispute. As such, the petition is not expected to reflect the resolution of the above described negotiations. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes (including any ultimate disagreements involving the preliminary cost estimates provided by the Consortium in the third quarter of 2014) through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the current milestone schedule and capital costs schedule approved by the SCPSC in November 2012, SCE&G’s estimated cost would be approximately $500 million for the additional 5% interest being acquired from Santee Cooper. This cost figure could be higher in light of the delays and related costs discussed above.

Nuclear Production Tax Credits

In August 2014, the IRS notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. SCE&G fulfilled the request related to emergency plant staffing in 2012. In addition, SCE&G prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, Consolidated SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

The EPA issued a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The proposed rule was issued on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the proposed rule, but does not plan to construct new coal-fired units in the near future. In addition, on June 2, 2014, the EPA issued proposed emission guidelines for states to follow in developing plans to address GHG emissions from existing units. These guidelines are to be made final no later than June 1, 2015, and include state-specific rate based goals for carbon dioxide emissions.

From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, thus delaying the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the allowances set by the CSAPR.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and SCE&G and GENCO's evaluation of the rule is ongoing. SCE&G's decision to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in SCE&G's compliance with MATS. On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at the Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized no later than September 30, 2015. Once the rule becomes effective, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. Based on the proposed rule, Consolidated SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities.

The CWA Section 316(b) Existing Facilities Rule became effective on October 14, 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On December 19, 2014, the EPA issued a final rule for CCR, which is expected to become effective in 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act. In addition, this rule imposes certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2014, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and is constructing a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2017 and will cost an additional $19.3 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2014, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $35.5 million and are included in regulatory assets.

Claims and Litigation

Consolidated SCE&G is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on Consolidated SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

Consolidated SCE&G is obligated under various operating leases for vehicles, office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $12.1 million in 2014, $13.6 million in 2013 and $9.6 million in 2012. Future minimum rental payments under such leases are as follows:

	Millions of dollars
2015	$ 6
2016	3
2017	1
2018	—
2019	1
Thereafter	18
Total	$ 29

Asset Retirement Obligations

Consolidated SCE&G recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to Consolidated SCE&G's regulated utility operations. As of December 31, 2014, Consolidated SCE&G has recorded AROs of approximately $201 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $335 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars	2014	2013
Beginning balance	$ 547	$ 535
Liabilities incurred	3	5
Liabilities settled	(6)	(4)
Accretion expense	25	24
Revisions in estimated cash flows	(33)	(13)
Ending Balance	$ 536	$ 547

Revisions in estimated cash flows for 2014 primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

CGT transports natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. Such purchases totaled approximately $30.0 million in 2014, $33.3 million in 2013 and $35.9 million in 2012. SCE&G had approximately $3.3 million and $3.3 million payable to CGT for transportation services at December 31, 2014 and December 31, 2013, respectively. SCE&G had approximately $1.2 million and $1.3 million receivable from CGT for transportation services at December 31, 2014 and December 31, 2013, respectively.

SCE&G purchases natural gas and related pipeline capacity from SEMI to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $195.7 million in 2014, $166.9 million in 2013 and $125.5 million in 2012. SCE&G’s payables to SEMI for such purposes were $12.6 million and $12.5 million as of December 31, 2014 and 2013, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC which is involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G’s receivable from this affiliate was $27.8 million at December 31, 2014 and $18.0 million at December 31, 2013. SCE&G’s payable to this affiliate was $27.9 million at December 31, 2014 and $18.0 million at December 31, 2013. SCE&G’s total purchases from this affiliate were $260.3 million in 2014 and $134.2 million in 2013. SCE&G’s total sales to this affiliate were $259.0 million in 2014 and $133.6 million in 2013.

SCANA Services provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems services, telecommunications services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, general administrative services and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services totaled $292.2 million in 2014, $285.6 million in 2013 and $305.6 million in 2012. Consolidated SCE&G's payables to SCANA Services for these services were $47.3 million and $49.1 million at December 31, 2014 and 2013, respectively.

Borrowings from and investments in an affiliated money pool are described in Note 4.

12. SEGMENT OF BUSINESS INFORMATION

Consolidated SCE&G’s reportable segments follow the same accounting policies as those described in Note 1.

Electric Operations primarily generates, transmits, and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution purchases and sells natural gas, primarily at retail, and is regulated by the SCPSC.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	768	62	—	830
Interest Expense	19	—	$ 209	228
Depreciation and Amortization	300	27	(12)	315
Segment Assets	10,182	721	3,204	14,107
Expenditures for Assets	936	55	(57)	934
Deferred Tax Assets	11	n/a	(11)	—
2013				
External Revenue	$ 2,431	$ 414	—	$ 2,845
Operating Income	679	58	—	737
Interest Expense	19	—	$ 198	217
Depreciation and Amortization	294	26	(7)	313
Segment Assets	9,488	686	2,526	12,700
Expenditures for Assets	907	45	51	1,003
Deferred Tax Assets	10	n/a	(10)	—
2012				
External Revenue	$ 2,453	$ 356	—	$ 2,809
Operating Income	668	49	—	717
Interest Expense	21	—	$ 190	211
Depreciation and Amortization	278	25	(10)	293
Segment Assets	8,989	659	2,456	12,104
Expenditures for Assets	999	56	(77)	978
Deferred Tax Assets	9	n/a	(9)	—

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, Consolidated SCE&G does not allocate interest charges, income tax expense, earnings available to common shareholder or assets other than utility plant to its segments. Intersegment revenue and interest income were not significant. Consolidated SCE&G's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to asset retirement obligations, and totals not allocated to other segments.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2014					
Total operating revenues	$ 859	$ 698	$ 812	$ 722	$ 3,091
Operating income	239	145	272	174	830
Net Income	126	99	157	76	458
Earnings Available to Common Shareholder	123	96	154	73	446
2013					
Total operating revenues	$ 728	$ 696	$ 776	$ 645	$ 2,845
Operating income	191	180	255	111	737
Net Income	92	88	139	72	391
Earnings Available to Common Shareholder	89	85	136	70	380

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2014, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCANA's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2014, SCANA's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2014, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCANA's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2014. There has been no change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2014 that has materially affected or is reasonably likely to materially affect SCANA's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA's internal control system was designed by or under the supervision of SCANA's management, including its CEO and CFO, to provide reasonable assurance to SCANA's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA's management assessed the effectiveness of SCANA's internal control over financial reporting as of December 31, 2014. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA's management believes that, as of December 31, 2014, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on SCANA's internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2014, of the Company and our report dated February 27, 2015, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 27, 2015

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2014, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2014, SCE&G's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2014, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCE&G's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2014. There has been no change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2014 that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G's internal control system was designed by or under the supervision of SCE&G's management, including its CEO and CFO, to provide reasonable assurance to SCE&G's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G's management assessed the effectiveness of SCE&G's internal control over financial reporting as of December 31, 2014. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).* Based on this assessment, SCE&G's management believes that, as of December 31, 2014, internal control over financial reporting is effective based on those criteria.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 23. The other information required by Item 10 is incorporated herein by reference to the captions "INFORMATION ABOUT EXPERIENCE AND QUALIFICATION OF DIRECTORS AND NOMINEES," "NOMINEES FOR DIRECTORS," "CONTINUING DIRECTORS," "BOARD MEETINGS-COMMITTEES OF THE BOARD", "GOVERNANCE INFORMATION-SCANA's Code of Conduct & Ethics" and "OTHER INFORMATION-Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2015 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by Item 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Discussion and Analysis," Compensation Committee Report," "Summary Compensation Table," "2014 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2014 Fiscal Year-End," "2014 Option Exercises and Stock Vested," "Pension Benefits," "2014 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2015 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: Information required by Item 12 is incorporated herein by reference to the caption "SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT" in SCANA's definitive proxy statement for the 2015 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

Equity securities issuable under SCANA's compensation plans at December 31, 2014 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
Long-Term Equity Compensation Plan	n/a	n/a	3,138,638
Non-Employee Director Compensation Plan	n/a	n/a	71,368
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	n/a	n/a	3,210,006

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: The information required by Item 13 is incorporated herein by reference to the captions “RELATED PARTY TRANSACTIONS” and “GOVERNANCE INFORMATION - Director Independence” in SCANA’s definitive proxy statement for the 2015 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA: The information required by Item 14 is incorporated herein by reference to “PROPOSAL 3-APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM” in SCANA’s definitive proxy statement for the 2015 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities and Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm’s Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to SCE&G and its consolidated affiliates for the fiscal years ended December 31, 2014 and 2013 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2014	2013
Audit Fees (1)	$ 1,977,658	$ 1,972,696
Audit-Related Fees (2)	123,107	115,706
Total Fees	$ 2,100,765	$ 2,088,402

(1) Fees for audit services billed in 2014 and 2013 consisted of audits of annual financial statements, comfort letters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under Item 8 herein.

The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under Item 8 herein.

The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts
(in millions)

Description		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2014	$ 6	$ 16	—	$ 15	$ 7
	2013	7	13	—	14	6
	2012	6	14	—	13	7
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2014	$ 6	$ 7	—	$ 8	$ 5
	2013	6	4	—	4	6
	2012	6	4	—	4	6
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2014	$ 3	$ 8	—	$ 7	$ 4
	2013	3	7	—	7	3
	2012	3	6	—	6	3
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2014	$ 5	$ 1	—	$ 3	$ 3
	2013	5	3	—	3	5
	2012	4	3	—	2	5

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

DATE: February 27, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Controller

(Principal Accounting Officer)

Other Directors*:

J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
D. M. Hagood	H. C. Stowe
J. M. Micali	A. Trujillo
L. M. Miller	

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 27, 2015

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director

DATE: February 27, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Controller
(Principal Accounting Officer)

Other Directors*:

J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
D. M. Hagood	H. C. Stowe
J. M. Micali	A. Trujillo
L. M. Miller	

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 27, 2015

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	Applicable to Form 10-K of SCE&G	Description
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of February 19, 2009 (Filed as Exhibit 4.04 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein)
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein)
4.03	X		First Supplemental Indenture dated as of November 1, 2009 to Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 99.01 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.04	X		Junior Subordinated Indenture dated as of November 1, 2009 between SCANA and U.S. Bank National Association, as Trustee (Filed as Exhibit 99.02 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.05	X		First Supplemental Indenture to Junior Subordinated Indenture referred to in Exhibit 4.04 dated as of November 1, 2009 (Filed as Exhibit 99.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.06		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein)
4.07		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein)
4.08		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein)
4.09		X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)
10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2008 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.03	X	X	SCANA Executive Deferred Compensation Plan (including amendments through November 25, 2014) (Filed herewith)
*10.04	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.05	X	X	SCANA Director Compensation and Deferral Plan (including amendments through November 30, 2014) (Filed herewith)
*10.06	X	X	SCANA Long-Term Equity Compensation Plan as amended and restated (including amendments through December 31, 2009) (Filed as Exhibit 99.06 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.07	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.08	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.09	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.10	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.11		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.12	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.13	X		Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents and JPMorgan Chase Bank, N.A., Mizuho Corporation Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on October 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.14	X	X	Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); File No. 001-00375 (SCE&G)) and incorporated by reference herein)
10.15	X	X	Three-Year Credit Agreement dated as of October 25, 2012, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.16	X	X	Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and JPMorgan Chase Bank, N.A., Mizuho Corporation Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.17	X		Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on October 30, 2012 (File No. 001-08809) and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith under the heading "Corporate Structure and Segments of Business" in Part I, Item I of this Form 10-K and incorporated by reference herein)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02	X		Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.03		X	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.04		X	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS**	X	X	XBRL Instance Document
101. SCH**	X	X	XBRL Taxonomy Extension Schema
101. CAL**	X	X	XBRL Taxonomy Extension Calculation Linkbase
101. DEF**	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB**	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE**	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Management Contract or Compensatory Plan or Arrangement

** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

Exhibit 10.03

SCANA CORPORATION

EXECUTIVE DEFERRED COMPENSATION PLAN

(including amendments through November 25, 2014)

SCANA CORPORATION

EXECUTIVE DEFERRED COMPENSATION PLAN

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SCANA CORPORATION

EXECUTIVE DEFERRED COMPENSATION PLAN

SECTION 1. ESTABLISHMENT AND PURPOSE

1 . 1 Establishment and History of the Plan. SCANA Corporation established, effective as of January 1, 1987, the supplementary voluntary deferred compensation plan for executives known as the "SCANA Corporation Supplementary Voluntary Deferral Plan" (the "SVDP"). SCANA Corporation also established: (1) effective as of October 15, 1986, a deferred compensation plan for executives known as the "SCANA Corporation Voluntary Deferral Plan" (the "VDP"); and (2) effective as of December 18, 1996, a consolidated deferred compensation plan for selected executives known as the "SCANA Corporation Key Employee Retention Program" ("KERP"), which was a consolidation of various individual agreements with executives, previously established. The VDP, KERP, and SVDP have been amended from time to time after their initial adoption for various design and administrative changes. Further, the VDP, KERP, and SVDP were amended and restated effective as of December 18, 1996 to include provisions applicable upon a Change in Control. The VDP, KERP, and SVDP were further amended and restated effective as of October 21, 1997 to include various administrative provisions and to clarify certain provisions regarding a Change in Control.

Effective as of July 1, 2000, the KERP was amended to provide a cash balance-type benefit for all participants. Effective as of July 1, 2001, the KERP and VDP were amended and merged with and into this Plan, which was re-named as the "SCANA Corporation Executive Deferred Compensation Plan" (hereinafter called the "Plan"). Effective as of January 1, 2002, the KERP cash balance-type benefit was frozen and this Plan was amended and restated to include new deferral opportunities as set forth herein. Effective as of January 1, 2004, this Plan was amended and restated to incorporate certain amendments and other design based changes. Effective as of January 1, 2007, this Plan was amended and restated to eliminate gross-up payments. Effective as of January 1, 2009, this Plan was amended and restated to comply with the requirements of Code Section 409A. Effective as of December 31, 2009, this Plan is amended and restated to remove references to the SCANA Corporation Key Executive Severance Benefits Plan. This Plan was most recently amended and restated, effective as of November 25, 2014, to allow for participation of non-employee directors of the Corporation in the Plan.

1.2 Description of the Plan. This Plan is intended to constitute a non-qualified deferred compensation plan which, in accordance with ERISA Sections 201(2), 301(a)(3) and 401(a)(1), is unfunded and established primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees.

1.3 Purpose of the Plan. The purpose of this Plan is to:

(a) enable the Company to attract and retain persons of outstanding competence, to provide incentive benefits to a very select group of key management employees who contribute materially to the continued growth, development, and future business success of the Company, and to provide a means whereby certain amounts payable by the Company to selected executives may be deferred to some future period; and

(b) provide a means whereby certain amounts payable by the Corporation to selected non-employee directors of the Corporation may be deferred to some future period.

1.4 Effective Date. This amended and restated Plan is effective as of November 25, 2014, except as otherwise specifically provided herein (including in the appendices to the Plan) or in resolutions adopted by the Board or the Committee.

SECTION 2. DEFINITIONS

2 . 1 Definitions. Whenever used herein, the following terms shall have the meanings set forth below, unless otherwise expressly provided herein or unless a different meaning is plainly required by the context, and when the defined meaning is intended, the term is capitalized:

(a) "Additional Deferral" means the pre-tax deferrals of Excess Compensation made by a Participant who is an Eligible Employee under this Plan of up to nineteen percent (19%) of his Excess Compensation in accordance with Section 4.1(b).

(b) "Agreement" means a contract between an Eligible Employee and the Company permitting the Eligible Employee to participate in the Plan and delineating the benefits (if any) that are to be provided to the Eligible Employee in lieu of or in addition to the benefits described under the terms of this Plan.

(c) "Basic Deferral" means the pre-tax deferrals of Excess Compensation made by a Participant who is an Eligible Employee under this Plan of up to six percent (6%) of his Excess Compensation in accordance with Section 4.1(a).

(d) "Beneficial Owner" shall have the meaning ascribed to such term in Rule 13d-3 of the General Rules and Regulations under the Exchange Act.

(e) "Beneficiary" means any person or entity who, upon the Participant's death, is entitled to receive the Participant's benefits under the Plan in accordance with Section 7 hereof.

(f) "Board" means the Board of Directors of the Corporation.

(g) "Bonus Deferral" means the pre-tax deferrals of a distribution of Performance Share Awards made by a Participant who is an Eligible Employee under this Plan of up to one hundred percent (100%) of his Performance Share Award in accordance with Section 4.1(c).

(h) "Cash Retainer Deferral" means the deferrals of Cash Retainer Fee amounts made by a Participant who is a Director under this Plan.

(i) "Change in Control" means a change in control of the Corporation of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Exchange Act, whether or not the Corporation is then subject to such reporting requirements; provided that, without limitation, such a Change in Control shall be deemed to have occurred if:

(i) Any Person (as defined in Section 3(a)(9) of the Exchange Act and used in Sections 13(d) and 14(d) thereof, including a "group" as defined in Section 13(d)) is or becomes the Beneficial Owner, directly or indirectly, of twenty five percent (25%) or more of the combined voting power of the outstanding shares of capital stock of the Corporation;

(ii) During any period of two (2) consecutive years (not including any period prior to December 18, 1996) there shall cease to be a majority of the Board comprised as follows: individuals who at the beginning of such period constitute the Board and any new director(s) whose election by the Board or nomination for election by the Corporation's stockholders was approved by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of the period or whose election or nomination for election was previously so approved;

(iii) The consummation of a merger or consolidation of the Corporation with any other corporation, other than a merger or consolidation which would result in the voting shares of capital stock of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting shares of capital stock of the surviving entity) at least eighty percent (80%) of the combined voting power of the voting shares of capital stock of the Corporation or such surviving entity outstanding immediately after such merger or consolidation; or the shareholders of the Corporation approve a plan of complete liquidation of the Corporation or an agreement for the sale or disposition by the Corporation of all or substantially all of the Corporation's assets; or

(iv) The consummation of the sale of the stock of any subsidiary of the Corporation designated by the Board as a "Material Subsidiary;" or the shareholders of the Corporation approve a plan of complete liquidation of a Material Subsidiary or an agreement for the sale or disposition by the Corporation of all or substantially all of the assets of a Material Subsidiary; provided that any event described in this subsection shall represent a Change in Control only with respect to a Participant who has been exclusively assigned to the affected Material Subsidiary.

(j) "Code" means the Internal Revenue Code of 1986, as amended.

(k) "Committee" means the Human Resources Committee of the Board. Any references in this Plan to the "Committee" shall be deemed to include references to the designee appointed by the Committee under Section 10.4.

(l) "Company" means the Corporation and any subsidiaries of the Corporation and their successor(s) or assign(s) that adopt this Plan through execution of Agreements with any of their Employees or otherwise. When the term "Company" is used with respect to an individual Participant who is an Eligible Employee, it shall refer to the specific company at which the Participant is employed, unless otherwise required by the context. When the term "Company" is used with respect to an individual Participant who is a Director, it shall refer to the Corporation.

(m) "Compensation" means the Eligible Earnings (as defined in the Qualified Plan) of a Participant who is an Employee, determined without regard to the limitation on compensation otherwise required under Code Section 401(a)(17), and without regard to any deferrals or the foregoing of compensation under this or any other plan of deferred compensation maintained by the Company.

(n) "Corporation" means SCANA Corporation, a South Carolina corporation, or any successor thereto.

(o) "Director" means an individual who is a member of the Board and who is designated as eligible to participate in this Plan by the Corporation under Section 3.1(b).

(p) "Director Plan" means the SCANA Corporation Director Compensation and Deferral Plan, as amended from time to time.

(q) "EDCP Ledger" means the bookkeeping ledger account used to track deferred amounts under the Plan together with credited earnings (or losses) that reflect the Investment Options applicable with respect to each Participant's deferred amounts. Each EDCP Ledger shall separately reflect the pre-2005 and post-2004 deferrals and hypothetical earnings thereon, and the portion of the post-2004 deferrals and hypothetical earnings thereon payable at a date certain and the portion payable upon a Participant's Separation from Service (referred to herein as a Participant's "pre-2005 EDCP Ledger" and "post-2004 EDCP Ledger"). A Participant's pre-2005 EDCP Ledger shall reflect amounts deferred hereunder before January 1, 2005 (and the earnings credited thereon before, on or after January 1, 2005) for which (i) the Participant had a legally binding right as of December 31, 2004, to be paid the amount, and (ii) such right to the amount was earned and vested as of December 31, 2004 and was credited to the Participant's EDCP Ledger hereunder. Pre-2005 EDCP Ledgers are treated as "grandfathered" for the purposes of Code Section 409A, and are governed by the terms of the Plan in effect as of October 3, 2004.

(r) "Eligible Employee" means an Employee who is eligible for awards under the SCANA Corporation Long-Term Equity Compensation Plan.

(s) "Employee" means a person who is actively employed by the Company and who falls under the usual common law rules applicable in determining the employer-employee relationship.

(t) "Employer Matching Deferral" means the deferrals credited to EDCP Ledgers for Participants who are Eligible Employees in accordance with Section 4.2.

(u) "ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

(v) "Excess Compensation" means the Compensation otherwise payable to an Eligible Employee in excess of the dollar limitation imposed under Code Section 401(a)(17) (or such other dollar limitation as may be set by the Committee in its sole discretion for any Year).

(w) "Exchange Act" means the Securities Exchange Act of 1934, as amended.

(x) "Investment Options" means those hypothetical targeted investment options designated by the Committee as measurements of the rate of return to be credited to (or charged against) Participants' EDCP Ledgers.

(y) "Participant" means any Eligible Employee or Director who is participating in the Plan in accordance with the provisions herein set forth. If a Participant had previously deferred amounts credited to a EDCP Ledger and such Participant is no longer eligible to participate hereunder (for example, due to a Committee designation of his ineligibility), he shall be covered under this Plan as an inactive Participant. Except for those provisions related to deferral opportunities, references herein to a Participant shall be deemed to include references to such inactive Participants, unless otherwise required by the context.

(z) "Performance Share Award" means the amount payable from the Performance Share Award portion of the SCANA Corporation Long-Term Equity Compensation Plan to a Participant who is an Eligible Employee in a Year.

(aa) "Qualified Plan" means the SCANA Corporation Stock Purchase-Savings Plan, as amended from time to time.

(bb) "Retainer Fee" means the amount of compensation payable to a Director with respect to services rendered to the Corporation as a Director for a Year under the Director Plan. With respect to Retainer Fee amounts deferred by a Director under this Plan, the Corporation or its delegate shall designate a portion of the Retainer Fee as the "Stock Retainer Fee" and a portion of the Retainer Fee as the "Cash Retainer Fee."

(cc) "Separation from Service" means:

(i) with respect to an Employee, any termination of the employment relationship from the Company and any affiliates and, with respect to post-2004 EDCP Ledgers, any separation from service from the Company and its affiliates as determined in a manner consistent with Code Section 409A and the guidelines issued thereunder; and

(ii) with respect to a Director, any separation from service from the Company and its affiliates as determined in a manner consistent with Code Section 409A and the guidelines issued thereunder.

(dd) "Stock Retainer Deferral" means the deferrals of Cash Retainer Fee amounts made by a Participant who is a Director under this Plan.

(ee) "Year" means the calendar year.

2.2 Gender and Number. Except when otherwise indicated by the context, any masculine terminology used herein also shall include the feminine and the feminine shall include the masculine, and the use of any term herein in the singular may also include the plural and the plural shall include the singular.

SECTION 3. ELIGIBILITY AND PARTICIPATION

3.1 Eligibility.

(a) An Eligible Employee shall become eligible to participate in this Plan as follows:

(i) To be eligible to participate in this Plan for purposes of making Basic Deferrals or Additional Deferrals (and to benefit from Employer Matching Deferrals) for any Year, the Eligible Employee must earn Compensation during that Year in excess of the applicable dollar limitation on compensation under Code Section 401(a)(17) (or such other dollar limitation as may be set by the Committee in its sole discretion for any Year before the beginning of such Year) and the Eligible Employee must have elected to defer the maximum allowable pre-tax deferrals under the Qualified Plan for the Year.

(ii) Eligible Employees are automatically eligible to participate in this Plan for purposes of making Bonus Deferrals.

(b) A Director shall become eligible to participate in the Plan for purposes of making Cash Retainer Deferrals and Stock Retainer Deferrals upon his satisfaction of the Corporation's minimum share ownership guidelines applicable to Directors, as certified by the Board.

(c) All Eligible Employees and Directors will be required, as a condition of participation, to execute such written participation agreements as required by the Committee from time to time.

3.2 Participation. An Employee or Director who meets the eligibility requirements of Section 3.1 may become a Participant in this Plan by electing to defer a portion of his Excess Compensation, Performance Share Award or Retainer Fee, as applicable, on such form and in such manner as determined by the Committee pursuant to Section 4. Eligible Employees who are participants in the Qualified Plan may automatically be deemed to have elected to defer a portion of their Excess Compensation hereunder in accordance with Section 4.

3.3 Continued Participation. Once an Eligible Employee or Director becomes a Participant, he shall continue to be eligible to participate for all future years until his Separation from Service or death or unless and until the Committee shall designate that individual as ineligible to participate. If a Participant becomes ineligible to participate for future deferrals under this Plan, he shall retain all the rights described under this Plan with respect to deferrals previously made while an active Participant.

SECTION 4. DEFERRALS

4 . 1 Deferral Election for Eligible Employees. Subject to the conditions set forth in this Plan, a Participant who is an Eligible Employee may elect to defer amounts hereunder as follows:

(a) Basic Deferrals. An Eligible Employee may elect to defer Basic Deferrals under this Plan in whole percentages up to six percent (6%) of his Excess Compensation.

(b) Additional Deferrals. An Eligible Employee may elect to defer Additional Deferrals under this Plan in whole percentages up to nineteen percent (19%) of his Excess Compensation.

(c) Bonus Deferrals. An Eligible Employee may elect to defer under this Plan, in whole percentages, up to one hundred percent (100%) of his Performance Share Award otherwise payable for a Year, as a Bonus Deferral.

(d) Deferral Procedures for Basic and Additional Deferrals. Except as provided in Section 4.1(f), all elections under Section 4.1(a) and Section 4.1(b) must be made at such time and in such manner as specified by the Committee prior to the beginning of the Year in which such Excess Compensation is otherwise earned. The Committee is permitted but not required to establish deferral procedures pursuant to which Participants are eligible to make separate deferral elections with respect to base salary and short-term incentive awards. Once a Basic Deferral or Additional Deferral election is made (or deemed to be made) for a Year, it shall remain in effect for all future Excess Compensation otherwise payable in all future pay periods during that Year. Such election shall also remain in effect for future Years unless affirmatively changed by the Participant in accordance with the terms of the Plan and the procedures implemented hereunder prior to the beginning of such Year. Eligible Employee Basic Deferrals and Additional Deferrals shall be credited to the Participant's EDCP Ledger(s) at such times and in such manner as determined by the Committee, in its sole discretion, but no less frequently than monthly.

(e) Deferral Procedures for Bonus Deferrals. Elections made under Section 4.1(c) must be made no later than June 30 of the first Year of the three-Year award cycle established under the Performance Share Award portion of the SCANA Corporation Long-Term Equity Compensation Plan, and shall apply to the Participant's award that is otherwise payable, if at all, in the Year following the end of the three-Year award cycle; provided that in order to be eligible to make the election by such June 30 date, the Participant continuously performs services from the beginning of the performance period through the date on which the election is made. Any such Bonus Deferral election shall also apply with respect to awards payable in future Years of such three-Year award cycle unless affirmatively changed by the Participant in accordance with the procedures established by the Committee prior to June 30 of any of the Years in the three-Year award cycle applicable to such award with respect to which a change is requested. Any Bonus Deferral election shall also apply with respect to awards payable pursuant to future three-Year award cycles unless affirmatively changed by the Participant in accordance with the terms of the Plan and the procedures implemented hereunder prior to June 30 of the first Year of the future three-Year award cycle. Eligible Employee Bonus Deferrals shall be credited to the Participant's EDCP Ledger(s) in such manner as determined by the Committee, in its sole discretion, but no later than as of the last business day of the month following the month in which the Participant's Performance Share Award is otherwise payable.

(f) Deferral Procedures for Newly Eligible Employees. In the case of a person who first becomes an Eligible Employee during a Year (and is not eligible for any other plan with which this Plan is aggregated for purposes of Code Section 409A), elections under Section 4.1(a), 4.1(b), and 4.1(c) for such Year must be made within thirty (30) days of the date the Employee becomes an Eligible Employee, and shall apply only to amounts paid for services to be performed after the date of such election.

4.2 Deferral Election for Directors. Subject to the conditions set forth in this Plan, a Participant who is a Director may elect to defer amounts hereunder as follows:

(a) Cash Retainer Deferrals. A Director who has not elected to defer all or a portion of his Cash Retainer Fee amounts for a Year under the Director Plan may elect to defer Cash Retainer Deferrals under this Plan in whole percentages up to one hundred percent (100%) of his Cash Retainer Fee amounts for a Year.

(b) Stock Retainer Deferrals. A Director who has not elected to defer all or a portion of his Stock Retainer Fee amounts under the Director Plan for a Year may elect to defer Stock Retainer Deferrals under this Plan of one hundred percent (100%) of his Stock Retainer Fee amounts for a Year. For clarity, if a Director elects to defer Stock Retainer Fee amounts under this Plan for a Year, he must deferral all of his Stock Retainer Fee and may not defer less than one hundred percent (100%) of his Stock Retainer Fee amounts for such Year under this Plan.

(c) Deferral Procedures for Cash Retainer Deferrals and Stock Retainer Deferrals. All elections under Section 4.2(a) and 4.2(b) must be made at such time and in such manner as specified by the Committee prior to the beginning of the Year in which such Retainer Fee amounts are otherwise earned. The Committee is permitted but not required to establish deferral procedures pursuant to which Participants are eligible to make separate deferral elections with respect to Cash Retainer Fees and Stock Retainer Fees. Once a Cash Retainer Deferral or Stock Retainer Deferral election is made (or deemed to be made) for a Year, it shall remain in effect for all future Retainer Fees otherwise payable in all future periods during that Year. Such election shall also remain in effect for future Years unless affirmatively changed by the Participant in accordance with the terms of the Plan and the procedures implemented hereunder prior to the beginning of such Year. Director Cash Retainer Deferrals and Stock Retainer Deferrals shall be credited to the Participant's EDCP Ledger(s) at such times and in such manner as determined by the Committee, in its sole discretion, but no less frequently than quarterly.

4.3 Crediting of Employer Matching Deferrals. Any Participant who has elected to make a deferral under Section 4.1(a) or 4.1(b) for a Year will be credited with an Employer Matching Deferral for such Year of an amount equal to such deferral, provided that the total amount of a Participant's Employer Matching Deferral for any Year shall not exceed an amount equal to 6% of the Participant's Excess Compensation. Such Employer Matching Deferrals shall be credited to the Participant's "Separation from Service" EDCP Ledger at such times and in such manner as the Committee, in its sole discretion determines, but no less frequently than monthly.

4.4 Deferral Period. With respect to deferrals made in accordance with Section 4.1 or Section 4.2, each Participant may elect the deferral period for each separate deferral. Subject to the modification of deferral date provisions of Section 4.6 and the acceleration provisions of Section 6, (i) a Participant who is an Eligible Employee may elect to defer his Basic Deferrals, Additional Deferrals, and Bonus Deferrals until his Separation from Service or until a date certain; provided, however, that any post-2004 deferrals must have the same date certain; and (ii) a Participant who is a Director may elect to defer his Cash Retainer Deferrals and Stock Retainer Deferrals only until his Separation from Service. All deferrals are subject to the establishment of EDCP Ledgers in accordance with Section 5.1 and any additional limitations that the Committee in its sole discretion may choose to apply (which limitations shall be applied in accordance with Code Section 409A with respect to post-2004 EDCP Ledgers).

Notwithstanding any "date certain" deferral period election otherwise made by a Participant who is an Eligible Employee (or any modification thereof under Section 4.6), and except as otherwise provided in Section 4.5(b) in connection with a modification of the form of distribution for post-2004 EDCP Ledger(s), payments of deferred amounts hereunder shall be paid or begin to be paid as soon as practicable following the earliest to occur of:

(a) Death,

(b) "Disability," as defined by the long-term disability provisions of the SCANA Corporation Health and Disability Plan (but only for pre-2005 EDCP Ledgers), or

(c) Separation from Service for any reason, subject to the rules in Section 6.6 applicable to "specified employees."

4.5 Form of Payment of Deferred Amounts. At the same time as the election made pursuant to Section 4.1, Section 4.2 and Section 4.4, and subject to the acceleration provisions of Section 6, each Participant must also elect the manner in which his deferred amounts will be paid.

(a) Mandatory Single Sum Cash Payments. All amounts that are to be paid at a date certain prior to a Participant's Separation from Service, death, or Disability (but only for pre-2005 EDCP Ledgers) must be paid in the form of a single sum cash payment. Also, except as provided in Section 4.5(b), all deferred amounts otherwise payable upon a Participant's Separation from Service, death, or Disability (but only for pre-2005 EDCP Ledgers) shall be paid in the form of a single sum cash payment.

(b) Optional Forms of Distribution. In lieu of a single sum cash payment, a Participant may elect to have all amounts payable hereunder on account of Separation from Service after his attainment of age 55, death while employed or providing service as a Director, as applicable, and after attainment of age 55, or Separation from Service due to Disability (but only for pre-2005 EDCP Ledgers), paid in the form of annual installment payments over a period not to exceed five (5) years for the post-2004 EDCP Ledger (fifteen (15) years for pre-2005 EDCP Ledgers) commencing as soon as practicable after such Separation from Service, death or Disability (only for pre-2005 EDCP Ledgers). A Participant may elect to change his election as to the form of payment of deferred amounts at any time before his Separation from Service; provided, however, that an election as to a form of payment shall not be valid unless it has been in effect for at least twelve (12) months before the Participant's Separation from Service, death or Disability (only for pre-2005 EDCP Ledgers) and, for post-2004 EDCP Ledgers, the Participant postpones the commencement date for five (5) years beyond the date payment would otherwise have commenced in the absence of the election. If an election otherwise made is not effective because it was not in effect for at least twelve (12) months before the Participant's Separation from Service, death or Disability (but only for pre-2005 EDCP Ledgers), the last valid distribution election shall be effective or, in the absence of a valid election, all amounts shall be paid in the form of a single sum cash payment. Unless specifically elected otherwise, payments of all deferred amounts will be made in a single lump sum cash payment paid as soon as practicable after the conclusion of the applicable deferral period pursuant to Section 4.4.

4 . 6 Modification of Deferral Date. A Participant who is an Eligible Employee may request that the Committee approve a modification to his "date certain" deferral, as follows:

(a) A Participant may request that the Committee approve an additional deferral period of at least sixty (60) months for the post-2004 EDCP Ledger (at least twelve (12) months for the pre-2005 EDCP Ledger) with respect to any amount that was initially deferred to a "date certain" EDCP Ledger. Any such request must be made, in accordance with such procedures established by the Committee, in its discretion, at least twelve (12) months before the expiration of the date certain deferral period for the deferred amount for which an additional deferral election is requested. Notwithstanding the foregoing, if a Participant had previously deferred amounts to a "Separation from Service" EDCP Ledger and subsequently elected to accelerate the distribution of all or part of such amounts attributable to pre-2005 EDCP Ledgers to a date certain, pursuant to Section 6.4(b), that election is irrevocable and the Participant may not make any further deferral elections with respect to such amounts.

(b) A Participant may request, in accordance with such procedures established by the Committee, in its discretion, that the Committee approve a modified deferral date for the Participant's "date certain" pre-2005 EDCP Ledger as long as the modified deferral date is no earlier than twelve (12) months from the date of such election and the original date certain to which amounts were deferred is not within twelve (12) months from the date of such modification election.

SECTION 5. EDCP LEDGERS – DEFERRED COMPENSATION ACCOUNTS

5 . 1 Participant Accounts. The Committee shall establish and maintain for each Participant a bookkeeping account or accounts to track deferrals made by such Participant. Such accounts shall be referred to herein as "EDCP Ledgers." Deferred amounts shall be credited to each Participant's EDCP Ledger(s) at such times as required under Section 4. Effective as of January 1, 2002, no more than two EDCP Ledgers may be established at any time for any Participant reflecting amounts deferred to a date certain for Eligible Employee's only (the Participant's "date certain" EDCP Ledger) separately from amounts initially deferred to Separation from Service (the Participant's "Separation from Service" EDCP Ledger). Each such EDCP Ledger shall separately reflect the pre-2005 deferrals and post-2004 deferrals. Once amounts are completely paid from the "date certain" EDCP Ledger for a Participant who is an Eligible Employee, such Participant may establish a new "date certain" EDCP Ledger for future deferrals. In addition to deferrals otherwise provided for under Section 4, any Participant's cash balance account amounts transferred to this Plan from the KERP shall be credited to the Participant's pre-2005 "Separation from Service" EDCP Ledger.

5.2 Hypothetical Earnings . Additional amounts shall be credited to (or deducted from) a Participant's EDCP Ledgers to reflect the hypothetical earnings (or losses) that would have been experienced had the deferred amounts been invested in the Investment Options selected by the Participant pursuant to his investment election. The Committee shall establish such procedures as it deems necessary, in its sole discretion, to allow Participants the ability to designate that all or a portion of amounts deferred to their EDCP Ledgers be hypothetically invested among the Investment Options. The Committee is authorized to select an Investment Option to serve as a default Investment Option in the absence of an actual election by any Participant. All amounts credited to Participants' EDCP Ledgers shall continue to be hypothetically invested among the Investment Options until such amounts are paid in full to the Participant (or his Beneficiary). Notwithstanding the foregoing, and subject to Section 9.2, no Participant shall have a right to designate the specific actual investment of deferred amounts.

5.3 Charges Against Accounts. There shall be charged against each Participant's account any payments made to the Participant or to his Beneficiary in accordance with Section 6 hereof.

SECTION 6. PAYMENT OF DEFERRED AMOUNTS

6.1 Payment of Deferred Amounts. Payment of a Participant's EDCP Ledger(s), including accumulated hypothetical earnings (or losses), shall be paid in cash commencing with the conclusion of the deferral period otherwise provided in Section 4. The payments shall be made in the manner selected by the Participant under Section 4.5. The amount of any annual installment payment shall equal the Participant's distributable EDCP Ledger(s), determined as of the last day of the month preceding the payment date multiplied by a fraction, the numerator of which is one and the denominator of which is the number of installment payments remaining to be paid.

6.2 Acceleration of Payments. Notwithstanding the deferral period otherwise applicable to deferred amounts hereunder:

(a) if a Participant dies after commencement of installment payments and prior to the payment of all amounts credited to his EDCP Ledger(s), the balance of any amount payable shall continue to be paid in installment distributions, unless:

(i) with respect to pre-2005 EDCP Ledgers only, the Participant's Beneficiary is not a natural person (or a trust, the beneficiary of which is a natural person);

(ii) the Participant's Beneficiary elects to accelerate the amounts remaining to be paid, pursuant to Section 6.3 or Section 6.4 (with respect to pre-2005 EDCP Ledgers); or

(iii) if a Participant dies after commencement of installment payments and prior to the payment of all amounts credited to his EDCP Ledger(s), the balance of any amount payable with respect to post-2004 EDCP Ledger(s) shall be paid in a lump sum; and

(b) if the total amount payable from a Participant's pre-2005 EDCP Ledger(s) is less than five thousand dollars ($5,000) (one hundred thousand dollars ($100,000) for post-2004 Ledger(s)) at the time for payment specified, such amount shall be paid in a lump sum.

6.3 Unforeseeable Emergency. At any time before the time an amount is otherwise payable hereunder, a Participant (or the Participant's Beneficiary) may request, pursuant to such procedures prescribed by the Committee in its sole discretion, a single sum cash distribution of all or a portion of the amounts credited to his EDCP Ledger(s) due to the Participant's (or the Beneficiary's) severe financial hardship, subject to the following requirements set forth in this Section 6.3. The rules set forth in this Section 6.3 govern distributions of post-2004 EDCP Ledgers in the case of an unforeseeable emergency. Distributions of pre-2005 EDCP Ledgers in the case of an unforeseeable emergency shall be governed by terms of the Plan in effect as of October 3, 2004.

(a) Such distribution shall be made, in the sole discretion of the Committee, in the case of an unforeseeable emergency, which shall be limited to a severe financial hardship to the Participant resulting from an illness or accident of the Participant, the Participant's spouse, the Participant's Beneficiary, or of a Participant's dependent (as defined in Code Section 152, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)), loss of the Participant's property due to casualty (including the need to rebuild a home following damage to a home not otherwise covered by insurance, for example, not as a result of a natural disaster); or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. Examples of events that may constitute an unforeseeable emergency include the imminent foreclosure of or eviction from the Participant's primary residence; the need to pay for medical expenses, including non-refundable deductibles, as well as for the costs of prescription drug medication; and the need to pay for the funeral expenses of the Participant's spouse, the Participant's Beneficiary, or the Participant's dependent (as defined in Code Section 152, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)).

(b) Whether a Participant is faced with an unforeseeable emergency will be determined based on the relevant facts and circumstances of each case, but, in any case, a distribution on account of an unforeseeable emergency may not be made to the extent that such emergency is or may be relieved:

(i) through reimbursement or compensation by insurance or otherwise,

(ii) by liquidation of the individual's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship, or

(iii) by cessation of deferrals under the Plan.

Examples of circumstances that are not considered to be unforeseeable emergencies include the need to send an individual's child to college or the desire to purchase a home.

(c) In all events, the amount available for distribution on account of an unforeseeable emergency pursuant to this Section 6.3 shall be limited to the amount reasonably necessary to satisfy the emergency need (which may include amounts necessary to pay any federal, state, local, or foreign income taxes or penalties reasonably anticipated to result from the distribution), and shall be determined in accordance with Code Section 409A and the regulations thereunder. The Committee may require such evidence of the individual's severe financial hardship as it deems appropriate. The Committee shall consider any requests for payment under this Section 6.3 in accordance with the standards of interpretation described in Code Section 409A and the regulations and other guidance thereunder.

(d) All distributions under this Section 6.3 shall be made from the Participant's EDCP Ledger(s) as soon as practicable after the Committee has approved the distribution and the amounts credited to the Participant's EDCP Ledger(s) shall be reduced on a pro rata basis among his elected Investment Options to reflect the accelerated distribution.

6.4 Acceleration Subject to Substantial Limitations. At any time before an amount is otherwise payable hereunder, a Participant (or the Participant's Beneficiary) may request, pursuant to such procedures prescribed by the Committee in its sole discretion, that an accelerated distribution of all or a portion of the amounts credited to his pre-2005 EDCP Ledger(s) be made pursuant to the following provisions:

(a) An individual may accelerate all or any portion of his pre-2005 EDCP Ledger(s) and have such amount paid in the form of a single sum cash payment as soon as practicable after receipt of such request by the Committee; provided, however, that an amount equal to ten percent (10%) of the amount requested by the Participant will be forfeited from the Participant's EDCP Ledger(s) immediately prior to such payment.

(b) In lieu of (or in addition to) any acceleration payment under Section 6.4(a) above, an individual may elect to accelerate the payment of all or any portion of the amounts otherwise payable from his pre-2005 EDCP Ledger(s), provided that:

(i) the accelerated amounts are not otherwise payable within twelve (12) months of the date of such election;

(ii) the accelerated amounts must be paid in the form of a single sum cash payment at the date specified by the individual; and

(iii) the accelerated payment may not be paid any earlier than twelve (12) months after the date such acceleration election is received by the Committee.

(c) No individual may make more than two acceleration elections with respect to the individual's pre-2005 EDCP Ledger(s) in any Year.

(d) All distributions under this Section 6.4 shall be made from the Participant's pre-2005 EDCP Ledger(s) in a single sum cash payment as soon as practicable after the date approved by the Committee and the amounts credited to the Participant's pre-2005 EDCP Ledger(s) shall be reduced on a pro rata basis among his elected Investment Options to reflect the accelerated distribution.

6 . 5 Committee Modification of Installment Distribution Options. Notwithstanding anything to the contrary in this Plan, the Committee, in its sole discretion, may choose to accelerate any installment distribution amounts otherwise payable hereunder from pre-2005 Ledgers to a Participant (or Beneficiary), with or without the consent of the Participant (or Beneficiary).

6 . 6 Delay in Distribution for Specified Employees. Notwithstanding anything to the contrary in this Plan, if the Participant is a "specified employee," as determined in accordance with procedures adopted by the Corporation that reflect the requirements of Code Section 409A(a)(2)(B)(i), distribution of the post-2004 EDCP Ledgers which is made on account of the Participant's Separation from Service shall be deferred until the earlier of (i) first day of the seventh month following the Participant's Separation from Service (without regard to whether the Participant is reemployed on that date) or (ii) the date of the Participant's death.

6.7 Compliance with Domestic Relations Order. Notwithstanding anything to the contrary in this Plan, a distribution shall be made from the Participant's EDCP Ledgers to an individual other than the Participant to the extent necessary to comply with a domestic relations order (as defined in Code Section 414(p)(1)(B)).

SECTION 7. BENEFICIARY DESIGNATION

7.1 Designation of Beneficiary. A Participant shall designate a Beneficiary or Beneficiaries who, upon the Participant's death, are to receive the amounts that otherwise would have been paid to the Participant. All designations shall be in writing and signed by the Participant. The designation shall be effective only if and when delivered to the Corporation during the lifetime of the Participant. The Participant also may change his Beneficiary or Beneficiaries by a signed, written instrument delivered to the Corporation. The payment of amounts shall be in accordance with the last unrevoked written designation of Beneficiary that has been signed and delivered to the Corporation. All Beneficiary designations shall be addressed to the Secretary of SCANA Corporation and delivered to his office.

7.2 Death of Beneficiary.

(a) In the event that all of the Beneficiaries named in Section 7.1 predecease the Participant, the amounts that otherwise would have been paid to said Beneficiaries shall, where the designation fails to redirect to alternate Beneficiaries in such circumstance, be paid to the Participant's estate as the alternate Beneficiary.

(b) In the event that two or more Beneficiaries are named, and one or more but less than all of such Beneficiaries predecease the Participant, each surviving Beneficiary shall receive any dollar amount or proportion of funds designated or indicated for him per the designation of Section 7.1, and the dollar amount or designated or indicated share of each predeceased Beneficiary which the designation fails to redirect to an alternate Beneficiary in such circumstance shall be paid to the Participant's estate as an alternate Beneficiary.

7.3 Ineffective Designation.

(a) In the event the Participant does not designate a Beneficiary, or if for any reason such designation is entirely ineffective, the amounts that otherwise would have been paid to the Beneficiary shall be paid to the Participant's estate as the alternate Beneficiary.

(b) In the circumstance that designations are effective in part and ineffective in part, to the extent that a designation is effective, distribution shall be made so as to carry out as closely as discernable the intent of the Participant, with result that only to the extent that a designation is ineffective shall distribution instead be made to the Participant's estate as an alternate Beneficiary.

SECTION 8. CHANGE IN CONTROL PROVISIONS

8.1 Successors. Notwithstanding anything in this Plan to the contrary, upon the occurrence of a Change in Control, the Company will require any successor (whether direct or indirect, by purchase, merger, consolidation, or otherwise) of all or substantially all of the business and/or assets of the Company or of any division or subsidiary thereof to expressly assume and agree to perform this Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place, subject to the remaining provisions of this Section 8.1. Participants shall become entitled to benefits hereunder in accordance with the terms of this Plan based on amounts credited to each Participant's EDCP Ledger(s) as of the date of such Change in Control plus accumulated hypothetical earnings (or losses) attributable thereto (adjusted to reflect any change from the most recent EDCP Ledger calculation to the end of the month prior to the month such amounts are distributed to each Participant, based on the Investment Options in effect at such time). In the case of any Change in Control, any successor to the Company shall not be required to provide for additional deferral of benefits beyond the date of such Change in Control except as required under Code Section 409A.

8.2 Amendment and Termination After Change in Control. Notwithstanding the foregoing, and subject to this Section 8, no amendment, modification or termination of the Plan may be made, and no Participants may be added to the Plan, upon or following a Change in Control if it would have the effect of reducing any benefits earned (including optional forms of distribution) by any Participant prior to such Change in Control without the written consent of all of the Plan's Participants covered by the Plan at such time. In all events, however, the Corporation reserves the right to amend, modify or delete the provisions of Section 8 at any time prior to a Change in Control, pursuant to a Board resolution adopted by a vote of two-thirds (2/3) of the Board members then serving on the Board.

SECTION 9. GENERAL PROVISIONS

9.1 Contractual Obligation. It is intended that the Corporation is under a contractual obligation to make payments from a Participant's account when due. Payment of account balances shall be made out of the general funds of the Corporation as determined by the Board without any restriction of the assets of the Corporation relative to the payment of such contractual obligations; the Plan is, and shall operate as, an unfunded plan.

9.2 Unsecured Interest. No Participant or Beneficiary shall have any interest whatsoever in any specific asset of the Corporation. To the extent that any person acquires a right to receive payment under this Plan, such right shall be no greater than the right of any unsecured general creditor of the Corporation.

9.3 "Rabbi" Trust. In connection with this Plan, the Board has established a grantor trust (known as the "SCANA Corporation Executive Benefit Plan Trust" and referred to herein as the "Trust") for the purpose of accumulating funds to satisfy the obligations incurred by the Corporation under this Plan (and such other plans and arrangements as determined from time to time by the Corporation). At any time prior to a Change in Control, as that term is defined in such Trust, the Corporation may transfer assets to the Trust to satisfy all or part of the obligations incurred by the Corporation under this Plan, as determined in the sole discretion of the Committee, subject to the return of such assets to the Corporation at such time as determined in accordance with the terms of such Trust. Notwithstanding the establishment of the Trust, the right of any Participant to receive future payments under the Plan shall remain an unsecured claim against the general assets of the Corporation.

9.4 Employment/Participation Rights.

(a) Nothing in the Plan shall interfere with or limit in any way the right of the Company to terminate any Participant's employment or service at any time, nor confer upon any Participant any right to continue in the employ or service of the Company.

(b) Nothing in the Plan shall be construed to be evidence of any agreement or understanding, express or implied, that the Company will continue to employ or require the services of a Participant in any particular position or at any particular rate of remuneration.

(c) No employee or director shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant.

(d) Nothing in this Plan shall affect the right of a recipient to participate in and receive benefits under and in accordance with any pension, profit-sharing, deferred compensation or other benefit plan or program of the Company.

9.5 Nonalienation of Benefits.

(a) Subject to Section 6.7, no right or benefit under this Plan shall be subject to anticipation, alienation, sale, assignment, pledge, encumbrance, or change, and any attempt to anticipate, alienate, sell, assign, pledge, encumber or change the same shall be void; nor shall any such disposition be compelled by operation of law.

(b) No right or benefit hereunder shall in any manner be liable for or subject to the debts, contracts, liabilities, or torts of the person entitled to benefits under the Plan.

(c) If any Participant or Beneficiary hereunder should become bankrupt or attempt to anticipate, alienate, sell, assign, pledge, encumber, or change any right or benefit hereunder (other than as permitted in Section 6.7), then such right or benefit shall, in the sole discretion of the Committee, cease, and the Committee shall direct in such event that the Corporation hold or apply the same or any part thereof for the benefit of the Participant or Beneficiary in such manner and in such proportion as the Committee may deem proper.

9.6 Severability. If any particular provision of the Plan shall be found to be illegal or unenforceable for any reason, the illegality or lack of enforceability of such provision shall not affect the remaining provisions of the Plan, and the Plan shall be construed and enforced as if the illegal or unenforceable provision had not been included.

9.7 No Individual Liability. It is declared to be the express purpose and intention of the Plan that no liability whatsoever shall attach to or be incurred by the shareholders, officers, or directors of the Corporation or any representative appointed hereunder by the Corporation, under or by reason of any of the terms or conditions of the Plan.

9.8 Applicable Law. This Plan shall be governed by and construed in accordance with the laws of the State of South Carolina except to the extent governed by applicable federal law (including the requirements of Code Section 409A).

SECTION 10. PLAN ADMINISTRATION, AMENDMENT AND TERMINATION

10.1 In General. This Plan shall be administered by the Committee, which shall have the sole authority, in its sole discretion, to construe and interpret the terms and provisions of the Plan and determine the amount, manner and time of payment of any benefits hereunder. The Committee shall maintain records, make the requisite calculations and disburse payments hereunder, and its interpretations, determinations, regulations and calculations shall be final and binding on all persons and parties concerned. The Committee may adopt such rules as it deems necessary, desirable or appropriate in administering this Plan and the Committee may act at a meeting, in a writing without a meeting, or by having actions otherwise taken by a member of the Committee pursuant to a delegation of duties from the Committee.

10.2 Claims Procedure. Any person dissatisfied with the Committee's determination of a claim for benefits hereunder must file a written request for reconsideration with the Committee. This request must include a written explanation setting forth the specific reasons for such reconsideration. The Committee shall review its determination promptly and render a written decision with respect to the claim, setting forth the specific reasons for such denial written in a manner calculated to be understood by the claimant. Such claimant shall be given a reasonable time within which to comment, in writing, to the Committee with respect to such explanation. The Committee shall review its determination promptly and render a written decision with respect to the claim. Such decision upon matters within the scope of the authority of the Committee shall be conclusive, binding, and final upon all claimants under this Plan.

10.3 Finality of Determination. The determination of the Committee as to any disputed questions arising under this Plan, including questions of construction and interpretation, shall be final, binding, and conclusive upon all persons.

10.4 Delegation of Authority. The Committee may, in its discretion, delegate its duties to an officer or other Employee of the Company, or to a committee composed of officers or Employees of the Company.

10.5 Expenses. The cost of payment from this Plan and the expenses of administering the Plan shall be borne by the Corporation.

10.6 Tax Withholding. The Corporation shall have the right to deduct from all payments made from the Plan any federal, state, or local taxes required by law to be withheld with respect to such payments.

10.7 Incompetency. Any person receiving or claiming benefits under the Plan shall be conclusively presumed to be mentally competent and of age until the Committee receives written notice, in a form and manner acceptable to it, that such person is incompetent or a minor, and that a guardian, conservator, statutory committee under the South Carolina Code of Laws, or other person legally vested with the care of his estate has been appointed. In the event that the Committee finds that any person to whom a benefit is payable under the Plan is unable to properly care for his affairs, or is a minor, then any payment due (unless a prior claim therefor shall have been made by a duly appointed legal representative) may be paid to the spouse, a child, a parent, or a brother or sister, or to any person deemed by the Committee to have incurred expense for the care of such person otherwise entitled to payment.

In the event a guardian or conservator or statutory committee of the estate of any person receiving or claiming benefits under the Plan shall be appointed by a court of competent jurisdiction, payments shall be made to such guardian or conservator or statutory committee provided that proper proof of appointment is furnished in a form and manner suitable to the Committee. Any payment made under the provisions of this Section 10.7 shall be a complete discharge of liability therefor under the Plan.

10.8 Notice of Address. Any payment made to a Participant or to his designated Beneficiary at the last known post office address of the distributee on file with the Corporation, shall constitute a complete acquittance and discharge to the Corporation and any director or officer with respect thereto, unless the Corporation shall have received prior written notice of any change in the condition or status of the distributee. Neither the Corporation nor any director or officer shall have any duty or obligation to search for or ascertain the whereabouts of the Participant or his designated Beneficiary.

10.9 Amendment and Termination. The Corporation expects the Plan to be permanent but, because future conditions affecting the Corporation cannot be anticipated or foreseen, the Corporation reserves the right to amend, modify, or terminate the Plan at any time by action of its Board, subject to Section 8.2 and subject to the requirements of Code Section 409A with respect to post-2004 EDCP Ledgers; provided, however, that any such action shall not diminish retroactively any amounts, both deferred amounts and any hypothetical earnings (or losses) thereon, which have been credited to any Participant's EDCP Ledger(s). If the Board amends the Plan to cease future deferrals hereunder or terminates the Plan, the Board may, in its sole discretion, direct that the value of each Participant's EDCP Ledger(s) be paid to each Participant (or Beneficiary, if applicable) in an immediate lump sum payment; provided, however, that in the case of any post-2004 EDCP Ledger(s), the requirements of Reg. § 1.409A-3(j)(4)(ix) are met. In the absence of any such direction from the Board, the Plan shall continue as a "frozen" plan under which no future deferrals will be recognized unless required under Code Section 409A (however, hypothetical earnings (or losses) shall continue to be recognized in accordance with the Investment Options that continue to be made available under the Plan) and each Participant's benefits shall be paid in accordance with the otherwise applicable terms of the Plan.

10.10 Plan to Comply with Code Section 409A. Notwithstanding any provision to the contrary in this Plan, each provision of this Plan shall be interpreted to permit deferrals of Excess Compensation and the payment of deferred amounts in accordance with Code Section 409A and any provision that would conflict with such requirements shall not be valid or enforceable.

SECTION 11. EXECUTION

IN WITNESS WHEREOF, as approved by the Board of Directors of the Corporation on November 25, 2014, the Corporation has caused this SCANA Corporation Executive Deferred Compensation Plan to be executed by its duly authorized officer this 9th day of January, 2015, to be effective as of the dates specified herein.

SCANA Corporation

By: /s/Marty K. Phalen

Title: Senior Vice President - SCANA Admin.

ATTEST:

/s/Gina Champion
Secretary

Exhibit 10.05

SCANA CORPORATION

DIRECTOR COMPENSATION AND DEFERRAL PLAN

(including amendments through November 30, 2014)

SCANA CORPORATION

DIRECTOR COMPENSATION AND DEFERRAL PLAN

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SCANA CORPORATION

DIRECTOR COMPENSATION AND DEFERRAL PLAN

SECTION 1. ESTABLISHMENT AND PURPOSE

1.1 Establishment of the Plan. SCANA Corporation (the "Company") established the SCANA Corporation Nonemployee Director Stock Plan, effective as of January 1, 1997. Effective as of January 1, 2001, the plan was renamed the "SCANA Corporation Director Compensation and Deferral Plan" (hereinafter called the "Plan") and amended and restated to include a deferred compensation component. Effective as of January 1, 2009, the Plan was amended and restated to comply with the requirements of Code Section 409A. Effective as of December 31, 2009, the Plan was again amended and restated to reflect further modifications to comply with Code Section 409A as well as to implement certain design changes. Effective as of April 21, 2011, the Plan was again amended and restated. The Plan was most recently amended and restated as provided herein, effective as of November 30, 2014.

1.2 Purpose of the Plan. The purpose of the Plan is to promote the achievement of long-term objectives of the Company by linking the personal interests of Nonemployee Directors, as defined in Section 2(r) herein, to those of the Company's shareholders and to attract and retain Nonemployee Directors of outstanding competence by mandating that a certain portion as may be determined from time to time of the Retainer Fee of each Participant as defined in Section 2(u) herein, be paid in Company Stock, unless such amount is voluntarily deferred to a future date in accordance with the Plan's terms or pursuant to the SCANA Corporation Executive Deferred Compensation Plan ("EDCP"). The Plan is intended to conform to the provisions of Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any replacement rule in effect from time to time ("Rule 16b-3"). The Plan also provides a means by which Nonemployee Directors may defer certain additional amounts to some future period.

SECTION 2. DEFINITIONS

2.1 Definitions. Whenever used herein, the following terms shall have the meanings set forth below, unless otherwise expressly provided herein or unless a different meaning is plainly required by the context, and when the defined meaning is intended, the term is capitalized:

(a) "Act" means the Securities Exchange Act of 1934, as amended.

(b) "Beneficial Owner" shall have the meaning ascribed to such term in Rule 13d-3 of the General Rules and Regulations under the Act.

(c) "Beneficiary" means any person or entity who, upon the Participant's death, is entitled to receive the Participant's benefits under the Plan in accordance with Section 7 hereof.

(d) "Board of Directors" means the board of directors of the Company.

(e) "Change in Control" means a change in control of the Company of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Act, whether or not the Company is then subject to such reporting requirements; provided that, without limitation, such a Change in Control shall be deemed to have occurred if:

(i) Any Person (as defined in Section 3(a)(9) of the Act and used in Sections 13(d) and 14(d) thereof, including a "group" as defined in Section 13(d)) is or becomes the Beneficial Owner, directly or indirectly, of twenty-five percent (25%) or more of the combined voting power of the outstanding shares of capital stock of the Company;

(ii) During any period of two (2) consecutive years (not including any period prior to the execution of this Plan) there shall cease to be a majority of the Board of Directors comprised as follows: individuals who at the beginning of such period constitute the Board of Directors and any new director(s) whose election by the Board of Directors or nomination for election by the Company's stockholders was approved by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of the period or whose election or nomination for election was previously so approved; or

(iii) The consummation of a merger or consolidation of the Company with any other corporation, other than a merger or consolidation which would result in the voting shares of capital stock of the Company outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting shares of capital stock of the surviving entity) at least eighty percent (80%) of the combined voting power of the voting shares of capital stock of the Company or such surviving entity outstanding immediately after such merger or consolidation; or the shareholders of the Company approve a plan of complete liquidation of the

Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets.

(f)"Code" means the Internal Revenue Code of 1986, as amended.

(g) "Company" means SCANA Corporation, a South Carolina corporation, or any successor thereto.

(h) "Company Stock" means the no par value common stock of the Company. In the event of a change in the capital structure of the Company (as provided in Section 3.6), the shares resulting from such a change shall be deemed to be Company Stock within the meaning of the Plan.

(i) "Company Stock Ledger" means an appropriate bookkeeping record established in the DCD Ledger for which amounts credited are converted into hypothetical credited shares of Company Stock.

(j) "Compensation" means Retainer Fees payable to a Participant during a Service Period by the Company.

(k) "DCD Ledger" means an appropriate bookkeeping record which shall be established for each Participant which shall reflect: (1) the amounts deferred on behalf of each Participant; and (2) the crediting of deemed investments (and hypothetical earnings on those deemed investments) with respect to amounts deferred on behalf of each Participant. Each DCD Ledger shall separately reflect the pre-2005 and post-2004 deferrals and hypothetical earnings thereon, and the portion of the post-2004 deferrals and hypothetical earnings thereon payable at a date certain and the portion payable when the Participant separates from service from the Board of Directors (referred to herein as a Participant's "pre-2005 DCD Ledger" and "post-2004 DCD Ledger"). A Participant's pre-2005 DCD Ledger shall reflect amounts deferred hereunder before January 1, 2005 (and the earnings credited thereon before, on or after January 1, 2005) for which (i) the Participant had a legally binding right as of December 31, 2004, to be paid the amount, and (ii) such right to the amount was earned and vested as of December 31, 2004 and was credited to the Participant's DCD Ledger hereunder. Pre-2005 DCD Ledgers are treated as "grandfathered" for the purposes of Code Section 409A, and are governed by the terms of the Plan in effect as of October 3, 2004.

(l) "Director" means an individual who is a member of the Board of Directors.

(m) "EDCP" means the SCANA Corporation Executive Deferred Compensation Plan.

(n) "Fair Market Value" of Company Stock shall mean:

(i) in the case of any distribution, the closing price for shares of Company Stock on the New York Stock Exchange on the date of distribution; and

(ii) in the case of any other transaction hereunder designed to track the investment or reinvestment of Company Stock, the closing price for shares of Company Stock on the New York Stock Exchange on the measuring date.

(o) "Growth Increment" means the amount of interest credited to amounts credited to a Participant's Growth Increment Ledger.

(p) "Growth Increment Ledger" means an appropriate bookkeeping record established in the DCD Ledger for which amounts are credited with Growth Increments.

(q) "Investor Plan" means the SCANA Investor Plus Plan.

(r) "Nonemployee Director" means a Director who is not currently employed by the Company or any subsidiary of the Company (without regard to whether such individual was previously employed by the Company).

(s) "Participant" means a Nonemployee Director satisfying the eligibility requirements of Section 3.

(t) "Plan" means the SCANA Corporation Director Compensation and Deferral Plan.

(u) "Retainer Fees" means the amount of compensation payable to each Participant with respect to services rendered to the Company as a Director for the Service Period. Such term includes annual leadership retainer fees payable to the Lead Director, Audit Committee Chair, Compensation Committee Chair, Nominating and Governance Committee Chair, Nuclear Oversight Committee Chair or any other retainer fee as determined by the Company or its delegate from time to time.

(v) "Rule 16b-3" means Rule 16b-3 of the Act, as amended, or any replacement rule in effect from time to time.

(w) "Service Period" means a calendar year.

2.2 Gender and Number. Except when otherwise indicated by the context, any masculine terminology used herein also shall include the feminine and the feminine shall include the masculine, and the use of any term herein in the singular may also include the plural and the plural shall include the singular.

SECTION 3. ELIGIBILITY AND PARTICIPATION

3.1Eligibility. All Nonemployee Directors shall automatically be eligible to participate in this Plan.

3.2Election of Compensation Payment.

(a) Unless otherwise deferred in accordance with Section 4 or under the EDCP, each Participant's Retainer Fee amounts shall be paid to the Participant on a quarterly basis and such payment shall be made in shares of Company Stock or cash, as determined by the Company or its delegate. The portion of the Retainer Fee payment that is made in shares of Company Stock is referred to as the "Stock Retainer Fee" and the portion of the Retainer Fee payment that is made in cash is referred to as the "Cash Retainer Fee." Notwithstanding anything to the contrary in this Plan, if a Participant elects to defer all or a portion of his Retainer Fee under the EDCP and in accordance with the terms of the EDCP, the Company or its delegate shall designate a portion of the Retainer Fee as the "Stock Retainer Fee" and a portion of the Retainer Fee as the "Cash Retainer Fee," but no actual payment of shares of Company Stock shall be paid to such Participant and the terms of the EDCP will apply with respect to such deferred amounts.

(b) With respect to all payments in Company Stock under this Section 3.2, and subject to Section 3.3, each Participant shall be entitled to a number of shares of Company Stock equal to the smallest number of whole shares of Company Stock which, when multiplied by Fair Market Value would equal no less than the equivalent amount of Compensation otherwise payable to the Participant. Any remaining amounts owed shall be deposited into an account in the Participant's name in the Investor Plan.

3.3Payment of Company Stock. In connection with amounts to be paid during a Service Period under Section 3.2 which are paid in the form of Company Stock, each Participant may elect to have the shares of Company Stock to be issued to him pursuant to the Plan during the Service Period registered in his name. In such case, all shares of Company Stock to be paid shall be issued as promptly as practicable after the amounts are otherwise payable. If a Participant does not make such an election, all shares issued pursuant to the Plan during the Service Period will be deposited into an account in his name in the Investor Plan. All cash dividends paid on shares deposited in the Investor Plan will be reinvested in additional shares of Company Stock unless the Participant notifies the Investor Plan in accordance with the terms thereof that he does not want to reinvest such dividends. During the last quarter of each calendar year in which there is a change in the prospectus for the Investor Plan, all Participants who have not been provided previously with a copy of such changed prospectus shall be provided with a copy of the then-current prospectus. In addition, each Participant who is not yet a participant in the Investor Plan shall be given an Investor Plan prospectus shortly before he becomes an Investor Plan participant.

3.4Stock. Company Stock issued pursuant to the Plan may be either original issue or stock purchased on the open market. The maximum number of shares that may be issued pursuant to the Plan is four hundred thousand (400,000) shares, subject to adjustment as provided in

Section 3.6. In the event of a change in the capital structure of the Company (as provided in Section 3.6), the shares resulting from such change shall be deemed to be Company Stock within the meaning of the Plan. The aggregate number of shares of Company Stock reserved for issuance pursuant to the Plan shall be reduced by the issuance of shares under the Plan.

3.5 Issuance of Company Stock. Notwithstanding anything in this Plan to the contrary:

(a) The Company shall not be required to issue or deliver any certificate for shares of Company Stock to a Participant before (i) such shares have been admitted to listing on the New York Stock Exchange, (ii) the Company has received any required registration or other qualification of such shares under any state or federal law or regulation that the Company's counsel shall determine is necessary or advisable and (iii) the Company is satisfied that all applicable legal requirements have been complied with. The Company may place on a certificate representing Company Stock any legend deemed necessary by the Company's counsel to comply with federal or state securities laws. Until the Participant has been issued a certificate for the shares of Company Stock acquired, the Participant shall possess no shareholder rights with respect to the shares.

(b) If at any time there may not be sufficient shares available under the Plan to permit the awards of Company Stock, the awards shall be reduced pro rata (to zero, if necessary) so as not to exceed the number of shares then available for issuance under the Plan.

3.6 Effect of Stock Dividends and Other Changes in Capital Structure. Appropriate adjustments shall be made automatically to the number and kind of shares to be issued under the Plan, as well as to any deferred amounts credited to a Participant's Company Stock Ledger and any other relevant provisions of the Plan, if there are any changes in the Company Stock by reason of a stock dividend, stock split, combination of shares, spin-off, reclassification, recapitalization, merger, consolidation or other change in the Company's capital stock (including, but not limited to, the creation or issuance to shareholders generally of rights, options, or warrants for the purchase of common stock or preferred stock of the Company). If the adjustment would produce fractional shares, the fractional shares shall be eliminated by rounding to the nearest whole share. Any adjustments shall be made in a manner consistent with Rule 16b-3. Any such adjustments shall neither enhance nor diminish the rights of a Participant and the Company shall pay all costs of administering the Plan, including all commissions with respect to open market purchases.

SECTION 4. ELECTION TO DEFER

4.1 Deferral Election. Subject to the conditions set forth in this Plan, and such procedures established by the Company, a Participant may elect to defer amounts of Compensation under this Plan, which amounts are not otherwise deferred by such Participant under the EDCP, as follows:

(a) At a time decided by the Company before the beginning of each Service Period, a Participant irrevocably may elect, by written notice to the Company's Secretary (or his designee), to defer a portion of his Compensation earned for such Service Period. In the case of a Participant elected to the Board of Directors during the Service Period, the Participant may elect, within 30 days of his election to the Board of Directors, to defer a portion of his Compensation for services to be performed subsequent to his election. Such election shall specify whether:

(i) the Participant elects to defer all or a portion of his Stock Retainer Fee and acknowledges that all such deferrals shall be credited to the Company Stock Ledger on his behalf; and

(ii) the Participant elects to defer all or a portion of his Cash Retainer Fee and designates what portions of all such deferrals shall be credited on his behalf to either the Growth Increment Ledger or the Company Stock Ledger;

provided, however, that once any portion of a Participant's Compensation is deferred and credited to the Company Stock Ledger as provided herein, that portion of Compensation may not subsequently be credited to the Growth Increment Ledger, and once any portion of a Participant's Compensation is deferred and credited to the Growth Increment Ledger as provided herein, that portion of Compensation may not subsequently be credited to the Company Stock Ledger.

(b) The deferral election specified in Section 4.1(a) above shall be applied to the Participant's Compensation for each Service Period (or the portion of the Service Period, as applicable) to which the deferral election applies. Any deferral election shall remain in effect for future Service Periods unless affirmatively changed in writing by the Participant and received by the Corporate Secretary by the time established for such purpose prior to the beginning of the Service Period for which the change is effective.

(c) If a Participant makes a deferral election under Section 4.1(a) whereby amounts are credited to the Company Stock Ledger on his behalf, dividends attributable to shares of Company Stock credited to his Company Stock Ledger shall be automatically deferred and deemed reinvested pursuant to Section 5.3.

4.2 Deferral Period. With respect to deferrals under this Plan made in accordance with Section 4.1, each Participant must elect a deferral period for each annual deferral. Subject to the additional deferral provisions of Section 4.3 and the acceleration provisions of Section 6.4, any post-2004 deferral may be until the earlier of (i) the Participant's separation from service from the Board of Directors for any reason or (ii) a date certain, subject to any limitations that the Company (or its delegate) in its discretion may choose to apply at the time of the deferral election. All post-2004 deferrals to a date certain must be to the same date certain. In the absence of an election to the contrary by the Participant for amounts deferred hereunder for any deferral period, such deferrals shall be paid in a lump sum payment as soon as practicable after the Participant's separation from service from the Board of Directors for any reason.

4.3 Election to Defer a Previously Deferred Amount or Change the Manner of Payment.

(a) Subject to the acceleration provisions of Section 6.4 and the Board of Directors approval requirement of Section 4.3(b) with respect to pre-2005 deferrals, a Participant may elect an additional deferral period of at least sixty (60) months with respect to any previously deferred amount credited to the post-2004 DCD Ledger that is payable at a date certain, and an additional deferral period of at least twelve (12) months for each separate deferral credited to the pre-2005 DCD Ledger. With respect to amounts deferred until separation from service from the Board of Directors, Participants may also elect a new manner of payment permitted under Section 6.2 with respect to any previously deferred amounts, provided that in the case of amounts credited to post-2004 DCD Ledgers that are payable on separation from service from the Board of Directors, payments are delayed for sixty (60) months from the date payments would otherwise have commenced absent the election. Any such election must be made by written notice to the Company (or its delegate) at least twelve (12) months before the expiration of the deferral period for any previously deferred amount with respect to which an additional deferral election is made (the "Modification Period").

(b) A new deferral period election or a new form of payment election made pursuant to Subsection 4.3(a) above with respect to pre-2005 DCD Ledgers shall not be automatically binding upon the Company by the mere fact of the election request(s) having been made. The Board of Directors (or its delegate) shall review each such election submitted and determine whether or not it is in the best interest of the Company to accept the elections as submitted. Such Board of Directors (or delegate) review will be made on a case-by-case basis and all determinations shall be made by the Board of Directors (or its delegate) in its sole and complete discretion after consideration of such factors as it deems relevant, including broad economic and policy implications to the Company of approving any request. The Board of Directors, or its delegate, shall notify each Participant in writing within the first sixty (60) days of the Modification Period as to whether the deferral period election or manner of payment election with respect to pre-2005 DCD Ledgers are accepted by the Company as submitted, and if not, the terms upon which such election(s) would be accepted; in the latter instance, the Participant shall, no later than on the seventy-fifth (75th) day of the Modification Period, inform the Board of Directors (or its delegate) in writing of his acceptance or rejection of the terms proffered by the

Company (or its delegate). All determinations made by the Board of Directors or its delegate shall be final and binding on all parties.

4.4Election to Change the Deferral Period and/or Form of Payment for Post-2004 DCD Ledgers.

Notwithstanding Section 4.3(a), a Participant may elect at any time prior to January 1, 2009 to change the deferral period (accelerate or defer) and/or method of payment with respect to any post-2004 DCD Ledger that is not scheduled for payment in 2008 by making written notice to the Board of Directors (or its delegates), provided such change does not cause any amounts to be paid in 2008 or cause any amounts otherwise payable in 2008 to be deferred to a later year. Any new deferral period and/or method of payment shall be subject to the requirements of Section 6.

SECTION 5. CREDITING AND INVESTMENT OF DEFERRALS

5.1DCD Ledger. The Company shall establish for each Participant a DCD Ledger which shall reflect the amounts deferred on behalf of each Participant. In the sole discretion of the Company, one or more appropriate bookkeeping records shall be established in the DCD Ledger to reflect the deemed investments (and hypothetical earnings) made by each Participant in accordance with this Section 5 which shall include, but not be limited to, the Company Stock Ledger and the Growth Increment Ledger. Each DCD Ledger shall separately reflect the pre-2005 and post-2004 deferrals and hypothetical earnings thereon, and the portion of the post-2004 deferrals and hypothetical earnings thereon payable at a date certain and the portion payable when the Participant separates from service from the Board of Directors.

5.2Adjustment of Amounts Credited to Growth Increment Ledger. All deferrals credited to each Participant's Growth Increment Ledger will be credited with Growth Increments based on the prime interest rate charged from time to time by the Wachovia Bank, N.A. The Company will have the authority to change the interest rate that may be applied to the Growth Increment Ledger. The Participant's Growth Increment Ledger shall be credited on the first day of each calendar quarter, with a Growth Increment computed on the average balance in the Participant's Growth Increment Ledger during the preceding calendar quarter. The Growth Increment shall be equal to the amount in said Growth Increment Ledger multiplied by the average interest rate selected by the Company during the preceding calendar quarter times a fraction the numerator of which is the number of days during such quarter and the denominator of which is three hundred sixty five (365). Growth Increments will continue to be credited until all of a Participant's benefits have been paid out of the Plan.

5.3Adjustment of Amounts Credited to Company Stock Ledger. All deferrals credited to each Participant's Company Stock Ledger will be converted into hypothetical credited shares of Company Stock based on the Fair Market Value of the Company Stock on the date the deferrals would otherwise have been paid to the Participant. The value of each Participant's Company Stock Ledger shall be adjusted from time to time to reflect increases and decreases in shares of Company Stock as well as any stock or cash dividends, stock splits, or other changes in the capital structure of the Company (as provided in Section 3.6), that may from time to time be declared. All dividends attributable to hypothetical shares of Company Stock credited to each Participant's Company Stock Ledger shall be converted to additional credited shares of Company Stock as though reinvested as of the next business day after the dividend is paid.

5.4Deemed Investments Not Actual Investments. Nothing in this Plan shall be construed to require the investment of any deferrals in shares of Company Stock or any other investment or give a Participant any rights whatsoever with respect to any shares of Company Stock or with respect to any other investment.

5.5Charges Against DCD Ledger. There shall be charged against each Participant's DCD Ledger any payments made to the Participant or to his Beneficiary in accordance with Section 6 hereof.

SECTION 6. PAYMENT OF DEFERRED AMOUNTS

6.1Payment of Deferred Amounts. The aggregate amounts payable under Section 6.2 as charges against the Participant's amount credited in the DCD Ledger shall be paid commencing with the conclusion of the deferral period selected by the Participant pursuant to Section 4.2, Section 4.3, or Section 4.4 hereof. The payments shall be made in the manner selected by the Participant under Section 6.2 of this Plan.

6.2Manner of Payment. Amounts credited to post-2004 DCD Ledgers that are scheduled to be paid at a "date certain" payment shall be made only in the form of a single sum payment as soon as practicable after the date certain. With respect to amounts credited to pre-2005 DCD Ledgers, and amounts credited to post-2004 DCD Ledgers that are scheduled to be paid on separation from service from the Board of Directors, Participants must irrevocably elect (subject to permitted changes under Section 4.3 and the acceleration provisions of Section 6.4) to have payment made in accordance with one of the following distribution forms:

(i)a single sum payment;

(ii)a designated number of installments payable monthly, quarterly or annually, as elected (and in the absence of an election, annually), payable over a specified period not in excess of twenty (20) years; or

(iii)in the case of a post-2004 DCD Ledger, payments in the form of annual installments with the first installment being a single sum payment of ten percent (10%) of the post-2004 DCD Ledger determined immediately prior to the date such payment is made with the balance of the post-2004 DCD Ledger paid in annual installments determined in accordance with Section 6.3 over a total specified period not in excess of twenty (20) years,

which shall be paid or commence to be paid as soon as practicable after the conclusion of the deferral period elected pursuant to Section 4.2 or Section 4.3. Any such election shall be made at the same time as the election made pursuant Section 4.1. Unless otherwise specifically elected, payments of all deferred amounts will be made in a single sum payment made as soon as practicable after the conclusion of the deferral period elected pursuant to Section 4.2 or Section 4.3. If a Participant elects an installment form of payment but fails to specify between the installment form under Section 6.2(ii) or the installment form under Section 6.2(iii), the Participant's benefit will be paid in the installment form under Section 6.2(ii).

6.3Form of Payment. Amounts credited to a Participant's Growth Increment Ledger and Company Stock Ledger shall be paid as follows:

(a)Amounts credited to the Participant's Growth Increment Ledger shall be paid in cash. If a Participant's benefit hereunder is to be paid in installments, the amount of each payment shall be equal to the amount credited to the Participant's Growth Increment

Ledger at the time of payment multiplied by a fraction, the numerator of which is one and the denominator of which is the number of installment payments remaining.

(b)Amounts credited to the Participant's Company Stock Ledger shall be paid in shares of Company Stock with any amount representing a partial share of Company Stock deposited into an account in the Participant's name in the Investor Plan. A payment of an amount credited to the Participant's Company Stock Ledger shall be converted into actual shares of Company Stock as soon as practicable prior to each payment being made to the Participant. If a Participant's benefit hereunder is to be paid in installments, the amount of each payment shall be equal to the number of shares of Company Stock then credited to the Participant's Company Stock Ledger multiplied by a fraction, the numerator of which is one and the denominator of which is the number of installment payments remaining. Any amounts attributable to a partial share of Company Stock as of any installment payment date shall be deposited into an account in the Participant's name in the Investor Plan with each installment.

6.4Acceleration of Payments. Notwithstanding the election made pursuant to Section 4.2, Section 4.3, or Section 4.4,

(a)payments shall be paid, or begin to be paid, as soon as practicable following the Participant's separation from service from the Board of Directors for any reason except as otherwise provided herein;

(b)if a Participant dies prior to the payment of all or a portion of the amounts credited to his DCD Ledger, the balance of any amount payable shall be paid in a cash lump sum to the Beneficiaries designated under Section 7 hereof;

(c)if a Participant ceases to be a Nonemployee Director but thereafter becomes an employee of the Company (or any of its subsidiaries or affiliates), all pre-2005 DCD Ledgers shall be paid as soon as practicable after such individual becomes an employee of the Company (or any of its subsidiaries or affiliates) in a single sum payment and all post-2004 DCD Ledgers shall be paid as soon as practicable after such individual has incurred a separation from service as a Nonemployee Director (as determined in accordance with Code Section 409A);

(d)if a Participant's post-2004 DCD Ledger balance is less than one hundred thousand dollars ($100,000) (five thousand dollars ($5,000) for pre-2005 DCD Ledgers) at the time for payment specified, such amount shall be paid in a single sum payment; and

(e)if applicable, the provisions of Section 8 shall apply.

Notwithstanding Section 6.4(a), in the case of any post-2004 DCD Ledgers that are payable on separation from service from the Board of Directors and that are subject to an additional deferral period of sixty (60) months under Section 4.3(a) as a result of the modification of the manner of payment, no payment attributable to any post-2004 DCD Ledgers shall be accelerated under Section 6.4(a) to a date earlier than the expiration of the sixty (60) month period.

6.5Financial Emergency. The Company (or its delegate), at its sole discretion, may alter the timing or manner of payment of deferred amounts if the Participant establishes, to the satisfaction of the Company (or its delegate), an unanticipated and severe financial hardship that is caused by an event beyond the Participant's control. In such event, the Company (or its delegate) may:

(a)provide that all, or a portion of, the amount previously deferred by the Participant immediately shall be paid in a lump sum cash payment,

(b)provide that all, or a portion of, the installments payable over a period of time immediately shall be paid in a lump sum cash payment, or

(c)provide for such other installment payment schedules as it deems appropriate under the circumstances,

as long as the amount distributed shall not be in excess of that amount which is necessary for the Participant to satisfy the financial emergency. For pre-2005 DCD Ledgers, severe financial hardship will be deemed to have occurred in the event of the Participant's or a dependent's sudden, lengthy and serious illness as to which considerable medical expenses are not covered by insurance or relative to which there results a significant loss of family income, or other unanticipated events of similar magnitude. For post-2004 DCD Ledgers, severe financial hardship will be deemed to have occurred from a sudden or unexpected illness or accident of the Participant or the Participant's spouse, Beneficiary or dependent (as defined in Code Section 152, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)), loss of the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the Participant's control. Examples of events that may constitute an unforeseeable emergency for post-2004 DCD Ledgers include the imminent foreclosure of or eviction from the Participant's primary residence; the need to pay for medical expenses, including non-refundable deductibles, as well as for the costs of prescription drug medication; and the need to pay for the funeral expenses of the Participant's spouse, Beneficiary or dependent (as defined in Code Section 152, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)). The circumstances that will constitute an unforeseeable emergency will depend upon the facts of each case, but, in any case, payment may not be made to the extent that such hardship is or may be relieved through reimbursement or compensation by insurance or otherwise, by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship, or by cessation of deferrals under the Plan. Examples of circumstances that are not considered to be unforeseeable emergencies include the need to send a Participant's child to college or the desire to purchase a home. The Company's decision (or that of its delegate) in passing on the severe financial hardship of the Participant and the manner in which, if at all, the payment of deferred amounts shall be altered or modified shall be final, conclusive, and not subject to appeal. The Company shall consider any requests for payment under this Section 6.5 in accordance with the standards of interpretation described in Code Section 409A and the regulations and other guidance thereunder.

6.6 Compliance with Domestic Relations Order. Notwithstanding anything to the contrary in this Plan, a distribution shall be made from the Participant's DCD Ledgers to an individual other than the Participant to the extent necessary to comply with a domestic relations order (as defined in Code Section 414(p)(1)(B)).

SECTION 7. BENEFICIARY DESIGNATION

7.1 Designation of Beneficiary. A Participant shall designate a Beneficiary or Beneficiaries who, upon the Participant's death, are to receive the amounts that otherwise would have been paid to the Participant. All designations shall be in writing and signed by the Participant. The designation shall be effective only if and when delivered to the Company during the lifetime of the Participant. The Participant also may change his Beneficiary or Beneficiaries by a signed, written instrument delivered to the Company. The payment of amounts shall be in accordance with the last unrevoked written designation of Beneficiary that has been signed and delivered to the Company. All Beneficiary designations shall be addressed to the Company's Secretary and delivered to his office.

7.2 Death of Beneficiary.

(a) In the event that all of the Beneficiaries named pursuant to Section 7.1 predecease the Participant, the amounts that otherwise would have been paid to said Beneficiaries shall, where the designation fails to redirect to alternate Beneficiaries in such circumstance, be paid to the Participant's estate as the alternate Beneficiary.

(b) In the event that two or more Beneficiaries are named, and one or more but less than all of such Beneficiaries predecease the Participant, each surviving Beneficiary shall receive any proportion or amount of funds designated or indicated for him per the designation under Section 7.1, and the indicated share of each predeceased Beneficiary which the designation fails to redirect to an alternate Beneficiary in such circumstance shall be paid to the Participant's estate as an alternate Beneficiary.

7.3 Ineffective Designation.

(a) In the event the Participant does not designate a Beneficiary, or if for any reason such designation is entirely ineffective, the amounts that otherwise would have been paid to the Beneficiary shall be paid to the Participant's estate as the alternate Beneficiary.

(b) In the circumstance that designations are effective in part and ineffective in part, to the extent that a designation is effective, distribution shall be made so as to carry out as closely as discernable the intent of the Participant, with the result that only to the extent that a designation is ineffective shall distribution instead be made to the Participant's estate as an alternate Beneficiary.

SECTION 8. CHANGE IN CONTROL PROVISIONS

8.1 Successors. Notwithstanding anything in this Plan to the contrary, upon the occurrence of a Change in Control, the Company will require any successor (whether direct or indirect, by purchase, merger, consolidation, or otherwise) of all or substantially all of the business and/or assets of the Company or of any division or subsidiary thereof to expressly assume and agree to perform this Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place, subject to the remaining provisions of this Section 8.1. Participants shall become entitled to benefits hereunder in accordance with the terms of this Plan, based on amounts credited to each Participant's DCD Ledger as of the date of such Change in Control plus accumulated Growth Increments attributable thereto (adjusted to reflect any change from the most recent Growth Increment calculation to the end of the month prior to the month such amounts are distributed to each Participant). In such case, any successor to the Company shall not be required to provide for additional deferral of benefits beyond the date of such Change in Control except as required under Code Section 409A.

8.2 Amendment and Termination After Change in Control. Notwithstanding the foregoing, and subject to this Section 8, no amendment, modification or termination of the Plan may be made, and no Participants may be added to the Plan, upon or following a Change in Control if it would have the effect of reducing any benefits earned (including optional forms of distribution) prior to such Change in Control without the written consent of all of the Plan's Participants covered by the Plan at such time. In all events, however, the Company reserves the right to amend, modify or delete the provisions of Section 8 at any time prior to a Change in Control, pursuant to a Board of Directors resolution adopted by a vote of two-thirds (2/3) of the Board of Directors members then serving on the Board of Directors.

SECTION 9. GENERAL PROVISIONS

9.1 Contractual Obligation. It is intended that the Company is under a contractual obligation to make payments from a Participant's DCD Ledger when due. Payment of amounts credited to a Participant's DCD Ledger shall be made out of the general funds of the Company as determined by the Board of Directors without any restriction of the assets of the Company relative to the payment of such contractual obligations; the Plan is, and shall operate as, an unfunded plan.

9.2 Unsecured Interest. No Participant or Beneficiary shall have any interest whatsoever in any specific asset of the Company. To the extent that any person acquires a right to receive payment under this Plan, such right shall be no greater than the right of any unsecured general creditor of the Company.

9.3 "Rabbi" Trust. In connection with this Plan, the Company shall establish a grantor trust (known as the "SCANA Corporation Director Compensation Trust" and referred to herein as the "Trust") for the purpose of accumulating funds to satisfy the obligations incurred by the Company under this Plan (and such other plans and arrangements as determined from time to time by the Company). At any time prior to a Change in Control, as that term is defined in such Trust, the Company may transfer assets to the Trust to satisfy all or part of the obligations incurred by the Company under this Plan, as determined in the sole discretion of the Board of Directors, subject to the return of such assets to the Company at such time as determined in accordance with the terms of such Trust. Any assets of such Trust shall remain at all times subject to the claims of creditors of the Company in the event of the Company's insolvency; and no asset or other funding medium used to pay benefits accrued under the Plan shall result in the Plan being considered as other than "unfunded" under ERISA. Notwithstanding the establishment of the Trust, the right of any Participant to receive future payments under the Plan shall remain an unsecured claim against the general assets of the Company.

9.4 Nonalienation of Benefits.

(a) Subject to Section 6.6, no right or benefit under this Plan shall be subject to anticipation, alienation, sale, assignment, pledge, encumbrance, or charge, and any attempt to anticipate, alienate, sell, assign, pledge, encumber or charge the same shall be void; nor shall any such disposition be compelled by operation of law.

(b) No right or benefit hereunder shall in any manner be liable for or subject to the debts, contracts, liabilities, or torts of the person entitled to benefits under the Plan.

(c) If any Participant or Beneficiary hereunder should become bankrupt or attempt to anticipate, alienate, sell, assign, pledge, encumber, or charge any right or benefit hereunder (other than as permitted in Section 6.6), then such right or benefit shall, in the discretion of the Board of Directors, cease, and the Board of Directors shall direct in such event that the Company hold or apply the same or any part thereof for the benefit of the Participant or Beneficiary in such manner and in such proportion as the Board of Directors may deem proper.

9.5Severability. If any particular provision of the Plan shall be found to be illegal or unenforceable for any reason, the illegality or lack of enforceability of such provision shall not affect the remaining provisions of the Plan, and the Plan shall be construed and enforced as if the illegal or unenforceable provision had not been included.

9.6No Individual Liability. It is declared to be the express purpose and intention of the Plan that no liability whatsoever shall attach to or be incurred by the shareholders, officers, or directors of the Company or any representative appointed hereunder by the Company, under or by reason of any of the terms or conditions of the Plan.

9.7Applicable Law. This Plan shall be governed and construed in accordance with the laws of the State of South Carolina except to the extent governed by applicable Federal law (including the requirements of Code Section 409A). The terms of this Plan are also subject to all present and future rulings of the Securities and Exchange Commission with respect to Rule 16b-3. If any provision of the Plan would cause the Plan to fail to meet the requirements of Rule 16b-3, then that provision of the Plan shall be void and of no effect.

SECTION 10. PLAN ADMINISTRATION, AMENDMENT AND TERMINATION

10.1 In General. This Plan shall be administered by the Company, which shall have the sole authority to construe and interpret the terms and provisions of the Plan and determine the amount, manner and time of payment of any benefits hereunder. The Company shall not exercise any discretion with respect to the administration of this Plan, except as may be permitted by Rule 16b-3. The Company shall maintain records, make the requisite calculations and disburse payments hereunder, and its interpretations, determinations, regulations and calculations shall be final and binding on all persons and parties concerned. The Company may adopt such rules as it deems necessary, desirable or appropriate in administering this Plan.

10.2 Claims Procedure. Any person dissatisfied with the Company's determination of a claim for benefits hereunder must file a written request for reconsideration with the Company (or its delegate). This request must include a written explanation setting forth the specific reasons for such reconsideration. The Company shall review its determination promptly and render a written decision with respect to the claim, setting forth the specific reasons for such denial written in a manner calculated to be understood by the claimant. Such claimant shall be given a reasonable time within which to comment, in writing, to the Company with respect to such explanation. The Company shall review its determination promptly and render a written decision with respect to the claim. Such decision upon matters within the scope of the authority of the Company shall be conclusive, binding, and final upon all claimants under this Plan.

10.3 Finality of Determination. The determination of the Company as to any disputed questions arising under this Plan, including questions of construction and interpretation, shall be final, binding, and conclusive upon all persons.

10.4 Delegation of Authority. The Company may, in its discretion, delegate its duties to a committee of the Board of Directors or an officer or other employee of the Company, or to a committee composed of officers or employees of the Company.

10.5 Expenses. The cost of payment from this Plan and the expenses of administering the Plan shall be borne by the Company.

10.6 Tax Withholding. The Company shall have the right to deduct from all payments made from the Plan any federal, state, or local taxes required by law to be withheld with respect to such payments.

10.7 Incompetency. Any person receiving or claiming benefits under the Plan shall be conclusively presumed to be mentally competent and of age until the Company receives written notice, in a form and manner acceptable to it, that such person is incompetent or a minor, and that a guardian, conservator, statutory committee under the South Carolina Code of Laws, or other person legally vested with the care of his estate has been appointed. In the event that the Company finds that any person to whom a benefit is payable under the Plan is unable to properly care for his affairs, or is a minor, then any payment due (unless a prior claim therefor shall have been made by a duly appointed legal representative) may be paid to the spouse, a child, a parent, or a brother or sister, or to any person deemed by the Company to have incurred expense for the care of such person otherwise entitled to payment.

In the event a guardian or conservator or statutory committee of the estate of any person receiving or claiming benefits under the Plan shall be appointed by a court of competent jurisdiction, payments shall be made to such guardian or conservator or statutory committee provided that proper proof of appointment is furnished in a form and manner suitable to the Company. Any payment made under the provisions of this Section 10.7 shall be a complete discharge of liability therefor under the Plan.

10.8Action by Company. Any action required or permitted to be taken hereunder by the Company or its Board of Directors shall be taken by the Board of Directors, or by any person or persons authorized by the Board of Directors.

10.9Notice of Address. Any payment made to a Participant or to his Beneficiary at the last known post office address of the distributee on file with the Company, shall constitute a complete acquittance and discharge to the Company and any director or officer with respect thereto, unless the Company shall have received prior written notice of any change in the condition or status of the distributee. Neither the Company nor any director or officer shall have any duty or obligation to search for or ascertain the whereabouts of the Participant or his Beneficiary.

10.10Amendment and Termination. The Company expects the Plan to be permanent but, since future conditions affecting the Company cannot be anticipated or foreseen, the Company reserves the right to amend, modify, or terminate the Plan at any time by action of its Board of Directors, subject to Section 8.2 and the requirements of Code Section 409A with respect to post-DCD Ledgers, (including, but not limited to, as may be necessary to ensure compliance with Rule 16b-3); provided, however, that any such action shall not diminish retroactively any amounts which have been credited to any Participant's DCD Ledger. If the Board of Directors amends the Plan to cease future deferrals hereunder or terminates the Plan, the Board of Directors may, in its sole discretion, direct that the value of each Participant's DCD Ledger be paid to each Participant (or Beneficiary, if applicable) in an immediate lump sum payment. In the absence of any such direction from the Board of Directors, the Plan shall continue as a "frozen" plan under which no future deferrals will be recognized (however, Growth Increments and dividends attributable to hypothetical shares of Company Stock credited to each Participant's Company Stock Ledger shall continue to be recognized) and each Participant's benefits shall be paid in accordance with the otherwise applicable terms of the Plan.

10.11Plan to Comply with Code Section 409A. Notwithstanding any provision to the contrary in this Plan, each provision of this Plan shall be interpreted to permit Director deferrals and the payment of deferred amounts in accordance with Code Section 409A and any provision that would conflict with such requirements shall not be valid or enforceable.

SECTION 11. EXECUTION

IN WITNESS WHEREOF, the Company has caused this SCANA Corporation Director Compensation and Deferral Plan to be executed by its duly authorized officer to be effective on the 30th day of November, 2014.

SCANA Corporation

By: /s/Marty K. Phalen

Title: Senior Vice President - SCANA Admin.

ATTEST:

/s/Gina Champion
Secretary

Exhibit 12.01

COMPUTATION OF RATIOS
December 31, 2014

BOND RATIO

SCANA and SCE&G:

Dollars in Millions Year Ended December 31, 2014		
Net earnings as defined in SCE&G's bond indenture dated April 1, 1993 (Mortgage)		$ 1,133.0
Divide by annualized interest charges on:		
Bonds outstanding under the Mortgage	$ 209.5	
Total annualized interest charges	209.5	
Bond Ratio		5.41

RATIO OF EARNINGS TO FIXED CHARGES

Dollars in Millions	SCANA					SCE&G				
Years Ended December 31,	2014	2013	2012	2011	2010	2014	2013	2012	2011	2010
Fixed Charges as defined:										
Interest on debt	$318.2	$305.9	$301.3	$287.0	$270.4	$237.6	$226.4	$217.4	$207.8	$192.4
Amortization of debt premium, discount and expense (net)	9.7	5.3	4.9	4.8	5.1	4.4	4.2	3.9	3.9	4.0
Interest component on rentals	4.1	4.9	4.9	5.2	4.6	4.0	4.5	3.2	3.6	3.1
Total Fixed Charges (A)	$332.0	$316.1	$311.1	$297.0	$280.1	$246.0	$235.1	$224.5	$215.3	$199.5
Earnings as defined:										
Pretax income from continuing operations	$786.0	$693.8	$601.6	$555.6	$535.4	$676.0	$579.7	$509.5	$456.5	$433.6
Total fixed charges above	332.0	316.1	311.1	297.0	280.1	246.0	235.1	224.5	215.3	199.5
Pretax equity in (earnings) losses of investees	(1.4)	(3.2)	(3.3)	(2.9)	(1.1)	5.3	3.5	3.8	2.3	2.1
Cash distributions from equity investees	7.4	9.6	3.3	3.6	4.8	-	-	-	-	-
Total Earnings (B)	$1,124.0	$1,016.3	$912.7	$853.3	$819.2	$927.3	$818.3	$737.8	$674.1	$635.2
Ratio of Earnings to Fixed Charges (B/A)	3.39	3.22	2.93	2.87	2.92	3.77	3.48	3.29	3.13	3.18

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-174796 and 333-191691 on Form S-8 and Post-Effective Amendment No. 1 to Registration Statement No. 333-37398 on Form S-8 and Registration Statement Nos. 333-184426 and 333-191756 on Form S-3 of our reports dated February 27, 2015, relating to the consolidated financial statements and financial statement schedule of SCANA Corporation and subsidiaries (the "Company"), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2014.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 27, 2015

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-184426-01 on Form S-3 of our report dated February 27, 2015, relating to the consolidated financial statements and financial statement schedule of South Carolina Electric & Gas Company and affiliates appearing in this Annual Report on Form 10-K of South Carolina Electric & Gas Company for the year ended December 31, 2014.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 27, 2015

Exhibit 24.01

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of SCANA Corporation (“SCANA”), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCANA’s fiscal year ended December 31, 2014, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the “Annual Report”), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 19th day of February 2015.

/s/J. A. Bennett
J. A. Bennett
Director

/s/J. F. A. V. Cecil
J. F. A. V. Cecil
Director

/s/D. M. Hagood
D. M. Hagood
Director

/s/K. B. Marsh
K. B. Marsh
Director

/s/J. M. Micali
J. M. Micali
Director

/s/L. M. Miller
L. M. Miller
Director

/s/J. W. Roquemore
J. W. Roquemore
Director

/s/M. K. Sloan
M. K. Sloan
Director

/s/H. C. Stowe
H. C. Stowe
Director

/s/A. Trujillo
A. Trujillo
Director

Exhibit 24.02

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of South Carolina Electric & Gas Company (“SCE&G”), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCE&G’s fiscal year ended December 31, 2014, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the “Annual Report”), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 19th day of February 2015.

/s/J. A. Bennett	/s/J. F. A. V. Cecil
J. A. Bennett Director	J. F. A. V. Cecil Director
/s/D. M. Hagood	/s/K. B. Marsh
D. M. Hagood Director	K. B. Marsh Director
/s/J. M. Micali	/s/L. M. Miller
J. M. Micali Director	L. M. Miller Director
/s/J. W. Roquemore	/s/M. K. Sloan
J. W. Roquemore Director	M. K. Sloan Director
/s/H. C. Stowe	/s/A. Trujillo
H. C. Stowe Director	A. Trujillo Director

Exhibit 31.01

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

February 27, 2015

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board, President,
Chief Executive Officer and Chief Operating Officer

Exhibit 31.02

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 27, 2015	/s/Jimmy E. Addison
	Jimmy E. Addison
	Executive Vice President and Chief Financial Officer

Exhibit 31.03

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 27, 2015	/s/Kevin B. Marsh
	Kevin B. Marsh, Chairman of the Board and Chief Executive Officer

Exhibit 31.04

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 27, 2015

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 32.01

SCANA CORPORATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the “Company”) on Form 10-K for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes- Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2015

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board, President,
Chief Executive Officer and Chief Operating Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.02

SCANA CORPORATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the “Company”) on Form 10-K for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes- Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2015

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.03

SOUTH CAROLINA ELECTRIC & GAS COMPANY

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of South Carolina Electric & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2015

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board and Chief
Executive Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.04

SOUTH CAROLINA ELECTRIC & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of South Carolina Electric & Gas Company (the “Company”) on Form 10-K for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2015

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

FORM 10-K

SOUTH CAROLINA ELECTRIC & GAS CO - SCG

Filed: February 24, 2017 (period: December 31, 2016)

Annual report with a comprehensive overview of the company

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2016

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	**SCANA Corporation** (a South Carolina corporation)	**57-0784499**
1-3375	**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	**57-0248695**

Securities registered pursuant to Section 12(b) of the Act:
SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $10.8 billion at June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $75.66 per share. South Carolina Electric & Gas Company is a wholly-owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 20, 2017
SCANA Corporation	Without Par Value	142,916,917
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Specified sections of SCANA Corporation's Proxy Statement, in connection with its 2017 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. South Carolina Electric & Gas Company makes no representation as to information relating to SCANA Corporation or its subsidiaries (other than South Carolina Electric & Gas Company and its consolidated affiliates).

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, “forward-looking statements” for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expects,” “forecasts,” “plans,” “anticipates,” “believes,” “estimates,” “projects,” “predicts,” “potential” or “continue” or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;
(2) legislative and regulatory actions, particularly changes related to electric and gas services, rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;
(3) current and future litigation;
(4) changes in the economy, especially in areas served by subsidiaries of SCANA;
(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;
(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;
(7) the loss of sales to distributed generation, such as solar photovoltaic systems or energy storage systems;
(8) growth opportunities for SCANA’s regulated and other subsidiaries;
(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;
(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA’s subsidiaries;
(11) changes in SCANA’s or its subsidiaries’ accounting rules and accounting policies;
(12) payment and performance by counterparties and customers as contracted and when due;
(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission, including nuclear generating facilities;
(14) the results of efforts to operate the Company's electric and gas systems and assets in accordance with acceptable performance standards, including the impact of additional distributed generation and nuclear generation;
(15) maintaining creditworthy joint owners for SCE&G’s new nuclear generation project;
(16) the creditworthiness and/or financial stability of contractors for SCE&G's new nuclear generation project, particularly in light of adverse financial developments disclosed by Toshiba;
(17) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon quality and prices, for our construction program, operations and maintenance;
(18) the results of efforts to ensure the physical and cyber security of key assets and processes;
(19) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;
(20) the availability of skilled, licensed and experienced human resources to properly manage, operate, and grow the Company’s businesses;
(21) labor disputes;
(22) performance of SCANA’s pension plan assets and the effect(s) of associated discount rates;
(23) changes in tax laws and realization of tax benefits and credits, including production tax credits for new nuclear units, and the ability or inability to realize credits and deductions;
(24) inflation or deflation;
(25) changes in interest rates;
(26) compliance with regulations;
(27) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and
(28) the other risks and uncertainties described from time to time in the reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CB&I	Chicago Bridge & Iron Company N.V.
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
CO_2	Carbon Dioxide
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of WEC and Stone and Webster
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker (decoupling mechanism)
CWA	Clean Water Act
DCGT	Dominion Carolina Gas Transmission LLC
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DRB	Dispute Resolution Board
DSM Programs	Demand Side Management Programs
ELG Rule	Federal effluent limitation guidelines for steam electric generating units
EMANI	European Mutual Association for Nuclear Insurance
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fluor	Fluor Corporation
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRC	Internal Revenue Code
IRS	United States Internal Revenue Service
KVA	Kilovolt ampere
kWh	Kilowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability

LNG	Liquefied Natural Gas
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NASDAQ	The NASDAQ Stock Market, Inc.
NAV	Net Asset Value
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NO_X	Nitrogen Oxide
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
ROE	Return on Common Equity
RSA	Natural Gas Rate Stabilization Act
RTO/ISO	Regional Transmission Organization/Independent System Operator
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	SCANA Energy Marketing, Inc.
SCANA Services	SCANA Services, Inc.
SCE&G	South Carolina Electric & Gas Company
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Southern Natural	Southern Natural Gas Company
Spirit Communications	SCTG, LLC and its wholly-owned subsidiary SCTG Communications, Inc.
Stone & Webster	Prior to December 31, 2015, CB&I Stone & Webster, a subsidiary of CB&I. Effective December 31, 2015, Stone & Webster, a subsidiary of WECTEC, LLC, a wholly-owned subsidiary of WEC
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Toshiba	Toshiba Corporation, parent company of WEC
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
Unit 1	Nuclear Unit 1 at Summer Station
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
WEC	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

INVESTOR INFORMATION

SCANA’s and SCE&G’s annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA’s internet website at *www.scana.com* (which is not intended as an active hyperlink; the information on SCANA’s website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC) as soon as reasonably practicable after these reports are filed or furnished.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G’s new nuclear project and other matters of interest to investors on SCANA’s website. On SCANA’s homepage, there is a yellow box containing links to the Nuclear Development and Other Investor Information sections of the website. The Nuclear Development section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor-related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear Development and Other Investor Information yellow box.

CORPORATE STRUCTURE AND SEGMENTS OF BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees of 5,910 as of February 20, 2017 and 5,829 as of February 19, 2016. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries, including the subsidiaries described below.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 709,000 customers and the purchase, sale and transportation of natural gas to approximately 358,000 customers (each as of December 31, 2016). SCE&G’s business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G’s electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a unit power sales agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 550,000 residential, commercial and industrial customers (as of December 31, 2016). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

Nonregulated Businesses

SCANA Energy markets natural gas in the southeast and provides energy-related services. A division of SCANA Energy sells natural gas to approximately 450,000 customers (as of December 31, 2016) in Georgia’s deregulated natural gas market.

SCANA Services, Inc. provides administrative and management services to SCANA's other subsidiaries.

For information with respect to major segments of business, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 12 of the consolidated financial statements. All such information is incorporated herein by reference.

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity and margins earned from those sales by customer classification as percentages of electric revenues were as follows:

	Sales		Margins	
Customer Classification	**2016**	**2015**	**2016**	**2015**
Residential	46%	45%	50%	50%
Commercial	33%	33%	33%	33%
Industrial	17%	17%	14%	14%
Sales for resale	2%	2%	1%	1%
Other	2%	3%	2%	2%
Total	100%	100%	100%	100%

Sales for resale include sales to three municipalities and one electric cooperative. Short-term system sales and margins were not significant for either period presented.

During 2016 SCE&G experienced a net increase of approximately 11,000 electric customers (growth rate of 1.6%), increasing its total number of electric customers to approximately 709,000 at year end.

The following projections assume normal weather where applicable. For the period 2016 to 2017, SCE&G projects a retail kWh sales decrease of approximately 0.1% and customer growth of 1.5%. For the period 2017-2019, SCE&G projects total territorial kWh sales of electricity to increase 0.3% annually, total retail sales to grow 0.3% annually, total electric customer base to increase 1.6% annually and territorial peak load (summer, in MW) to increase 1.6% annually. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%; however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a unit power sales agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system extends over a large part of the central, southern and southwestern portions of South Carolina. The system interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Santee Cooper, Georgia Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) were as follows:

	Cost of Fuel Used		
	2016	2015	2014
Per MMBTU:			
Nuclear	$ 0.98	$ 0.95	$ 1.01
Coal	3.41	3.81	3.90
Natural Gas	3.02	3.26	5.19
All Fuels (weighted average)	2.41	3.01	3.62
Per Ton: Coal	84.62	95.69	96.74
Per MCF: Gas	3.11	3.35	5.30

For a listing of the Company's generating facilities, see the Electric Properties section within Item 2. Properties. For information on actual and projected sources and percentages of total MWh generation by each category of fuel, see Electric Operations - Environmental within the Overview section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

In 2016, coal was primarily obtained through long-term contracts with suppliers located in eastern Kentucky, Tennessee, Virginia, and West Virginia. These contracts provide for approximately 1.4 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2018. Spot market purchases may occur when needed or when prices are believed to be favorable. The Company relies on unit trains and, in some cases, trucks and barges for coal deliveries.

SCANA and SCE&G believe that electric operations comply with all applicable regulations relating to the discharge of SO_2 and NO_X . See additional discussion at Environmental Matters in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G, for itself and as agent for Santee Cooper, and WEC are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G supplies enriched products to WEC and WEC supplies nuclear fuel assemblies for Unit 1 and is under contract to supply assemblies for the New Units. WEC will be SCE&G’s exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Unit 1 and the New Units through 2033. SCE&G is dependent upon WEC for providing fuel assemblies for the new AP1000 reactors in the New Units in the current and anticipated future absence of other commercially viable sources.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of its nuclear generating units.

SCE&G stores spent nuclear fuel in its on-site spent-fuel pool, and has constructed a dry cask storage facility to accommodate the spent fuel output for the life of Unit 1. In addition, Unit 1 has sufficient on-site capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see the Environmental section of Note 10 to the consolidated financial statements.

SCE&G also uses long-term power purchase agreements to ensure that adequate power supply resources are in place to meet load obligations and reserve requirements. As of January 1, 2017, SCE&G had such agreements in place for 325 MW of capacity (expiring at various times through 2020). In addition, SCE&G had the ability to purchase an additional 204 MW of capacity under these agreements.

GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported were as follows:

	SCANA		SCE&G	
Customer Classification	**2016**	**2015**	**2016**	**2015**
Residential	57.9%	57.0%	48.3%	47.9%
Commercial	26.4%	26.8%	28.6%	28.0%
Industrial	10.4%	11.0%	19.5%	20.6%
Transportation Gas	5.3%	5.2%	3.6%	3.5%
Total	100.0%	100.0%	100.0%	100.0%

For the period 2017-2019, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 4.1% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.5%, commercial of 0.8% and industrial of 10.7%.

For the period 2017-2019, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 2.7% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.4%, commercial of 0.7% and industrial of 4.3%.

For the period 2017-2019, each of SCANA's and SCE&G's total regulated natural gas customer base is projected to increase 2.6% annually. During 2016, SCANA recorded a net increase of approximately 26,000 regulated gas customers (growth rate of 2.9%), increasing the number of its regulated gas customers to approximately 907,000. Of this increase, SCE&G recorded a net increase of approximately 10,000 gas customers (growth rate of 2.9%), increasing the number of its total gas customers to approximately 358,000 (as of December 31, 2016).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost and Supply

SCE&G purchases natural gas under contracts with producers and marketers on both a short-term and long-term basis at market based prices. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2018), Transco (expiring at various times through 2031) and DCGT (expiring at various times through 2036). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 212,194 MMBTU from Southern Natural, 104,652 MMBTU from Transco and 461,727 MMBTU from DCGT. Additional natural gas volumes may be delivered to SCE&G's system as capacity is available through interruptible transportation.

The daily volume of gas that SCANA Energy is entitled to transport under its service agreements (expiring at various times through 2023) on a firm basis is 771,627 MMBTU. Additional natural gas volumes may be delivered as capacity is available through interruptible transportation.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $3.46 per MMBTU during 2016 and $3.67 per MMBTU during 2015.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G has 5,502,600 MMBTU of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 3,806,800 MMBTU of gas were in storage on December 31, 2016. SCE&G supplements its supplies of natural gas with two LNG storage facilities, one of which has liquefaction capability. Approximately 1,833,400 MMBTU (liquefied equivalent) of gas were in storage on December 31, 2016. For a discussion of SCE&G's natural gas storage capacity, see Item 2. Properties.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2031. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 710,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $3.73 per MMBTU during 2016 compared to $4.12 per MMBTU during 2015.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, Transco and Spectra Energy provide for storage capacity of approximately 13,000,000 MMBTU. Approximately 9,000,000 MMBTU of gas were in storage under these agreements at December 31, 2016. PSNC Energy also maintains LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG which provides 1,300,000 MMBTU (liquefied equivalent) of storage space. Approximately 1,100,000 MMBTU (liquefied equivalent) were in storage under these agreements at December 31, 2016. Approximately 900,000 MMBTU (liquefied equivalent) of gas were in storage at PSNC Energy's LNG storage facility at December 31, 2016. For a discussion of PSNC Energy's LNG storage capacity, see Item 2. Properties.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SCANA Energy markets natural gas and provides energy-related services in the Southeast. In addition, a division of SCANA Energy markets natural gas to approximately 450,000 customers (as of December 31, 2016) in Georgia’s natural gas market. Georgia’s natural gas market includes approximately 1.6 million customers.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements.

REGULATION

Regulatory jurisdictions to which SCANA and its subsidiaries are subject are described in the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	License Expiration
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

* SCE&G operates the Saluda hydroelectric project under an annual license while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, or may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 2 to the consolidated financial statements.

Fuel Cost Recovery Procedures

The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions, and the cost of emission allowances used for SO_2, NO_X, mercury and particulates. In addition, the statutory definition of fuel cost allows electric utilities to recover avoided costs under the Public Utility Regulatory Policy Act of 1978, as well as costs incurred as a result of offering DER and net metering programs to its customers. SCE&G may request a formal proceeding concerning its fuel costs at any time.

Fuel cost recovery procedures related to the Company's natural gas operations along with related rate proceedings by the SCPSC and NCUC are described in Note 2 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of any new or pending regulations or standards upon existing operations cannot be predicted. For a discussion of how these regulations and standards may impact SCANA and SCE&G (including capital expenditures necessitated thereby), see the Environmental Matters section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements.

OTHER MATTERS

Insurance coverage for SCE&G's nuclear units is described in Note 10 to the consolidated financial statements.

For a discussion of the impact of competition, see the Overview section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to the Company, and where indicated the risk factors also relate to Consolidated SCE&G.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction for environmental compliance and its construction of the New Units and associated transmission infrastructure, are significant and these projects are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of these projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in energy generation and in other internal infrastructure projects, including projects for environmental compliance. In particular, SCE&G and Santee Cooper have agreed to jointly own, contract the design and construction of, and operate the New Units, which will be two 1,250 MW (1,117 MW, net) nuclear units at SCE&G's Summer Station, in pursuit of which they have committed and are continuing to commit significant resources. In addition, construction of significant new transmission infrastructure is necessary to support the New Units and is under way as an integral part of the project. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and construction schedules may be affected by many variables, such as the regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness and/or financial stability, unforeseen difficulties meeting critical regulatory requirements, contract disputes and litigation, and changes in key contractors or subcontractors. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects (including new baseload generation) as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, adverse changes in applicable laws and regulations, new or enhanced environmental or regulatory requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. Some of the foregoing issues have been experienced in the construction of the New Units. A discussion of certain of those matters can be found under New Nuclear Construction in Note 10 to the consolidated financial statements.

Should the construction of the New Units materially and adversely deviate from the SCPSC-approved schedules (by more than 18 months), estimates, and projections, the SCPSC could disallow the additional capital costs that result from the deviations to the extent that it is deemed that the Company's failure to anticipate or avoid the deviation, or to minimize the resulting expenses, was imprudent, considering the information available at the time that the Company could have acted to avoid the deviation or minimize its effect. Depending upon the magnitude of any such disallowed capital costs, the Company could be moved to evaluate the prudency of continuation, adjustment to, or termination of the project.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to risks including that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, that new joint owners cannot be secured at equivalent financial terms, or that changes in the joint ownership make-up will increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows and financial condition, as well as our qualifications for applicable governmental programs and benefits, such as production tax credits, may be adversely affected.

Recent announcements by Toshiba, the parent company of WEC and the guarantor of WEC's payment obligations with respect to the above construction project for New Units at SCE&G's Summer Station, related to deterioration in its financial position and liquidity indicate heightened risks and substantial uncertainties with respect to the cost, timing, construction and/or completion of the New Units.

Following several announcements and related media reports, on February 14, 2017, Toshiba, the parent company of WEC and the guarantor of its payment obligations with respect to the EPC Contract, announced that it expects to record a multi-billion dollar impairment loss associated with the construction of the New Units and the two additional AP1000 units being constructed by WEC for another company in the United States.

In December 2015, WEC acquired 100% of the shares of Stone & Webster from CB&I. On December 27, 2016, Toshiba announced the possibility that the goodwill resulting from the transaction would reach a level of several billion U.S. dollars and would be impaired, leaving Toshiba with negative shareholders' equity. The increase to the amount of goodwill resulted from WEC's analysis that demonstrated the cost to complete the four Westinghouse AP1000 new nuclear plants in the United States would far surpass the original estimates for construction. In public statements in 2017, Toshiba attributed the cost overruns to, among other things, higher labor costs arising from lower than anticipated work efficiency and the inability to improve such work efficiency over time. While the final figures related to the impairment remain subject to adjustment, Toshiba's February 14, 2017 announcement indicated it anticipates it will record a loss in excess of $6 billion.

Toshiba's credit ratings, already below investment grade following disclosures of accounting and internal control irregularities in 2015, were further reduced in January 2017, and the Company and Consolidated SCE&G expect that Toshiba will continue to experience negative financial repercussions resulting from these developments. In response, Toshiba has announced, among other things, its plan to monetize portions of its businesses to generate cash. It has also indicated that it will not take on future nuclear construction projects and that it will significantly alter its risk management oversight of its nuclear business. The ability of WEC and Toshiba to successfully respond to these developments will continue to impact Toshiba's credit ratings, creditworthiness, financial stability and viability. There can be no assurance that Toshiba's or WEC's actions will be sufficient such that Toshiba's lenders and creditors will continue to provide necessary liquidity. In particular, these losses raise uncertainty with respect to Toshiba's ability to perform under its guaranty of WEC's payment obligations to the Company and Consolidated SCE&G, and further highlight the risks to the Company and Consolidated SCE&G related to the construction schedule and WEC's ability to continue with and/or complete the construction of the New Units. Adverse changes in contracts, contractors and subcontractors, and to the project schedule could result. Additionally, contractual disputes and litigation could follow.

In addition to the project risks highlighted in Toshiba's disclosures surrounding the large losses described above, additional risks and uncertainties regarding the project schedule are evident. In February 2017, WEC notified the Company and Consolidated SCE&G that the contractual guaranteed substantial completion dates of August 2019 and 2020 for Unit 2 and Unit 3, respectively, which were reflected in the October 2015 Amendment, are not likely to be met. Instead, revised substantial completion dates of April 2020 and December 2020 are reflected within WEC's revised project schedule. While these later dates remain within the SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits, there remains substantial uncertainty as to WEC's ability to meet these dates given its historical inability to meet forecasted productivity and work force efficiency levels.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under any of several arrangements with other contractors or, were it determined to be prudent, halting the project, leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA. Any significant delay in the timing of construction or any determination by the SCPSC to disallow the recovery of costs would adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

Commodity price changes, delays in delivery of commodities, commodity availability and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs), availability and deliverability. Any such changes could affect the prices these businesses charge, their operating costs, and the competitive position of their products and services. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to result in the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial condition.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternate forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers on a volumetric rate structure unable to switch to alternate fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G. A regulatory mechanism applies to residential and commercial customers at PSNC Energy to mitigate the earnings impact of an increase or decrease in gas usage.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e., natural gas) market risk. We could be required to provide cash collateral or recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract.

The Company strives to manage commodity price exposure by establishing risk limits and utilizing various financial instruments (exchange traded and over-the-counter instruments) to hedge physical obligations and reduce price volatility. We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be adversely impacted.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, the Department of Homeland Security, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental agencies, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our businesses. In addition to many other aspects of our businesses, these requirements impact the services mandated or offered to our customers, and the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. Non-compliance with these requirements by third parties, such as our contractors, vendors and agents, may subject the Company and Consolidated SCE&G to operational risks and to liability. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's or Consolidated SCE&G's businesses. Non-compliance with these laws and regulations could result in fines, litigation, loss of licenses or permits, mandated capital expenditures and other adverse business outcomes, as well as reputational damage, which could adversely affect the cash flows, results of operations, and financial condition of the Company and Consolidated SCE&G.

Furthermore, changes in or uncertainty in monetary, fiscal, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G could be adversely impacted by changes in tax policy, such as the loss of production tax credits related to the construction of the New Units.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects, results of DSM Programs, results of DER programs, and/or increases in operating costs may lead to requests for regulatory relief, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits.

SCE&G's electric operations in South Carolina and the Company's gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. Consolidated SCE&G's generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. SCE&G's electric transmission system is subject to extensive regulations and oversight from the SCPSC, NERC and FERC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as market conditions evolve.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement, many of which are still pending final action by those federal agencies. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers and major swap participants, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers or major swap participants, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated

SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Although we believe that we have constructive relationships with the regulators, our ability to obtain rate treatment that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing NO_X, SO_2, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh. No new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030. However, on February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. Also, a number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none has yet been enacted. In April 2012, the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. The EPA's rule for cooling water intake structures to meet the best technology available became effective in October 2014, and the EPA also issued a final rule in December 2014 regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA finalized new standards under the CWA governing effluent limitation guidelines for electric generating units in September 2015.

Compliance with these environmental laws and regulations requires us to commit significant resources toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as the clean-up of MGP sites or additional emission allowances) or require us to incur additional expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our businesses and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. In June 2014 the State of South Carolina enacted legislation known as Act 236 with the stated goal for each investor-owned utility to supply up to 2% of its 5-year average retail peak demand with renewable electric generation resources by the end of 2020. A utility, at its option, may supply an additional 1% during this period. Such renewable energy may not be readily available in our service territories and could be costly to build, finance, acquire, integrate, and/or operate. Resulting increases in the price of electricity to recover the cost of these types of generation, as approved by regulatory commissions, could result in lower usage of electricity by our customers. In addition, DER generation at customers' facilities could result in the loss of sales to those customers. Compliance with potential future portfolio standards could significantly impact our capital expenditures and our results of operations and financial condition. Utility scale solar development companies are currently working in South Carolina to develop projects in SCE&G's service territory. The integration of those resources at high penetration levels may be challenging.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In effecting compliance with MATS, SCE&G has retired three of its oldest and smallest coal-fired units and converted three others such that they may be gas-fired.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and we may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company's and Consolidated SCE&G's business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company's and Consolidated SCE&G's ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and its actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA's pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition, including its shareholders' equity.

A downgrade in the credit rating of SCANA or any of SCANA's subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies currently rate SCANA's long-term senior unsecured debt, SCE&G's long-term senior secured debt, and the long-term senior unsecured debt of PSNC Energy as investment grade. In addition, rating agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of our rated companies' commonly monitored financial credit metrics and adverse developments with respect to nuclear construction could negatively affect their debt ratings. If these rating agencies were to downgrade any of these ratings, particularly to below investment grade for long-term ratings, borrowing costs on new issuances would increase, which could adversely impact financial results, and the potential pool of investors and funding sources could decrease.

The Company and Consolidated SCE&G are engaged in activities for which they have claimed, and expect to claim in the future, research and experimentation tax deductions and credits which are the subject of uncertainty and which may be considered controversial by the taxing authorities. The outcome of those uncertainties could adversely impact cash flows and financial condition.

The Company and Consolidated SCE&G have claimed significant research and experimentation tax deductions and credits related to the ongoing design and construction activities of the New Units. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. (See also Uncertain income tax positions within the Critical Accounting Policies and Estimates section of Item 7.

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These tax claims primarily involve the timing of recognition of tax deductions rather than permanent tax attributes. The permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to them, have been deferred within regulatory assets. As such, these claims have not had, and are not expected to have in the future, significant direct effects on the Company’s and Consolidated SCE&G’s results of operations. Nonetheless, the claims have contributed significantly to the Company’s and Consolidated SCE&G’s cash flows and are expected to continue to do so through the remainder of the New Units’ construction period. Also, the claims have provided a significant source of capital and have lessened the level of debt and equity financing that the Company and Consolidated SCE&G have needed to raise in the financial markets. Future claims are expected to provide similar tax benefits.

However, the claims made to date are under examination, and may be considered controversial, by the IRS. It is expected that the IRS will also examine future claims. To the extent that the claims are not sustained on examination or through any subsequent appeal, the Company and Consolidated SCE&G will be required to repay any cash received for tax benefit claims which are ultimately disallowed, along with interest on those amounts. Such amounts could be significant and could adversely affect the Company's and Consolidated SCE&G's cash flows and financial condition. In certain circumstances, which management considers to be remote, penalties for underpayment of income taxes could also be assessed. Additionally, in such circumstances, the Company and Consolidated SCE&G may need to access the capital markets to fund those tax and interest payments, which could in turn adversely impact their ability to access financial markets for other purposes.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and, in deregulated markets, received lower prices for natural gas when weather conditions have been milder than normal, and as a consequence earned less income from those operations. Mild weather in the future could adversely impact the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as hurricanes or other significant weather events, electromagnetic events or the 2011 earthquake and tsunami in Japan) or man-made mishaps (such as the San Bruno, California natural gas transmission pipeline failure, electric utility companies' ash pond failures, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial condition, operating expenses, and cash flows.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via an RTO/ISO is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should an RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new delivery transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina or North Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company’s and Consolidated SCE&G’s generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets could be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems, which systems have undergone a rapid decline in their costs. As a result of federal and state subsidies, potential regulations allowing third-party retail sales, and advances in distributed generation technology, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and will slow growth, potentially causing higher rates to customers.

The Company and SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in higher costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally, legislative actions (including tax reform), or regulatory actions. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns. For instance, improvements in energy storage technology, if realized, could have dramatic impacts on the viability of and growth in distributed generation.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms that are attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be adversely impacted.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission equipment failure, information systems failure or security breach, operator error, natural disasters, and the effects of a pandemic, terrorist attack or cyber attack on our workforce or facilities or on vendors and suppliers necessary to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The operation of the New Units or the integration of a significant amount of distributed generation into our systems may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a natural gas line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's and Consolidated SCE&G's revenues, results of operations, cash flows, and financial condition. Insurance may not be available or adequate to mitigate the adverse impacts of these events.

A failure of the Company and Consolidated SCE&G to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows.

The Company and Consolidated SCE&G depend on maintaining the physical and cyber security of their operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our businesses could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's and Consolidated SCE&G's operations are dependent in some manner upon our cyber systems, which encompass electric and gas operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company and Consolidated SCE&G, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, vendor, shareholder, employee, or corporate information. The Company and Consolidated SCE&G may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to mitigate the adverse impacts of these events. As a result, the Company's and Consolidated SCE&G's financial condition, results of operations, and cash flows may be adversely affected.

SCANA's ability to pay dividends and to make payments on SCANA's debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital.

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SCANA Energy, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of Consolidated SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition. These risks will increase as the New Units are developed.

In 2016, Unit 1 provided approximately 5.8 million MWh, or 25% of our generation. When the New Units are completed, our generating capacity and the percentage of total generating capacity represented by nuclear sources are expected to increase. Hence, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and suppliers thereof, fabrication of nuclear fuel and related vendors, and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In today's environment, there is a heightened risk of terrorist attack on the nation's nuclear facilities, which has resulted in increased security costs at our nuclear plant. Although we have no reason to anticipate a serious nuclear incident, a major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit, resulting in costly changes to units under construction or in operation and adversely impacting our results of operations, cash flows and financial condition. Furthermore, a major incident at a domestic nuclear facility could result in retrospective premium assessments under our nuclear insurance coverages.

Failure to retain and attract key personnel could adversely affect the Company's and Consolidated SCE&G's operations and financial performance.

As with many other utilities, a significant portion of our workforce will be eligible for retirement during the next few years. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our businesses. Competition for these employees is high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. In particular, the timely hiring, training, licensing and retention of personnel needed for the operation of the New Units is necessary to maintain the schedule for their operation. Further, the Company's or Consolidated SCE&G's ability to construct or maintain generation or other assets including the New Units requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance. Furthermore, increased medical benefit costs of employees and retirees could adversely affect the results of operations of the Company and Consolidated SCE&G. Medical costs in this country have risen significantly over the past number of years and are expected to continue to increase at unpredictable rates. Such increases, unless satisfactorily managed by the Company and Consolidated SCE&G, could adversely affect results of operations.

The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial condition, and access to capital.

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes, including customers' concerns regarding rate increases, such as those periodic rate increases under the BLRA, may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously supported by legislation or approved by regulators), to the detriment of the Company or Consolidated SCE&G (e.g., revision or repeal of the BLRA). Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company's or Consolidated SCE&G's interests, may have a negative effect on our results of operations, cash flows and financial condition, as well as limit our ability to access capital.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards related to compliance with laws and regulations, ethical conduct, operational effectiveness, customer service and the safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company's and Consolidated SCE&G's access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to assure reliability of provided services, to focus on the safety of employees, customers and the public, to ensure environmental compliance, to maintain the privacy of information related to our customers and employees, and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. Traditional news media and social media can very rapidly convey information, whether factual or not, to large numbers of people, including customers, investors, regulators, legislators and other stakeholders, and the failure to effectively manage timely, accurate communication through these channels could adversely impact our reputation. The Company and Consolidated SCE&G also are committed to operational excellence, to quality customer service, and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments may subject the Company and Consolidated SCE&G not only to fraud, regulatory action, litigation and financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries.

SCE&G's bond indenture, which secures its First Mortgage Bonds, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

Electric Properties

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2016.

	In-Service Date	Net Generating Capacity Summer (MW)
Coal-Fired Steam:		
Wateree - Eastover, SC	1970	684
Williams - Goose Creek, SC	1973	605
Cope - Cope, SC	1996	415
Kapstone - Charleston, SC	1999	85
Gas-Fired Steam:		
McMeekin - Irmo, SC	1958	250
Urquhart Unit 3 - Beech Island, SC	1953	95
Nuclear:		
Summer Station Unit 1 - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647
Summer Station Unit 2 and Unit 3 - Parr, SC		*
Internal Combustion Turbines:		
Jasper Combined Cycle - Jasper, SC	2004	852
Urquhart Combined Cycle - Beech Island, SC	2002	458
Peaking units - various locations in SC	1968-2010	348
Hydro:		
Fairfield Pumped Storage - Parr, SC	1978	576
Saluda - Irmo, SC	1930	200
Other - various locations in or bordering SC	1905-1914	18

* SCE&G presently owns 55% of Unit 2 and Unit 3, which are being constructed at Summer Station.

SCE&G owns 433 substations having an aggregate transformer capacity of 31.5 million KVA. The transmission system consists of 3,442 miles of lines, and the distribution system consists of 18,522 pole miles of overhead lines and 7,441 trench miles of underground lines.

Natural Gas Distribution and Transmission Properties

SCE&G's natural gas system includes 447 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and DCGT. SCE&G’s distribution system consists of 17,375 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6,180 MMBTU per day and store the liquefied equivalent of 1,009,400 MMBTU of natural gas. The Salley facility can store the liquefied equivalent of 927,000 MMBTU of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 61,800 MMBTU per day at Charleston and 92,700 MMBTU per day at Salley.

PSNC Energy’s natural gas system consists of 606 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy’s distribution system consists of 21,686 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000,000 MMBTU, the capacity to liquefy up to 4,000 MMBTU per day and the capacity to regasify approximately 100,000 MMBTU per day.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G are subject to various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on their respective results of operations, cash flows or financial condition. In addition, certain material regulatory and environmental matters and uncertainties, some of which remain outstanding at December 31, 2016, are described in the Rate Matters section of Note 2 and in the Environmental section of Note 10 to the consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all wholly-owned subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	61	Chairman of the Board and Chief Executive Officer	*-present
		President and Chief Operating Officer-SCANA	*-present
Jimmy E. Addison	56	Executive Vice President-SCANA	*-present
		Chief Financial Officer	*-present
		President and Chief Operating Officer-SCANA Energy	2014-present
Jeffrey B. Archie	59	Senior Vice President and Chief Nuclear Officer-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Sarena D. Burch	59	Senior Vice President-Risk Management and Corporate Compliance Senior Vice President-Fuel Procurement and Asset Management-SCANA, SCE&G and PSNC Energy	2016-present *-2015
Stephen A. Byrne	57	President-Generation and Transmission and Chief Operating Officer-SCE&G	*-present
		Executive Vice President-SCANA	*-present
D. Russell Harris	52	President-Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		Senior Vice President-Gas Distribution-SCANA	2013-present
		Senior Vice President-SCANA	2012-2013
Kenneth R. Jackson	60	Senior Vice President-Economic Development, Governmental and Regulatory Affairs	2014-present
		Vice President-Rates and Regulatory Services	*-2014
W. Keller Kissam	50	President-Retail Operations-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Ronald T. Lindsay	66	Senior Vice President, General Counsel and Assistant Secretary	*-present
Randal M. Senn	60	Senior Vice President-Administration-SCANA	2016-present
		Vice President and Chief Information Officer	2016
		Chief Information Officer	*-2016

*Indicates positions held at least since February 24, 2012.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

SCANA:

Price Range (NYSE Composite Listing):

	2016				2015			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 74.94	$ 76.41	$ 75.67	$ 70.35	$ 61.95	$ 57.73	$ 56.26	$ 65.57
Low	$ 67.31	$ 69.04	$ 66.02	$ 59.46	$ 54.84	$ 50.17	$ 47.77	$ 52.03

SCANA common stock trades on the NYSE using the ticker symbol SCG. At February 20, 2017 there were 142,916,917 shares of SCANA common stock outstanding which were held by approximately 25,000 shareholders of record. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2016, see Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

SCANA declared quarterly dividends on its common stock of $0.575 per share in 2016 and $0.545 per share in 2015. On February 16, 2017, SCANA increased the quarterly cash dividend rate on SCANA common stock to $0.6125 per share, an increase of approximately 6.5%. The next quarterly dividend is payable April 1, 2017 to shareholders of record on March 10, 2017. For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

The following table provides information about purchases by or on behalf of SCANA or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended (Exchange Act)) of shares or other units of any class of SCANA's equity securities that are registered pursuant to Section 12 of the Exchange Act:

Issuer Purchases of Equity Securities

	(a)	(b)	(c)	(d)
Period	Total number of shares (or units) purchased	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1-31, 2016	7,583	$ 69.29	7,583	
November 1-30, 2016	—	—	—	
December 1-31, 2016	—	—	—	
Total	7,583		7,583	*

*The above table represents shares acquired for non-employee directors under the Director Compensation and Deferral Plan. On December 16, 2014, SCANA announced a program to convert from original issue to open market purchase of SCANA common stock for all applicable compensation and dividend reinvestment plans. This program took effect in the first quarter of 2015 and has no stated maximum number of shares that may be purchased and no stated expiration date.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2016 and 2015, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount
February 18, 2016	$ 72.2 million	February 20, 2015	$ 69.0 million
April 28, 2016	73.3 million	April 30, 2015	67.8 million
July 28, 2016	74.0 million	July 30, 2015	68.4 million
October 27, 2016	77.5 million	October 29, 2015	72.3 million

On February 16, 2017, SCE&G declared a quarterly dividend on its common stock of $76.9 million.

For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2016	2015	2014	2013	2012
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$ 4,227	$ 4,380	$ 4,951	$ 4,495	$ 4,176
Operating Income	$ 1,153	$ 1,308	$ 1,007	$ 910	$ 859
Net Income	$ 595	$ 746	$ 538	$ 471	$ 420
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.9	142.9	141.9	138.7	131.1
Basic Earnings Per Share	$ 4.16	$ 5.22	$ 3.79	$ 3.40	$ 3.20
Diluted Earnings Per Share	$ 4.16	$ 5.22	$ 3.79	$ 3.39	$ 3.15
Dividends Declared Per Share of Common Stock	$ 2.30	$ 2.18	$ 2.10	$ 2.03	$ 1.98
Balance Sheet Data					
Utility Plant, Net	$ 14,324	$ 13,145	$ 12,232	$ 11,643	$ 10,896
Total Assets	$ 18,707	$ 17,146	$ 16,818	$ 15,127	$ 14,568
Total Equity	$ 5,725	$ 5,443	$ 4,987	$ 4,664	$ 4,154
Short-term and Long-term Debt	$ 7,431	$ 6,529	$ 6,581	$ 5,788	$ 5,707
Other Statistics					
Electric:					
Customers (Year-End)	709,418	698,372	687,800	678,273	669,966
Total sales (Million kWh)	23,458	23,102	23,319	22,313	23,879
Generating capability-Net MW (Year-End)	5,233	5,234	5,237	5,237	5,533
Territorial peak demand-Net MW	4,807	4,970	4,853	4,574	4,761
Regulated Gas:					
Customers, excluding transportation (Year-End)	906,883	881,295	859,186	837,232	818,983
Sales, excluding transportation (Thousand Therms)	890,113	875,218	973,907	921,533	798,978
Transportation customers (Year-End)	632	627	656	667	663
Transportation volumes (Thousand Therms)	674,999	791,402	1,786,897	1,729,399	1,559,542

For information on the impact of certain dispositions on SCANA's selected financial data, see Note 1 to the consolidated financial statements.

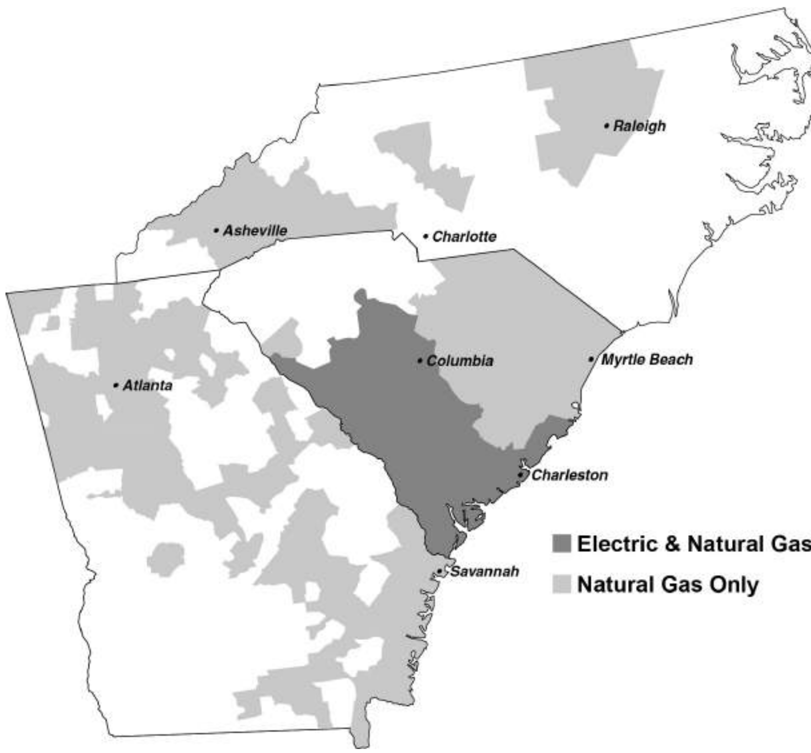
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pursuant to General Instruction I of Form 10-K, SCE&G is permitted to omit certain information related to itself and its consolidated affiliates called for by Item 7 of Form 10-K, and instead provide a management's narrative explanation of its consolidated results of operation and other information described therein. Such information is presented hereunder specifically for Consolidated SCE&G, but may be presented alongside information presented for the Company generally. Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation and its subsidiaries (other than Consolidated SCE&G).

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

The following map indicates areas where the Company's significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect amounts attributable to the Company's regulated and nonregulated operations and other nonregulated (including the holding company and the services company).

	2016	2015	2014
Net Income			
Regulated	98 %	72%	98 %
Nonregulated operations	5 %	4%	7 %
Other nonregulated	(3)%	24%	(5)%
Assets			
Regulated	97 %	97%	95 %
Nonregulated operations	1 %	1%	2 %
Other nonregulated	2 %	2%	3 %

In the first quarter of 2015, SCANA closed on the sales of its interstate natural gas pipeline and telecommunications subsidiaries. Gains from these sales are included within Other. See Dispositions in Note 1 to the consolidated financial statements.

Key Earnings Drivers and Outlook

In 2016, companies announced plans to invest over $1.8 billion, with the expectation of creating approximately 7,000 jobs in the Company's South Carolina and North Carolina service territories. At December 31, 2016, South Carolina's unemployment rate was 4.3%, which is approximately 1.2% lower than the prior year. In addition, each of the Company's regulated businesses experienced positive customer growth year over year.

Over the next five years, key earnings drivers for the Company are expected to be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business and the level of growth of operation and maintenance, interest and other expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generate electricity and provide for its transmission, distribution and sale to approximately 709,000 customers (as of December 31, 2016) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity compared to other energy sources.

Embedded in the rates charged to customers is an allowed regulatory ROE. SCE&G's allowed ROE in 2016 was 10.25% for non-BLRA rate base and 10.5% for BLRA-related rate base. For BLRA-related rate base existing prior to 2016, SCE&G's allowed ROE was 11.0%.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and SCE&G has agreed to acquire an additional 5% ownership from Santee Cooper in increments beginning with the commercial operation date of Unit 2.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding certain disputes, and the EPC Contract was amended. The October 2015 Amendment became effective on December 31, 2015, and among other things, it resolved by settlement and release substantially all then-outstanding disputes between SCE&G and the Consortium. The October 2015 Amendment also provided SCE&G and Santee Cooper an option, subject to regulatory approvals, to fix the total amount to be paid to the Consortium for its entire scope of work on the project after June 30, 2015, subject to certain exceptions. In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units developed as a result of the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively, although recent communications from WEC indicate substantial completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits. However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to meet forecasted productivity and work force efficiency levels.

The approved capital cost schedule includes incremental capital costs. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under any of several arrangements with other contractors or, were it determined to be prudent, halting the project, leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA. Any significant delay in the timing of construction or any determination by the SCPSC to disallow the recovery of costs would adversely impact results of operations, cash flows and financial condition.

The information summarized above, as well as additional information regarding uncertainties concerning WEC's ability to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project and other related matters, is further discussed in Note 2 and Note 10 to the consolidated financial statements.

Environmental

The results of recent elections may affect the pace at which federal environmental laws and regulations are enacted or how stringently their provisions are interpreted in the future. However, public sentiment surrounding air quality and water quality remains strong and is expected to continue unabated.

Over several years, SCE&G has made significant investments in constructing non-emitting generation (the New Units previously mentioned) and retiring certain coal-fired plants or converting them to burn natural gas. In addition, SCE&G expects to add the renewable energy from six new solar generating facilities at locations throughout its electric service territory over the next few years. The impact of these investments is expected to result in a significant shift toward non-emitting sources of fuel used to generate electricity in the future.

Generation Type	2016 Actual	2021 Projected
Nuclear	24.7%	56.7%
Hydro	3.3%	3.4%
Solar	—%	2.2%
Total Non-emitting	**28.0%**	**62.3%**
Biomass	1.7%	—%
Natural Gas	33.5%	17.9%
Coal	36.8%	19.8%
Total Generation	100.0%	100.0%

In addition, SCE&G and GENCO have made significant investments to install pollution control equipment at their remaining coal-fired plants. These investments, together with investments in non-emitting generation, have reduced their air emissions and are expected to result in additional reductions in the future.

Emissions, measured in thousands of tons			
Year	**NO_X**	**SO_2**	**CO_2**
2005	27.0	107.9	18,778.7
2013	7.0	19.3	12,507.9
2014	7.6	16.8	13,984.6
2015	5.7	5.1	12,891.8
2016	5.4	2.7	11,567.4
2021*	3.2	1.2	7,062.5
% decrease from 2005 to 2021*	**88.1%**	**98.9%**	**62.4%**

* Projected

The status of significant environmental laws and regulations and certain initiatives undertaken to ensure compliance with them are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. In addition, uncertainties with respect to the New Units are described in Note 10 to the consolidated financial statements.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 907,000 retail customers (as of December 31, 2016) in portions of South Carolina and North Carolina in areas covering approximately 35,000 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory ROE for SCE&G of 10.25% and for PSNC Energy of 10.60% through October 31, 2016 and 9.7% thereafter.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company’s ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at generally low levels for several years. The supply of natural gas from the Marcellus shale basin has prompted companies unaffiliated with SCANA to propose a 550-mile pipeline that would bring natural gas from West Virginia to Virginia and North Carolina. This pipeline is expected to be completed in late 2019 and, if successful, it may drive economic development along its path, including areas within PSNC Energy's service territory, and may serve to assist in keeping natural gas competitively priced in the region.

Gas Marketing

SCANA Energy markets natural gas in the southeast and provides energy-related services to customers, including, notably, retail customers in Georgia. Operating results for energy marketing are influenced by customer demand for natural gas and the ability to control costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, the availability of certain pipeline capacity to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the Georgia retail market. SCANA Energy sells natural gas to approximately 450,000 customers (as of December 31, 2016) throughout Georgia. This market is mature, resulting in lower margins and stiff competition. Competitors include affiliates of large energy companies as well as electric membership cooperatives, among others. SCANA Energy’s ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy's operating results are sensitive to weather.

RESULTS OF OPERATIONS

Earnings and Dividends

Earnings and dividends were as follows:

	2016	2015	2014
The Company			
Earnings per share	$ 4.16	$ 5.22	$ 3.79
Cash dividends declared per share	$ 2.30	$ 2.18	$ 2.10
Consolidated SCE&G			
Net income (millions of dollars)	$ 525.8	$ 479.5	$ 457.7

On February 16, 2017, SCANA declared a quarterly cash dividend on its common stock of $0.6125 per share.

2016 vs 2015

Earnings per share decreased primarily due to the sales of CGT and SCI in 2015, higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense. These decreases were partially offset by higher electric and gas distribution margins, higher other income net of other expenses and higher energy marketing net income, as further described below.

Consolidated SCE&G's net income increased primarily due to higher electric and gas distribution margins, partially offset by higher operation and maintenance expense, higher depreciation expense, higher property taxes, higher interest cost, and higher income taxes, as further described below.

2015 vs 2014

Earnings per share increased due to the sales of CGT and SCI in 2015, higher electric margins, lower operation and maintenance expenses and lower depreciation expense. These increases were partially offset by lower gas margins, higher property taxes, lower other income, higher interest expense, a higher effective tax rate and dilution from additional shares outstanding, as further described below.

The sales of CGT and SCI were closed in the first quarter of 2015. These subsidiaries operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. Therefore, CGT and SCI were not a part of the Company's core business. See Note 12 to the consolidated financial statements.

Consolidated SCE&G's net income increased primarily due to higher electric and gas distribution margins and lower depreciation expense, partially offset by lower other income, higher operation and maintenance expense, higher property taxes, higher interest cost, and higher income taxes, as further described below.

Electric Operations

Electric Operations for the Company and for Consolidated SCE&G is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric Operations operating income (including transactions with affiliates) was as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Operating revenues	$ 2,619.4	$ 2,557.1	$ 2,629.4	$ 2,619.4	$ 2,557.1	$ 2,629.4
Fuel used in electric generation	576.1	660.6	799.3	576.1	660.6	799.3
Purchased power	63.7	52.1	80.7	63.7	52.1	80.7
Margin	1,979.6	1,844.4	1,749.4	1,979.6	1,844.4	1,749.4
Other operation and maintenance	526.1	497.1	494.8	540.2	509.6	507.5
Depreciation and amortization	286.5	277.3	300.3	274.9	266.9	289.5
Other taxes	210.4	194.5	186.7	207.9	192.4	184.8
Operating Income	$ 956.6	$ 875.5	$ 767.6	$ 956.6	$ 875.5	$ 767.6

Electric operations can be significantly impacted by the effects of weather. SCE&G estimates the effects on its electric business of actual temperatures in its service territory as compared to historical averages to develop an estimate of electric margin revenue attributable to the effects of abnormal weather. Results in 2016 reflect warmer than normal weather in the second and third quarters and milder than normal weather in the first and fourth quarters. Results in 2015 reflect colder than normal weather in the first quarter, warmer than normal weather in the second and third quarters and milder than normal weather in the fourth quarter. Results in 2014 reflect colder than normal weather in the first quarter, hotter than normal weather in the second and third quarters and milder than normal weather in the fourth quarter.

2016 vs 2015

- Margin increased due to base rate increases under the BLRA of $60.7 million, the effects of weather of $22.1 million, residential and commercial customer growth of $22.1 million, higher industrial margin of $7.6 million and higher collections under the rate rider for pension costs of $13.5 million. These margin increases were partially offset by lower residential and commercial average use. The higher pension rider collections had no effect on net income as they were fully offset by the recognition, within other operation and maintenance expenses, of higher pension costs. Margin also increased due to downward revenue adjustments in 2015, pursuant to orders from the SCPSC, to apply $14.5 million as an offset to fuel cost recovery upon the adoption of new (lower) electric depreciation rates and by $5.2 million related to DSM Programs. These adjustments had no effect on net income in 2015 as they were fully offset by the recognition of $14.5 million of lower depreciation expense and by the recognition, within other income, of $5.2 million of gains realized upon the settlement of certain interest rate contracts.
- Other operation and maintenance expenses increased due to higher labor costs of $25.4 million, primarily due to increased pension cost associated with the higher pension rider collections and higher incentive compensation costs. Other operation and maintenance expenses also increased due to higher amortization of DSM program costs of $2.0 million.
- Depreciation and amortization increased primarily due to net plant additions.
- Other taxes increased primarily due to higher property taxes on net plant additions.

2015 vs 2014

- Margin increased due to downward adjustments of $69.0 million in 2014, compared to downward adjustments of $19.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and DSM Programs. These adjustments had no effect on net income as they were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts, lower depreciation expense upon the adoption and implementation of revised depreciation rates as a result of an updated depreciation study and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve. Margin also increased due to base rate increases under the BLRA of $65.7 million and residential and commercial customer growth of $21.4 million. These increases were partially offset by $25.6 million due to the effects of weather, lower industrial margins of $14.6 million primarily due to variable price contracts, and lower collections under the rate rider for pension costs of $3.0 million. See Note 2 to the consolidated financial statements.

- Other operation and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider collections.
- Depreciation and amortization decreased by $28.7 million in 2015 due to the implementation of the above mentioned revised depreciation rates, $14.5 million of which was offset by downward revenue adjustments. This decrease in depreciation expense was partially offset by increases associated with net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric operations margin above, by class, were as follows:

Classification	2016	2015	2014
Residential	8,140	7,978	8,156
Commercial	7,506	7,386	7,371
Industrial	6,265	6,201	6,234
Other	600	595	600
Total retail sales	22,511	22,160	22,361
Wholesale	947	942	958
Total Sales	23,458	23,102	23,319

2016 vs 2015

Retail sales volumes increased primarily due to the effects of weather and customer growth.

2015 vs 2014

Retail sales volumes decreased primarily due to the effects of weather, partially offset by customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G, and for the Company, also includes PSNC Energy. Gas Distribution operating income (including transactions with affiliates) was as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	2016	2015	2014	2016	2015	2014
Operating revenues	$ 789.8	$ 811.7	$ 1,014.0	$ 366.8	$ 372.7	$ 462.2
Gas purchased for resale	345.9	383.7	592.5	182.9	192.5	283.1
Margin	443.9	428.0	421.5	183.9	180.2	179.1
Other operation and maintenance	172.7	161.4	154.8	73.6	69.8	67.7
Depreciation and amortization	82.0	77.5	72.4	27.3	26.8	25.7
Other taxes	41.5	37.5	34.8	26.8	24.9	23.1
Operating Income	$ 147.7	$ 151.6	$ 159.5	$ 56.2	$ 58.7	$ 62.6

The effect of abnormal weather conditions on gas distribution margin is mitigated by the WNA at SCE&G and the CUT at PSNC Energy as further described in Revenue Recognition in Note 1 of the consolidated financial statements. The WNA and CUT affect margins but not sales volumes.

2016 vs 2015

- Margin increased $11.5 million at the Company, including $6.0 million at SCE&G, due to residential and commercial customer growth, $5.0 million due to an NCUC-approved rate increase effective November 2016 at PSNC Energy, and $1.1 million due to an SCPSC-approved increase in base rates under the RSA effective November 2016 at SCE&G. These increases were partially offset by lower average use of $4.1 million at SCE&G.
- Other operation and maintenance expenses increased due to higher labor costs of $6.7 million at the Company, including $2.1 million at SCE&G, due primarily to higher incentive compensation costs.
- Depreciation and amortization increased at the Company and SCE&G due to net plant additions, partially offset by the implementation of SCPSC-approved revised (lower) depreciation rates at SCE&G of $1.1 million.
- Other taxes increased at the Company and SCE&G due to net plant additions.

2015 vs 2014

- Margin increased due to residential and commercial customer growth of $7.8 million at the Company, including $4.3 million at SCE&G, partially offset by a decrease of $3.1 million due to an SCPSC-approved decrease in base rates at SCE&G under the RSA effective November 2014.
- Other operation and maintenance expenses increased at the Company and SCE&G due to higher labor costs, primarily due to incentive compensation.
- Depreciation and amortization increased at the Company and SCE&G due to net plant additions.
- Other taxes increased at the Company and SCE&G due primarily to higher property taxes associated with net plant additions.

Sales volumes (in MMBTU) related to gas distribution margin by class, including transportation, were as follows:

	The Company			Consolidated SCE&G		
Classification (in thousands)	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Residential	40,142	39,090	46,207	12,420	12,086	14,917
Commercial	29,078	28,064	30,701	12,879	12,580	13,936
Industrial	19,364	20,101	20,343	17,228	17,901	18,307
Transportation gas	49,769	49,297	45,506	5,250	4,781	4,286
Total	138,353	136,552	142,757	47,777	47,348	51,446

2016 vs 2015

Residential and commercial firm sales volumes increased primarily due to customer growth. Commercial and industrial interruptible volumes decreased, and firm volumes increased, due to customers switching from interruptible to firm service at SCE&G. Industrial volumes decreased and transportation volumes increased due to customers switching to transportation only service.

2015 vs 2014

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use, partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to a shift to transportation service from system supply and the impact of curtailments, partially offset at the Company by lower curtailments at PSNC Energy. Transportation volumes increased due to customers shifting to transportation-only service at SCE&G, and at the Company, included increased sales for natural gas fired electric generation in PSNC Energy's territory.

Gas Marketing

Gas Marketing is comprised of the Company's nonregulated marketing operation, SCANA Energy, which operates in the southeast and includes Georgia's retail natural gas market. Gas Marketing operating revenues and net income were as follows:

Millions of dollars	**2016**	**2015**	**2014**
Operating revenues	$ 936.7	$ 1,146.7	$ 1,496.4
Net Income	29.8	27.6	31.0

2016 vs 2015

Operating revenues decreased due to the lower market price of natural gas and lower industrial sales volume. Net income increased primarily due to a weather-related increase in demand.

2015 vs 2014

Operating revenues decreased due to the lower market price of natural gas, weather-related changes in demand, lower industrial sales volume and lower market prices. Net income decreased primarily due to weather-related changes in demand, partially offset by lower cost of gas and lower costs of transportation to serve customers.

Other Operating Expenses

Other operating expenses were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Other operation and maintenance	$ 755.6	$ 715.3	$ 728.3	$ 613.8	$ 579.4	$ 575.2
Depreciation and amortization	370.9	357.5	383.7	302.2	293.7	315.2
Other taxes	253.9	234.2	228.8	234.7	217.3	207.9

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in those discussions. Additional information is provided below.

2016 vs 2015

In addition to factors discussed in the electric operations and gas distribution segments, overall increases in other operating expenses were partially offset by the Company's sale of CGT in early 2015, which resulted in decreases in other operation and maintenance expenses of $2.2 million, depreciation and amortization of $0.7 million and other taxes of $0.5 million.

2015 vs 2014

In addition to factors discussed in the electric operations and gas distribution segments, the Company's sale of CGT in early 2015 resulted in decreases in other operation and maintenance expenses of $24.2 million, depreciation and amortization of $7.8 million and other taxes of $8 million.

Net Periodic Benefit Cost

Other operation and maintenance expense includes net periodic benefit cost, which was recorded on the income statements and balance sheets as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Income Statement Impact:						
Employee benefit costs	$ 19.2	$ 5.3	$ 5.0	$ 16.4	$ 2.8	$ 4.0
Other expense	0.9	1.1	0.2	0.2	0.2	0.1
Balance Sheet Impact:						
Increase in capital expenditures	5.3	3.9	0.5	4.7	3.4	0.3
Component of amount receivable from Summer Station co-owner	2.1	1.5	0.1	2.1	1.5	0.1
Increase (decrease) in regulatory assets	(4.6)	6.2	(3.2)	(4.6)	6.2	(3.2)
Net periodic benefit cost	$ 22.9	$ 18.0	$ 2.6	$ 18.8	$ 14.1	$ 1.3

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were $2.0 million for retail electric operations and $1.0 million for gas operations for each period presented.

Other Income (Expense)

Other income (expense) includes the results of certain incidental non-utility activities of regulated subsidiaries, the activities of certain of the Company's non-regulated subsidiaries, and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. An equity portion of AFC is included in nonoperating income and a debt portion of AFC is included in interest charges (credits), both of which have the effect of increasing reported net income. Components of other income (expense) and AFC were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Other income	$ 64.4	$ 74.5	$ 121.8	$ 29.3	$ 31.1	$ 79.8
Other expense	(38.5)	(60.1)	(64.3)	(24.1)	(31.1)	(33.8)
Gain on sale of SCI, net of transaction costs	—	106.6	—	—	—	—
AFC - equity funds	29.4	27.0	32.7	26.1	24.8	27.7

2016 vs 2015

Other income at the Company and Consolidated SCE&G decreased by $3.5 million due to lower gains on the sale of land and due to the recognition in 2015 of $5.2 million of gains realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). At the Company, other income also decreased by $3.9 million and other expenses decreased by $2.3 million due to the sale of SCI, and other income and other expenses decreased by $10.5 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. Other expenses at the Company and Consolidated SCE&G decreased by $5.2 million due to lower contribution expenses. In 2015, the Company's other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC increased due to construction activity.

2015 vs 2014

Other income decreased at the Company and Consolidated SCE&G due primarily to the recognition of $64.0 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). At the Company, other income also decreased by $18.3 million and other expenses decreased by $10.9 million due to the sale of SCI, and other income and other expenses increased by $12.7 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. In 2015, the Company's other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC decreased due to lower AFC rates.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Interest on long-term debt, net	$ 330.3	$ 311.3	$ 306.7	$ 253.8	$ 236.0	$ 217.6
Other interest expense	12.0	6.5	5.7	16.2	12.1	10.4
Total	$ 342.3	$ 317.8	$ 312.4	$ 270.0	$ 248.1	$ 228.0

Interest expense increased in each year primarily due to increased borrowings.

Income Taxes

At the Company, income tax expense decreased from 2015 to 2016 primarily due to lower income before taxes. Income tax expense increased from 2014 to 2015 primarily due to higher income before taxes. Income before taxes, income taxes and the effective tax rate were all higher in 2015 primarily due to the sales of CGT and SCI. At Consolidated SCE&G, income tax expense increased each year primarily due to increases in income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to meet contractual cash obligations in 2017 through internally generated funds and additional short- and long-term borrowings. The Company may also meet such obligations through the sale of equity securities. The Company expects that, barring a future impairment of the capital markets or its access to such markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

Due primarily to the availability of proceeds from the sale of two subsidiaries in the first quarter of 2015, the Company began using open market purchases for its stock plans at the end of January 2015. Prior to the use of open market purchases, SCANA common stock was acquired on behalf of participants in SCANA's Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares. This provided additional equity of approximately $14 million in 2015.

Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of the Company's or its rated operating companies' commonly monitored financial credit metrics and adverse developments with respect to nuclear construction could negatively affect the Company's debt ratings. This could cause the Company to pay higher interest rates on its long- and short-term indebtedness, and could limit the Company's access to capital markets and liquidity.

Cash provided from operating activities in 2015 reflects lower tax payments arising from Congress' extension of bonus deprecation provisions in 2014. Cash provided from operating activities in 2016 reflects significant tax benefits (reductions in income tax payments) arising from the deduction under Section 174 of the IRC of certain expenditures related to the design and construction of the New Units and the related claim of credits under Section 41 of the IRC. Similar tax benefits are expected to be claimed in the next several years as design and construction continues, and these cash flows are expected to continue to supplant portions of financing which would otherwise be obtained in the capital markets.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.6 billion in 2016. Estimates of capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2017	2018	2019
SCE&G - Normal			
Generation	$ 138	$ 124	$ 148
Transmission & Distribution	180	205	207
Other	10	16	26
Gas	74	85	76
Common	4	3	9
Total SCE&G - Normal	406	433	466
PSNC Energy	332	242	182
Other	31	21	28
Total Normal	769	696	676
New Nuclear (including transmission) - SCE&G*	1,222	1,165	501
Cash Requirements for Construction*	1,991	1,861	1,177
Nuclear Fuel - SCE&G	80	89	111
Total Estimated Capital Expenditures*	$ 2,071	$ 1,950	$ 1,288

*Excludes the impact of the updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. See Note 10 to the consolidated financial statements.

Contractual cash obligations as of December 31, 2016 are summarized as follows:

Contractual Cash Obligations	**Payments due by periods**				
Millions of dollars	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long- and short-term debt, including interest	$ 13,976	$ 1,292	$ 2,002	$ 1,257	$ 9,425
Capital leases	26	5	14	2	5
Operating leases	116	30	59	6	21
Purchase obligations	3,869	2,387	1,481	1	—
Other commercial commitments	3,639	899	1,532	613	595
Total	$ 21,626	$ 4,613	$ 5,088	$ 1,879	$ 10,046

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent. SCE&G has agreed to acquire an additional 5% ownership in the New Units and has included $850 million for this purpose in other commercial commitments. See also New Nuclear Construction in Note 10 to the consolidated financial statements.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

Unrecognized tax benefits of approximately $219 million have been excluded from the table above due to uncertainty as to the timing of future payments. For additional information, see Note 5 to the consolidated financial statements.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $11.1 million in 2016, and such annual payments are expected to be the same or increase to as much as $15.9 million in the future.

The Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. The Company, including Consolidated SCE&G, is also party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash collateral. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 6 to the consolidated financial statements. As of December 31, 2016, the Company had posted $29.0 million in cash collateral related to interest rate derivative contracts.

The Company has a legal obligation associated with the decommissioning and dismantling of Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

Financing Limits and Related Matters

Issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million.

GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018.

At December 31, 2016 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $400 million, $1.2 billion, of which $500 million relates to Fuel Company, and $200 million, respectively, which expire in December 2020. In addition, at December 31, 2016 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2016, the Company had no outstanding borrowings under its credit facilities, had approximately $941 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC-supported letters of credit, and held approximately $208 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. The Company's average short-term borrowings outstanding during 2016 were approximately $857 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2016, the Company’s long-term debt portfolio has a weighted average maturity of approximately 20 years and bears an average cost of 5.8%. Substantially all long-term debt bears fixed interest rates or is swapped to fixed.

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016, approximately $79.0 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2016, the Bond Ratio was 5.12.

Financing Activities

During 2016, net cash inflows related to financing activities totaled approximately $560 million, primarily associated with the proceeds from the issuance of long-term debt and short-term borrowings, partially offset by the payment of dividends.

On November 1, 2016, Consolidated SCE&G paid at maturity $100 million related to a nuclear fuel financing which had an imputed interest rate of 0.78%.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of the $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G’s construction program, to finance capital expenditures, and for general corporate purposes.

In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from this sale were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.70% junior subordinated notes at their face value.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $113 million in 2016, $253 million, net, in 2015 and approximately $95 million in 2014.

For additional information, see Note 4 to the consolidated financial statements.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2016, were as follows:

December 31,	2016	2015	2014	2013	2012
The Company	3.38	4.40	3.39	3.22	2.93
Consolidated SCE&G	3.66	3.69	3.77	3.48	3.29

The Company's ratio for 2015 reflects the impact of gains recorded upon the sale of certain subsidiaries. See Note 1 to the consolidated financial statements.

NEW NUCLEAR CONSTRUCTION MATTERS

For a discussion of developments related to new nuclear construction, see Note 2 and Note 10 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

The operations of the Company are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on financial condition, results of operations and cash flows. In addition, the conditions or requirements that will be imposed by regulatory or legislative proposals often cannot be predicted. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, recovery of such expenditures and costs are expected through existing ratemaking provisions.

For the three years ended December 31, 2016, capital expenditures for environmental control equipment at fossil fuel generating stations totaled $39.5 million. During this same period, expenditures were made for the construction and retirement of landfills and ash ponds, net of disposal proceeds, of approximately $32.8 million. In addition, expenditures were made to operate and maintain environmental control equipment at fossil plants of $9.5 million in 2016, $8.7 million in 2015 and $9.1 million in 2014, which are included in other operation and maintenance expense, and expenditures were made to handle waste ash, net of disposal proceeds, of $2.4 million in 2016, $1.3 million in 2015 and $1.6 million in 2014, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2016, 2015 and 2014 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $38.3 million for 2017 and $120 million for the four-year period 2018-2021. These expenditures are included in the Estimated Capital Expenditures table, discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to the Company's electric and gas systems, as well as impacts on employees and customers, the supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow for the protection of assets and the return of systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC, under Dodd-Frank, concerning recordkeeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCANA and any of its subsidiaries engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and other matters, including accounting; the DOE under the Federal Power Act as to use of emergency authority and coordination of all applicable federal authorizations and related environmental reviews to site an electric transmission facility; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings); the FERC as to issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters; and the DOE under the Federal Power Act as to use of emergency authority.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.

SCE&G and PSNC Energy	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively. The ORS and the NCUC are responsible for enforcement of federal and state pipeline safety requirements in South Carolina (SCE&G) and North Carolina (PSNC Energy), respectively.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system and certain facilities related to generation and distribution are subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Accounting for Rate Regulated Operations

Regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the criteria of accounting for rate-regulated utilities may no longer be met, and the write off of regulatory assets and liabilities could be required. Such an event could have a material effect on the results of operations, liquidity or financial position of the Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the regulatory assets and liabilities.

Generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write down in those assets could be required. It is not possible to predict whether any write-downs would be necessary and, if they were, the extent to which they would affect results of operations in the period in which they would be recorded. As of December 31, 2016, net investments in fossil/hydro and nuclear generation assets were approximately $2.2 billion and $5.0 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, estimates are recorded for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. The Company's accounts receivable included unbilled revenues of $178.9 million at December 31, 2016 and $129.1 million at December 31, 2015, compared to total revenues of $4.2 billion in 2016 and $4.4 billion in 2015.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates, less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Asset Retirement Obligations

AROs are accrued for legal obligations associated with the retirement of long-lived tangible assets that result from acquisition, construction, development and normal operation in accordance with applicable accounting guidance. These obligations are recognized at present value in the period in which they are incurred, and associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2016, the Company has recorded AROs of $199 million for nuclear plant decommissioning (as discussed above) and AROs of $359 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of precision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $22.9 million recorded in 2016 reflects the use of a 4.68% discount rate derived using a cash flow matching technique, and an assumed 7.50% long-term rate of return on plan assets. The Company believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2016 would have increased the Company's pension cost by $1.6 million and increased the pension obligation by $23.2 million. Further, had the assumed long-term rate of return on assets been 7.25%, the Company's pension cost for 2016 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2016, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.3%, 4.6%, 7.2% and 8.7%, respectively. The 2016 expected long-term rate of return of 7.50% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2017, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.1%, 5.4%, 6.9% and 8.2%, respectively. For 2017, it is anticipated that the long-term expected rate of return will be 7.25%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's and PSNC Energy's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after 2023. As a result, the significance of pension costs and the criticality of the related estimates will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future based on current market conditions and assumptions.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.78%, derived using a cash flow matching technique, and recorded a net cost for 2016 of $17.3 million. Had the selected discount rate been 4.53% (25 basis points lower than the discount rate referenced above), the expense for 2016 would have been $0.7 million higher and increased the obligation by $8.3 million. Because the plan provisions include “caps” on company per capita costs, and because employees hired after 2010 are responsible for the full cost of retiree medical benefits elected by them, health care cost inflation rate assumptions do not materially impact the net expense recorded.

Uncertain Income Tax Positions

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. See also Note 5 to the consolidated financial statements.

These income tax deductions and credits are considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, such estimated unrecognized tax benefits totaled $350 million ($219 million net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). The estimates of unrecognized tax benefits were computed with consideration as to whether the claims are (or are not) more likely than not to be sustained and with consideration of analyses of cumulative probabilities regarding potential outcomes. Such estimates involve significant management judgment and varying levels of precision. Changes in such estimates are required to be recorded as circumstances change and additional information regarding the claims and potential outcomes becomes available, and these changes could be significant.

However, as these uncertain tax positions primarily involve the timing of recognition of tax deductions rather than permanent tax attributes, the estimates regarding their recognition do not significantly impact the Company's effective tax rate. Further, the permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to the unrecognized tax benefits, have been deferred within regulatory assets. As such, the impacts of these significant accounting estimates, and changes therein, are primarily reflected on the balance sheet rather than in results of operations.

Upon resolution of the uncertainties, the Company will be required to re-pay any tax benefits claimed which are ultimately disallowed, along with interest on those amounts. In certain circumstances, which the Company considers to be remote, penalties for underpayment of income taxes could also be assessed. Such amounts could be significant and adversely affect cash flow and financial condition.

OTHER MATTERS

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. The Company does not engage in significant off-balance sheet financing or similar transactions, although it is party to various operating leases in the normal course of business for land, office space, furniture, vehicles, equipment, rail cars, a purchase power agreement, and airplanes.

Claims and Litigation

For a description of claims and litigation, see Note 10 to the consolidated financial statements.

Other

As Georgia's regulated provider, SCANA Energy provides service to customers considered to be low-income or that are otherwise unable to obtain natural gas service from other marketers. SCANA Energy provides this service at rates approved by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA's natural gas distribution and gas marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or placed under contract.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provide information about long-term debt issued by the Company and Consolidated SCE&G and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

The Company

December 31, 2016	**Expected Maturity Date**							
Millions of dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	12.5	721.7	11.1	360.2	489.0	4,789.7	6,384.3	7,040.6
Average Fixed Interest Rate (%)	4.21	6.01	4.40	6.33	4.64	5.73	5.70	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	125.0	147.0	142.7
Average Variable Interest Rate (%)	1.63	1.63	1.63	1.63	1.63	1.16	1.23	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	554.4	704.4	4.4	4.4	4.4	128.6	1,400.6	12.3
Average Pay Interest Rate (%)	2.91	2.22	6.17	6.17	6.17	4.57	2.74	—
Average Receive Interest Rate (%)	1.00	1.00	1.63	1.63	1.63	1.08	1.02	—

December 31, 2015	Expected Maturity Date							
Millions of dollars	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	111.5	10.6	719.8	9.1	358.3	4,673.0	5,882.3	6,336.2
Average Fixed Interest Rate (%)	1.16	4.42	6.02	4.73	6.35	5.63	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	129.4	151.4	145.5
Average Variable Interest Rate (%)	1.11	1.11	1.11	1.11	1.11	0.55	0.63	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	654.4	554.4	4.4	4.4	4.4	133.0	1,355.0	(72.1)
Average Pay Interest Rate (%)	2.89	2.91	6.17	6.17	6.17	4.62	3.10	—
Average Receive Interest Rate (%)	0.62	0.62	1.11	1.11	1.11	0.52	0.61	—

Consolidated SCE&G

December 31, 2016	Expected Maturity Date							
Millions of dollars	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	12.0	721.7	11.1	10.2	39.0	4,339.7	5,133.7	5,687.3
Average Fixed Interest Rate (%)	4.27	6.01	4.40	4.54	3.60	5.75	5.76	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	64.9
Average Variable Interest Rate (%)	—	—	—	—	—	0.76	0.76	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	550.0	700.0	—	—	—	71.4	1,321.4	31.7
Average Pay Interest Rate (%)	2.88	2.19	—	—	—	3.29	2.54	—
Average Receive Interest Rate (%)	1.00	1.00	—	—	—	0.64	0.98	—

December 31, 2015	Expected Maturity Date							
Millions of dollars	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	110.4	10.1	719.8	9.1	8.3	3,873.0	4,730.7	5,095.0
Average Fixed Interest Rate (%)	1.13	4.50	6.02	4.73	4.94	5.71	5.64	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	63.7
Average Variable Interest Rate (%)	—	—	—	—	—	0.03	0.03	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	650.0	550.0	—	—	—	71.4	1,271.4	(49.8)
Average Pay Interest Rate (%)	2.87	2.88	—	—	—	3.28	2.90	—
Average Receive Interest Rate (%)	0.61	0.61	—	—	—	0.01	0.58	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of long-term debt and interest rate derivatives, see the Liquidity and Capital Resources section in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes 4 and 6 to the consolidated financial statements.

Commodity Price Risk

The following table provides information about the Company's financial instruments, which are limited to financial positions of Energy Marketing and PSNC Energy, that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	2017	2018	2019
Futures - Long			
Settlement Price (a)	3.65	3.43	—
Contract Amount (b)	92.6	15.4	—
Fair Value (b)	102.3	16.5	—
Futures - Short			
Settlement Price (a)	3.65	3.43	—
Contract Amount (b)	49.7	8.0	—
Fair Value (b)	51.6	8.3	—
Options - Purchased Call (Long)			
Strike Price (a)	1.95	—	—
Contract Amount (b)	13.7	—	—
Fair Value (b)	2.6	—	—
Swaps - Commodity			
Pay fixed/receive variable (b)	13.9	8.0	1.0
Average pay rate (a)	3.4075	3.4326	2.9667
Average received rate (a)	3.6240	3.2042	3.0954
Fair Value (b)	14.8	7.5	1.1
Pay variable/receive fixed (b)	30.4	11.3	0.8
Average pay rate (a)	3.6234	3.2431	3.1277
Average received rate (a)	3.2387	3.3488	2.9851
Fair Value (b)	27.1	11.7	0.8
Swaps - Basis			
Pay variable/receive variable (b)	1.5	0.8	0.3
Average pay rate (a)	3.7218	3.4697	3.1904
Average received rate (a)	3.6529	3.4218	3.1234
Fair Value (b)	1.5	0.8	0.3

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

SCANA Corporation and Subsidiaries
Consolidated Balance Sheets

December 31, (Millions of dollars)	2016	2015
Assets		
Utility Plant In Service	$ 13,444	$ 12,883
Accumulated Depreciation and Amortization	(4,446)	(4,307)
Construction Work in Progress	4,845	4,051
Nuclear Fuel, Net of Accumulated Amortization	271	308
Goodwill	210	210
Utility Plant, Net	14,324	13,145
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $138 and $124	276	280
Assets held in trust, net-nuclear decommissioning	123	115
Other investments	76	71
Nonutility Property and Investments, Net	475	466
Current Assets:		
Cash and cash equivalents	208	176
Receivables:		
Customer, net of allowance for uncollectible accounts of $6 and $5	616	505
Income taxes	142	—
Other	127	227
Inventories:		
Fuel	136	164
Materials and supplies	155	148
Prepayments	105	115
Other current assets	17	43
Total Current Assets	1,506	1,378
Deferred Debits and Other Assets:		
Regulatory assets	2,130	1,937
Other	272	220
Total Deferred Debits and Other Assets	2,402	2,157
Total	$ 18,707	$ 17,146

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2016	2015
Capitalization and Liabilities		
Common Stock - no par value, 142.9 million shares outstanding for all periods presented	$ 2,390	$ 2,390
Retained Earnings	3,384	3,118
Accumulated Other Comprehensive Loss	(49)	(65)
Total Common Equity	5,725	5,443
Long-Term Debt, Net	6,473	5,882
Total Capitalization	12,198	11,325
Current Liabilities:		
Short-term borrowings	941	531
Current portion of long-term debt	17	116
Accounts payable	404	590
Customer deposits and customer prepayments	168	137
Taxes accrued	201	242
Interest accrued	84	83
Dividends declared	80	76
Derivative financial instruments	35	50
Other	135	127
Total Current Liabilities	2,065	1,952
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	2,159	1,907
Asset retirement obligations	558	520
Pension and postretirement benefits	373	315
Unrecognized tax benefits	219	44
Regulatory liabilities	930	855
Other	205	228
Total Deferred Credits and Other Liabilities	4,444	3,869
Commitments and Contingencies (Note 10)	—	—
Total	$ 18,707	$ 17,146

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Income

Years Ended December 31, (Millions of dollars, except per share amounts)	2016	2015	2014
Operating Revenues:			
Electric	$ 2,614	$ 2,551	$ 2,622
Gas-regulated	788	811	1,028
Gas-nonregulated	825	1,018	1,301
Total Operating Revenues	4,227	4,380	4,951
Operating Expenses:			
Fuel used in electric generation	576	660	793
Purchased power	64	52	81
Gas purchased for resale	1,054	1,287	1,729
Other operation and maintenance	755	715	728
Depreciation and amortization	371	358	384
Other taxes	254	234	229
Total Operating Expenses	3,074	3,306	3,944
Gain on sale of CGT, net of transaction costs	—	234	—
Operating Income	1,153	1,308	1,007
Other Income (Expense):			
Other income	64	75	122
Other expense	(38)	(60)	(64)
Gain on sale of SCI, net of transaction costs	—	107	—
Interest charges, net of allowance for borrowed funds used during construction of $19, $15 and $16	(342)	(318)	(312)
Allowance for equity funds used during construction	29	27	33
Total Other Expense	(287)	(169)	(221)
Income Before Income Tax Expense	866	1,139	786
Income Tax Expense	271	393	248
Net Income	$ 595	$ 746	$ 538
Earnings Per Share of Common Stock	$ 4.16	$ 5.22	$ 3.79
Weighted Average Common Shares Outstanding (millions)	142.9	142.9	141.9
Dividends Declared Per Share of Common Stock	$ 2.30	$ 2.18	$ 2.10

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31, (Millions of dollars)	2016	2015	2014
Net Income	$ 595	$ 746	$ 538
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $2, $(7) and $(9)	4	(12)	(14)
Cash flow hedging activities reclassified to interest expense, net of tax of $4, $4 and $4	7	7	7
Cash flow hedging activities reclassified to gas purchased for resale, net of tax of $4, $9 and $(2)	6	15	(4)
Net unrealized gains (losses) on cash flow hedging activities	17	10	(11)
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $-, $- and $(3)	—	—	(5)
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	(1)	—	1
Net deferred costs of employee benefit plans	(1)	—	(4)
Other Comprehensive Income (Loss)	16	10	(15)
Total Comprehensive Income	$ 611	$ 756	$ 523

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2016	2015	2014
Cash Flows From Operating Activities:			
Net Income	$ 595	$ 746	$ 538
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain on sale of subsidiaries	—	(355)	—
Deferred income taxes, net	242	(31)	235
Depreciation and amortization	389	368	403
Amortization of nuclear fuel	57	46	45
Allowance for equity funds used during construction	(29)	(27)	(33)
Carrying cost recovery	(17)	(12)	(9)
Changes in certain assets and liabilities:			
Receivables	(112)	188	(33)
Income tax receivable	(142)	—	—
Inventories	(43)	(16)	(62)
Prepayments	11	211	(235)
Regulatory assets	(114)	(31)	(138)
Regulatory liabilities	(2)	(1)	(104)
Accounts payable	44	(78)	36
Unrecognized tax benefits	175	31	10
Taxes accrued	(41)	61	(24)
Pension and other postretirement benefits	51	(6)	133
Derivative financial instruments	(9)	(9)	18
Other assets	(44)	(3)	(35)
Other liabilities	81	(23)	(15)
Net Cash Provided From Operating Activities	1,092	1,059	730
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,579)	(1,153)	(1,092)
Proceeds from sale of subsidiaries	—	647	—
Proceeds from investments (including derivative collateral returned)	860	1,117	347
Purchase of investments (including derivative collateral posted)	(788)	(1,018)	(475)
Payments upon interest rate derivative contract settlement	(113)	(263)	(95)
Proceeds from interest rate derivative contract settlement	—	10	—
Net Cash Used For Investing Activities	(1,620)	(660)	(1,315)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	—	14	98
Proceeds from issuance of long-term debt	592	491	294
Repayments of long-term debt	(117)	(166)	(54)
Dividends	(325)	(309)	(294)
Short-term borrowings, net	410	(387)	542
Deferred financing costs	—	(3)	—
Net Cash Provided From (Used For) Financing Activities	560	(360)	586
Net Increase in Cash and Cash Equivalents	32	39	1
Cash and Cash Equivalents, January 1	176	137	136
Cash and Cash Equivalents, December 31	$ 208	$ 176	$ 137
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $19, $15 and $16)	$ 328	$ 306	$ 301
—Income taxes paid	229	184	299
—Income taxes received	166	—	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	109	244	180
Capital leases	15	6	5

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Changes in Common Equity

	Common Stock				Accumulated Other Comprehensive Income (Loss)			
Millions	**Shares**	**Outstanding Amount**	**Treasury Amount**	**Retained Earnings**	**Gains (Losses) Cash Flow Hedges**	**Deferred Employee Benefit Plans**	**Total AOCI**	**Total**
Balance as of January 1, 2014	141	$ 2,289	$ (9)	$ 2,444	$ (52)	$ (8)	$ (60)	$ 4,664
Net Income				538				538
Other Comprehensive Income (Loss)								
Losses arising during the period					(14)	(5)	(19)	(19)
Losses/amortization reclassified from AOCI					3	1	4	4
Total Comprehensive Income (Loss)				538	(11)	(4)	(15)	523
Issuance of Common Stock	2	99	(1)					98
Dividends Declared				(298)				(298)
Balance as of December 31, 2014	143	$ 2,388	(10)	2,684	(63)	(12)	(75)	4,987
Net Income				746				746
Other Comprehensive Income (Loss)								
Losses arising during the period					(12)	—	(12)	(12)
Losses/amortization reclassified from AOCI					22	—	22	22
Total Comprehensive Income				746	10	—	10	756
Issuance of Common Stock	—	14	(2)					12
Dividends Declared				(312)				(312)
Balance as of December 31, 2015	143	$ 2,402	(12)	3,118	(53)	(12)	(65)	5,443
Net Income				595				595
Other Comprehensive Income (Loss)								
Losses arising during the period					4	(1)	3	3
Losses/amortization reclassified from AOCI					13	—	13	13
Total Comprehensive Income (Loss)				595	17	(1)	16	611
Issuance of Common Stock	—	—	—					—
Dividends Declared				(329)				(329)
Balance as of December 31, 2016	143	$ 2,402	$ (12)	$ 3,384	$ (36)	$ (13)	$ (49)	$ 5,725

Dividends declared per share of common stock were $2.30, $2.18 and $2.10 for 2016, 2015 and 2014, respectively.

See Notes to Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of comprehensive income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

South Carolina Electric & Gas Company and Affiliates
Consolidated Balance Sheets

December 31, (Millions of dollars)	2016	2015
Assets		
Utility Plant In Service	$ 11,510	$ 11,153
Accumulated Depreciation and Amortization	(3,991)	(3,869)
Construction Work in Progress	4,813	3,997
Nuclear Fuel, Net of Accumulated Amortization	271	308
Utility Plant, Net ($756 and $700 related to VIEs)	12,603	11,589
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	69	68
Assets held in trust, net-nuclear decommissioning	123	115
Other investments	3	1
Nonutility Property and Investments, Net	195	184
Current Assets:		
Cash and cash equivalents	164	130
Receivables:		
Customer, net of allowance for uncollectible accounts of $3 and $3	378	324
Affiliated companies	16	22
Income taxes	53	—
Other	94	202
Inventories:		
Fuel	83	98
Materials and supplies	143	136
Prepayments	88	92
Other current assets	1	15
Total Current Assets ($85 and $88 related to VIEs)	1,020	1,019
Deferred Debits and Other Assets:		
Regulatory assets	2,030	1,857
Other	243	116
Total Deferred Debits and Other Assets ($52 and $53 related to VIEs)	2,273	1,973
Total	$ 16,091	$ 14,765

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2016	2015
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,860	$ 2,760
Retained Earnings	2,481	2,265
Accumulated Other Comprehensive Loss	(3)	(3)
Total Common Equity	5,338	5,022
Noncontrolling interest	134	129
Total Equity	5,472	5,151
Long-Term Debt, net	5,154	4,659
Total Capitalization	10,626	9,810
Current Liabilities:		
Short-term borrowings	804	420
Current portion of long-term debt	12	110
Accounts payable	247	469
Affiliated payables	122	113
Customer deposits and customer prepayments	126	93
Taxes accrued	195	299
Interest accrued	68	66
Dividends declared	79	75
Derivative financial instruments	28	34
Other	55	61
Total Current Liabilities	1,736	1,740
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,939	1,732
Asset retirement obligations	522	488
Pension and postretirement benefits	232	186
Unrecognized tax benefits	236	44
Regulatory liabilities	695	635
Other	89	113
Other - affiliate	16	17
Total Deferred Credits and Other Liabilities	3,729	3,215
Commitments and Contingencies (Note 10)	—	—
Total	$ 16,091	$ 14,765

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Comprehensive Income

For the Years Ended December 31, (Millions of dollars)	2016	2015	2014
Operating Revenues:			
Electric	$ 2,614	$ 2,551	$ 2,621
Electric - nonconsolidated affiliate	5	6	8
Gas	366	372	461
Gas - nonconsolidated affiliate	1	1	1
Total Operating Revenues	2,986	2,930	3,091
Operating Expenses:			
Fuel used in electric generation	472	559	644
Fuel used in electric generation - nonconsolidated affiliate	104	102	155
Purchased power	64	52	81
Gas purchased for resale	174	162	210
Gas purchased for resale - nonconsolidated affiliate	9	31	73
Other operation and maintenance	403	380	382
Other operation and maintenance - nonconsolidated affiliate	211	199	193
Depreciation and amortization	302	294	315
Other taxes	227	211	202
Other taxes - nonconsolidated affiliate	7	6	6
Total Operating Expenses	1,973	1,996	2,261
Operating Income	1,013	934	830
Other Income (Expense):			
Other income	29	31	80
Other expenses	(24)	(31)	(34)
Interest charges, net of allowance for borrowed funds used during construction of $18, $14 and $14	(270)	(248)	(228)
Allowance for equity funds used during construction	26	25	28
Total Other Expense	(239)	(223)	(154)
Income Before Income Tax Expense	774	711	676
Income Tax Expense	248	231	218
Net Income and Total Comprehensive Income	526	480	458
Less Net Income and Total Comprehensive Income Attributable to Noncontrolling Interest	13	14	12
Earnings and Comprehensive Income Available to Common Shareholder	$ 513	$ 466	$ 446
Dividends Declared on Common Stock	$ 305	$ 285	$ 272

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2016	2015	2014
Cash Flows From Operating Activities:			
Net income	$ 526	$ 480	$ 458
Adjustments to reconcile net income to net cash provided from operating activities:			
Deferred income taxes, net	207	8	187
Depreciation and amortization	310	294	318
Amortization of nuclear fuel	57	46	45
Allowance for equity funds used during construction	(26)	(25)	(28)
Carrying cost recovery	(17)	(12)	(9)
Changes in certain assets and liabilities:			
Receivables	(47)	85	51
Receivables - affiliate	(3)	16	(90)
Income tax receivable	(53)	—	—
Inventories	(35)	(24)	(52)
Prepayments	(4)	70	(89)
Regulatory assets	(94)	(29)	(116)
Other regulatory liabilities	(5)	(3)	(103)
Accounts payable	8	11	(49)
Accounts payable - affiliate	13	(17)	63
Unrecognized tax benefits	192	31	10
Taxes accrued	(104)	129	(53)
Pension and other postretirement benefits	39	(5)	106
Other assets	(99)	57	(15)
Other liabilities	58	(28)	16
Other liabilities - affiliate	(1)	(6)	(9)
Net Cash Provided From Operating Activities	922	1,078	641
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,399)	(1,008)	(934)
Proceeds from investments and sales of assets (including derivative collateral returned)	794	975	275
Purchase of investments (including derivative collateral posted)	(740)	(887)	(381)
Payments upon interest rate derivative contract settlement	(113)	(263)	(95)
Proceeds from interest rate derivative contract settlement	—	10	—
Proceeds from investment in affiliate	9	71	—
Investment in affiliate	—	—	(80)
Net Cash Used For Investing Activities	(1,449)	(1,102)	(1,215)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	494	491	294
Repayment of long-term debt	(112)	(11)	(48)
Dividends	(301)	(285)	(260)
Short-term borrowings, net	384	(289)	458
Short-term borrowings-nonconsolidated affiliate, net	(4)	(50)	56
Contribution from parent	100	204	89
Return of capital to parent	—	(4)	(7)
Deferred financing costs	—	(2)	—
Net Cash Provided From Financing Activities	561	54	582
Net Increase in Cash and Cash Equivalents	34	30	8
Cash and Cash Equivalents, January 1	130	100	92
Cash and Cash Equivalents, December 31	$ 164	$ 130	$ 100
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $18, $14 and $14)	$ 251	$ 228	$ 210
—Income taxes paid	289	89	177
—Income taxes received	189	84	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	95	230	151
Capital leases	14	6	5

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Changes in Equity

Millions	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total Equity
Balance at January 1, 2014	40	$ 2,479	$ 1,896	$ (3)	$ 117	$ 4,489
Earnings available for common shareholder			446		12	458
Deferred cost of employee benefit plans, net of tax $-				—		—
Total Comprehensive Income			446	—	12	458
Capital contributions from parent		81			1	82
Cash dividends declared			(265)		(7)	(272)
Balance at December 31, 2014	40	2,560	2,077	(3)	123	4,757
Earnings Available for Common Shareholder			466		14	480
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			466	—	14	480
Capital contributions from parent		200			—	200
Cash dividends declared			(278)		(8)	(286)
Balance at December 31, 2015	40	2,760	2,265	(3)	129	5,151
Earnings Available for Common Shareholder			513		13	526
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			513	—	13	526
Capital contributions from parent		100			—	100
Cash dividends declared			(297)		(8)	(305)
Balance at December 31, 2016	40	$ 2,860	$ 2,481	$ (3)	$ 134	$ 5,472

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
South Carolina Electric & Gas Company and Affiliates
Notes to Consolidated Financial Statements

The following notes to the consolidated financial statements are a combined presentation. Except as otherwise indicated herein, each note applies to the Company and Consolidated SCE&G; however, Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation or its subsidiaries (other than Consolidated SCE&G).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

The Company

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina, the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia and conducts other energy-related business.

The accompanying consolidated financial statements reflect the accounts of SCANA, the following wholly-owned subsidiaries, and subsidiaries that formerly were wholly-owned during the periods presented.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	ServiceCare, Inc.
South Carolina Generating Company, Inc.	SCANA Services, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Corporate Security Services, Inc.
	SCANA Communications Holdings, Inc.

SCANA reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance. Discussions regarding the Company's financial results necessarily include the results of Consolidated SCE&G.

Consolidated SCE&G

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs) and accordingly, Consolidated SCE&G's consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. As a result, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's consolidated financial statements. Intercompany balances and transactions between SCE&G, Fuel Company and GENCO have been eliminated in consolidation.

GENCO owns a coal-fired electric generating station with a 605 MW net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $485 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Dispositions

In the first quarter of 2015, SCANA sold CGT and SCI. CGT was an interstate natural gas pipeline regulated by FERC that transported natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provided fiber optic communications and other services and built, managed and leased communications towers in several southeastern states, and it was sold to Spirit Communications. These sales resulted in recognition of pre-tax gains totaling approximately $342 million. The pre-tax gain from the sale of CGT is included within Operating Income and the pre-tax gain from the sale of SCI is included within Other Income (Expense) on the Company's consolidated statement of income.

CGT and SCI operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment and were included within All Other in Note 12. The sales of CGT and SCI did not represent a strategic shift that had a major effect on the Company's operations; therefore, these sales did not meet the criteria for classification as discontinued operations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current presentation, as follows:

Statements of Cash Flows - For the Company and Consolidated SCE&G, non-cash changes in fair value of interest rate swaps were reclassified as an offset to the changes in certain assets and liabilities section within the reconciliations of Net Income to Net Cash Provided From Operating Activities as follows:

	December 31,	
Millions of dollars	2015	2014
Derivative financial instruments	$ (174)	$ 207
Regulatory assets	179	(234)
Regulatory liabilities	4	(29)
Other assets	(15)	32
Other liabilities	6	24

In addition, due to insignificance, the caption for Losses from equity method investments has been eliminated, and the amounts have been reclassified and included within the caption of Changes in Other assets.

The reclassifications above had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the consolidated statements of cash flows.

Statements of Comprehensive Income - For Consolidated SCE&G, operating revenues and operating expenses from transactions with nonconsolidated affiliates are presented separately. A detail of such transactions are included in Note 11.

Segment of Business Information Disclosure - For the Company, the Gas Marketing segment includes the information formerly reported in two separate marketing segments. See Note 12 for the required disclosures.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset’s life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company's regulated subsidiaries calculated AFC using average composite rates of 5.3% for 2016, 6.1% for 2015, and 7.2% for 2014. Consolidated SCE&G calculated AFC using average composite rates of 4.7% for 2016, 5.6% for 2015, and 6.5% for 2014. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. In addition, CGT was sold in the first quarter of 2015 (see Dispositions herein) and excluded from the 2015 calculation of composite weighted average depreciation rates. The composite weighted average depreciation rates for utility plant assets were as follows:

	2016	2015	2014
SCE&G	2.56%	2.55%	2.85%
GENCO	2.66%	2.66%	2.66%
CGT	—	—	2.11%
PSNC Energy	2.90%	2.94%	2.98%
Weighted average of above	2.61%	2.61%	2.84%
Consolidated SCE&G	2.56%	2.56%	2.84%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in Fuel used in electric generation and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2016		2015	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.3 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 634.4 million	—	$ 620.4 million	—
Construction work in progress	$ 167.7 million	$ 4.2 billion	$ 214.6 million	$ 3.4 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Unit 1 and the New Units. These amounts totaled $76.2 million at December 31, 2016 and $178.8 million at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2016, and 2015, SCE&G incurred $23.8 million and $16.5 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, SCE&G accrues $17.2 million annually for its portion of the nuclear refueling outages scheduled from the spring of 2014 through the spring of 2020. Refueling outage costs incurred for which SCE&G was responsible totaled $26.8 million for the Fall 2015 outage and $1.8 million in 2016 in preparation for the Spring 2017 outage.

Goodwill

The Company considers certain amounts categorized by FERC as acquisition adjustments to be goodwill. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. Accounting guidance adopted by the Company gives it the option to perform a qualitative assessment of impairment ("step zero"). Based on this qualitative assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with a two-step quantitative assessment. If the quantitative assessment becomes necessary, step one requires estimation of the fair value of the reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Should a write-down be required, such a charge would be treated as an operating expense.

For each period presented, assets with a carrying value of $210 million for PSNC Energy (Gas Distribution segment), net of a writedown of $230 million taken in 2002, were classified as goodwill. The Company utilized the step zero qualitative assessment in its evaluation as of January 1, 2017 and was not required to use the two-step quantitative assessment. In evaluations for preceding periods, the Company's step one assessment utilized the assistance of an independent appraisal in determining its estimate of fair value. In such evaluations, step one indicated no impairment, and no impairment charges were recorded.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Temporary cash investments having original maturities of three months or less at time of purchase are considered to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.
Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable.

PSNC Energy utilizes an asset management and supply service agreement with a counterparty for certain natural gas storage facilities. The counterparty held, through an agency relationship, 40% and 46% of PSNC Energy’s natural gas inventory at December 31, 2016 and December 31, 2015, respectively, with a carrying value of $9.8 million and $17.7 million, respectively. Under the terms of this agreement, PSNC Energy receives storage asset management fees of which 75% are credited to rate payers. PSNC Energy expects to replace this agreement when it expires on March 31, 2017.

Income Taxes

SCANA files consolidated federal income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary’s current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company’s regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Consolidated SCE&G is included in the consolidated federal income tax returns of SCANA. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

The Company’s rate-regulated utilities, including Consolidated SCE&G, record costs that have been or are expected to be allowed in the ratemaking process in periods different from the periods in which the costs would be charged to expense, or record revenues in periods different from the periods in which the revenues would be recorded, by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations for refunds to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as Receivables - Customer or Customer deposits and customer prepayments, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Premiums, discounts and debt issuance costs are presented within long-term debt and are amortized as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

Revenues and expenses arising from regulated businesses and, in the case of the Company, retail natural gas marketing businesses (including those activities of segments described in Note 12) are presented within Operating Income, and all other activities are presented within Other Income (Expense). Consistent with this presentation, the Company presents the 2015 gain on the sale of CGT within Operating Income and the 2015 gain on the sale of SCI within Other Income (Expense).

Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $178.9 million at December 31, 2016 and $129.1 million at December 31, 2015 for the Company. Unbilled revenues totaled $117.6 million at December 31, 2016 and $101.5 million at December 31, 2015 for Consolidated SCE&G.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy’s PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

Basic earnings per share are computed by dividing net income by the weighted average number of common shares outstanding for the period. When applicable, diluted earnings per share are computed using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method.

New Accounting Matters

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most earlier revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018. The guidance permits adoption using a retrospective method, with options to elect certain practical expedients, or recognition of a cumulative effect in the year of initial adoption. The Company and Consolidated SCE&G have not determined which method of adoption will be employed or what practical expedients may be elected. The Company and Consolidated SCE&G have not determined the impact this guidance will have on their respective financial statements. However, the identification of implementation project team members and the analysis of contracts with customers to which the guidance might be applicable, particularly large customer contracts, have begun. In addition, activities of the FASB's Transition Resource Group for Revenue Recognition are being monitored, particularly as they relate to the required treatment under the standard of contributions in aid of construction, alternative revenue programs and the collectibility of revenue of utilities subject to rate regulation.

In May 2015, the FASB issued accounting guidance removing the requirement to categorize within the fair value hierarchy investments for which fair values are estimated using the NAV practical expedient. Disclosures about investments in certain entities that calculate NAV per share are limited under this guidance to those investments for which the entity has elected to estimate the fair value using the NAV practical expedient. The Company and Consolidated SCE&G elected to adopt this guidance on a retrospective basis. The adoption resulted in the reclassification of fair value related to the pension plan's investment in the common collective trust, joint venture interest, and limited partnership as of December 31, 2015. See Note 8.

In July 2015, the FASB issued accounting guidance intended to simplify the measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. The Company and Consolidated SCE&G expect to adopt this guidance in the first quarter of 2017 and do not expect it to have a significant impact on their respective financial statements.

In January 2016, the FASB issued accounting guidance that will change how entities measure certain equity investments and financial liabilities, among other things. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018 and have determined adoption of this guidance will not have a significant impact on their respective financial statements.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over 12 months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily on the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for years beginning in 2019. The Company and Consolidated SCE&G have not determined what impact this guidance will have on their respective financial statements. However, the identification of implementation project team members and the initial identification and analysis of leasing and related contracts to which the guidance might be applicable have begun. In addition, the Company and Consolidated SCE&G have begun evaluating certain third party software tools that may assist with this implementation and ongoing compliance.

In March 2016, the FASB issued accounting guidance changing how companies account for certain aspects of share-based payments to employees. Entities are required to recognize the income tax effects of awards in the income statement when the awards vest or are settled. The Company and Consolidated SCE&G adopted this guidance in the fourth quarter of 2016 and, based on the nature of their share-based awards practices, the adoption had no impact on their respective financial statements.

In June 2016, the FASB issued accounting guidance requiring the use of a current expected credit loss impairment model for certain financial instruments. The new model is applicable to trade receivables and most debt instruments, among other financial instruments, and is intended to result in certain impairment losses being recognized earlier than under current guidance. The Company and Consolidated SCE&G must adopt this guidance beginning in 2020, including interim periods, though the guidance may be adopted in 2019. The Company and Consolidated SCE&G have not determined when this guidance will be adopted or what impact it will have on their respective financial statements.

In August 2016, the FASB issued accounting guidance to reduce diversity in cash flow classification related to certain transactions. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018 and do not anticipate that its adoption will impact their respective financial statements.

In October 2016, the FASB issued accounting guidance related to the tax effects of intra-entity asset transfers of assets other than inventory. An entity will be required to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The Company and Consolidated SCE&G expect to adopt this guidance in the first quarter 2017 and it is not expected to have a material impact on their respective financial statements.

In November 2016, the FASB issued accounting guidance related to the presentation of restricted cash on the statement of cash flows. The guidance is effective for years beginning in 2018 and the Company and Consolidated SCE&G expect no impact on their respective financial statements.

In January 2017, the FASB issued accounting guidance to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test. The same one-step impairment test will be applied to goodwill at all reporting units, even those with zero or negative carrying amounts. The guidance is effective for years beginning in 2020, though early adoption after January 1, 2017 is allowed. The Company and Consolidated SCE&G have not determined when this guidance will be adopted but do not anticipate that adoption will have a material impact on their respective financial statements.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments were fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G, ORS, and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million ($.12 per share) in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million ($.06 per share) with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

By order dated April 29, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties to decrease the total fuel cost component of retail electric rates. SCE&G reduced the total fuel cost component of retail electric rates to reflect lower projected fuel costs and to eliminate over-collected balances of approximately $61 million for base fuel and environmental costs over a 12-month period beginning with the first billing cycle of May 2016. SCE&G also began to recover projected DER program costs of approximately $6.9 million beginning with the first billing cycle of May 2016.

In October 2016, the SCPSC initiated its 2017 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 6, 2017.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G removes from rate base certain deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $14.0 million and $9.5 million during 2016 and 2015, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these deferred income tax assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2016	First billing cycle of May	$37.6 million
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G's request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider is designed to allow SCE&G to recover projected pension costs, including under-collections, over a 12-month period, beginning with the first billing cycle in May 2016.

In January 2017, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved the filing would allow recovery of $37.0 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed ROE. The SCPSC has approved recovery of the following amounts.

Year	Increase	Effective for bills rendered on and after	Amount	Allowed ROE
2016	2.7%	November 27	$64.4 million	10.50% *
2015	2.6%	October 30	$64.5 million	11.00%
2014	2.8%	October 30	$66.2 million	11.00%

*Applied prospectively for purposes of calculating revised rates under the BLRA on and after January 1, 2016.

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time. See also New Nuclear Construction in Note 10.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. SCE&G cannot determine when the SCPSC will issue its order in this matter or if that order will be appealed.

Gas - SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2016	1.2% Increase	$4.1 million
2015	No change	—
2014	0.6% Decrease	$2.6 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2016, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Gas - PSNC Energy

PSNC Energy's Rider D rate mechanism allows it to recover from customers all prudently incurred gas costs and certain related uncollectible expenses as well as losses on negotiated gas and transportation sales.

PSNC Energy establishes rates using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

On October 28, 2016, the NCUC granted PSNC Energy a net annual increase of approximately $19.1 million, or 4.39%, in rates and charges to customers, and set PSNC Energy's authorized ROE at 9.7%. In addition, PSNC Energy was authorized to implement a tracker that provides for biannual rate adjustments to recover the revenue requirement associated with integrity management plant investment and associated costs resulting from prevailing federal standards for pipeline integrity and safety that are not otherwise included in current base rates. The new rates are effective for services rendered on or after November 1, 2016.

In November 2016, in connection with PSNC Energy's 2016 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2016.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, the Company and Consolidated SCE&G have recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	The Company		Consolidated SCE&G	
	December 31,		December 31,	
Millions of dollars	2016	2015	2016	2015
Regulatory Assets:				
Accumulated deferred income taxes	$ 316	$ 298	$ 307	$ 291
AROs and related funding	425	405	403	384
Deferred employee benefit plan costs	342	325	309	295
Deferred losses on interest rate derivatives	620	535	620	535
Unrecovered plant	117	127	117	127
Environmental remediation costs	32	42	26	35
DSM Programs	59	61	59	61
Pipeline integrity management costs	33	19	6	4
Carrying costs on deferred tax assets related to nuclear construction	32	18	32	18
Deferred storm damage costs	20	—	20	—
Deferred costs related to uncertain tax position	15	—	15	—
Other	119	107	116	107
Total Regulatory Assets	$ 2,130	$ 1,937	$ 2,030	$ 1,857
Regulatory Liabilities:				
Asset removal costs	$ 755	$ 732	$ 529	$ 519
Deferred gains on interest rate derivatives	151	96	151	96
Other	24	27	15	20
Total Regulatory Liabilities	$ 930	$ 855	$ 695	$ 635

Accumulated deferred income tax liabilities that arise from utility operations that have not been included in customer rates are recorded as a regulatory asset. A substantial portion of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 11 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G or PSNC Energy, and are expected to be recovered over periods of up to approximately 18 years.

DSM Programs represent SCE&G's deferred costs associated with such programs, and such deferred costs are currently being recovered over approximately five years through an approved rate rider.

Pipeline integrity management costs represent costs incurred to comply with regulatory requirements related to natural gas pipelines located near moderate to high density populations. PSNC Energy will recover costs totaling $20.3 million over a five-year period beginning November 2016, and remaining costs of $7.0 million have been deferred pending future approval of rate recovery. SCE&G began amortizing $1.9 million of such costs annually in November 2015.

Carrying costs on deferred tax assets related to nuclear construction are calculated on accumulated deferred income tax assets associated with the New Units which are not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs will be amortized over ten years beginning in approximately 2020.

Deferred storm damage costs represent costs incurred in excess of amounts previously collected through SCE&G's SCPSC-approved storm damage reserve, and for which SCE&G expects to receive future recovery through customer rates.

Deferred costs related to uncertain tax position primarily represent the estimated amounts of domestic production activities deductions foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest expense and other costs arising from this uncertain tax position. SCE&G's current customer rates reflect the availability of domestic production activities deductions. These net deferred costs are expected to be recovered through utility rates following ultimate resolution of the claims. See also Note 5.

Various other regulatory assets are expected to be recovered through rates over periods up to 2047.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company or Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's and Consolidated SCE&G's financial statements in the period the write-off would be recorded.

3. COMMON EQUITY

SCANA's articles of incorporation do not limit the dividends that may be paid on its common stock, and the articles of incorporation of each of SCANA's subsidiaries contain no such limitations on their respective common stock. However, SCE&G's bond indenture and PSNC Energy's note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company and, in the case of SCE&G, Consolidated SCE&G consider to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016 and 2015, retained earnings of approximately $79.0 million and $72.4 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

Authorized shares of common stock were 200 million as of December 31, 2016 and 2015.

SCANA issued no common stock during the year ended December 31, 2016. SCANA issued common stock valued at $14.3 million (when issued) during the year ended December 31, 2015, to satisfy the requirements of deferred compensation and dividend reinvestment plans.

Authorized shares of SCE&G common stock were 50 million as of December 31, 2016 and 2015. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2016 and 2015.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

The Company

December 31, Dollars in millions	Maturity	2016 Balance	2016 Rate	2015 Balance	2015 Rate
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%
SCANA Senior Notes (unsecured) (a)	2017 - 2034	79	1.63%	84	1.11%
SCE&G First Mortgage Bonds (secured)	2018 - 2065	4,840	5.79%	4,340	5.78%
GENCO Notes (secured)	2017 - 2024	213	5.93%	220	5.92%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.51%	122	3.51%
PSNC Energy Senior Debentures and Notes	2020 - 2046	450	5.53%	350	5.93%
Nuclear Fuel Financing	2016	—	—%	100	0.78%
Other	2017 - 2027	27	2.76%	18	2.72%
Total debt		6,531		6,034	
Current maturities of long-term debt		(17)		(116)	
Unamortized discount, net		(1)		—	
Unamortized debt issuance costs		(40)		(36)	
Total long-term debt, net		$ 6,473		$ 5,882	

Consolidated SCE&G

December 31, Dollars in millions	Maturity	2016 Balance	2016 Rate	2015 Balance	2015 Rate
First Mortgage Bonds (secured)	2018 - 2065	$ 4,840	5.79%	$ 4,340	5.78%
GENCO Notes (secured)	2017 - 2024	213	5.93%	220	5.92%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.51%	122	3.51%
Nuclear Fuel Financing	2016	—	—%	100	0.78%
Other	2017 - 2027	26	2.76%	17	2.63%
Total debt		5,201		4,799	
Current maturities of long-term debt		(12)		(110)	
Unamortized premium, net		1		2	
Unamortized debt issuance costs		(36)		(32)	
Total long-term debt, net		$ 5,154		$ 4,659	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%).
(b) Includes variable rate debt of $67.8 million at December 31, 2016 (rate of 0.76%) and 2015 (rate of 0.03%) which are hedged by fixed swaps.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from this sale were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

The Company's long-term debt maturities will be $17 million in 2017, $726 million in 2018, $15 million in 2019, $365 million in 2020 and $493 million in 2021. These amounts include, for Consolidated SCE&G, $12 million in 2017, $722 million in 2018, $11 million in 2019, $10 million in 2020 and $39 million in 2021.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2016, the Bond Ratio was 5.12.

Lines of Credit and Short-Term Borrowings

At December 31, 2016 and 2015, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

December 31, 2016								
Millions of dollars		**Total**		**SCANA**		**SCE&G**		**PSNC Energy**
Lines of credit:								
Five-year, expiring December 2020	$	1,300.0	$	400.0	$	700.0	$	200.0
Fuel Company five-year, expiring December 2020	$	500.0		—	$	500.0		—
Three-year, expiring December 2018	$	200.0		—	$	200.0		—
Total committed long-term	$	2,000.0	$	400.0	$	1,400.0	$	200.0
Outstanding commercial paper (270 or fewer days)	$	940.5	$	64.4	$	804.3	$	71.8
Weighted average interest rate				1.43%		1.04%		1.07%
Letters of credit supported by LOC	$	3.3	$	3.0	$	0.3		—
Available	$	1,056.2	$	332.6	$	595.4	$	128.2
December 31, 2015								
Lines of credit:								
Five-year, expiring December 2020	$	1,300.0	$	400.0	$	700.0	$	200.0
Fuel Company five-year, expiring December 2020	$	500.0		—	$	500.0		—
Three-year, expiring December 2018	$	200.0		—	$	200.0		—
Total committed long-term	$	2,000.0	$	400.0	$	1,400.0	$	200.0
Outstanding commercial paper (270 or fewer days)	$	531.4	$	37.4	$	420.2	$	73.8
Weighted average interest rate				1.19%		0.74%		0.77%
Letters of credit supported by LOC	$	3.3	$	3.0	$	0.3		—
Available	$	1,465.4	$	359.6	$	979.6	$	126.2

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to credit agreements in the amounts and for the terms described above. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

Each of the Company and Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2016 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $29 million. At December 31, 2015 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $33 million and money pool investments due from an affiliate of $9 million. On SCE&G's consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense are as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current taxes:						
Federal	$ 36	$ 382	$ 38	$ 50	$ 208	$ 39
State	13	57	(4)	13	32	(6)
Total current taxes	49	439	34	63	240	33
Deferred tax (benefit) expense, net:						
Federal	203	(36)	184	167	(3)	157
State	21	(7)	34	20	(3)	32
Total deferred taxes	224	(43)	218	187	(6)	189
Investment tax credits:						
Amortization of amounts deferred-state	—	(1)	(1)	—	(1)	(1)
Amortization of amounts deferred-federal	(2)	(2)	(3)	(2)	(2)	(3)
Total investment tax credits	(2)	(3)	(4)	(2)	(3)	(4)
Total income tax expense	$ 271	$ 393	$ 248	$ 248	$ 231	$ 218

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Net income	$ 595	$ 746	$ 538	$ 513	$ 466	$ 446
Income tax expense	271	393	248	248	231	218
Noncontrolling interest	—	—	—	13	14	12
Total pre-tax income	$ 866	$ 1,139	$ 786	$ 774	$ 711	$ 676
Income taxes on above at statutory federal income tax rate	$ 303	$ 399	$ 275	$ 271	$ 249	$ 237
Increases (decreases) attributed to:						
State income taxes (less federal income tax effect)	27	38	24	26	24	21
State investment tax credits (less federal income tax effect)	(5)	(6)	(5)	(5)	(6)	(5)
Allowance for equity funds used during construction	(10)	(9)	(11)	(9)	(9)	(10)
Deductible dividends—401(k) Retirement Savings Plan	(10)	(10)	(10)	—	—	—
Amortization of federal investment tax credits	(2)	(2)	(3)	(2)	(2)	(3)
Section 41 tax credits	—	1	(3)	—	1	(3)
Section 45 tax credits	(8)	(9)	(9)	(8)	(9)	(9)
Domestic production activities deduction	(23)	(18)	(7)	(23)	(18)	(7)
Realization of basis differences upon sale of subsidiaries	—	7	—	—	—	—
Other differences, net	(1)	2	(3)	(2)	1	(3)
Total income tax expense	$ 271	$ 393	$ 248	$ 248	$ 231	$ 218

The tax effects of significant temporary differences comprising net deferred tax liability are as follows:

	The Company				Consolidated SCE&G			
Millions of dollars	**2016**		**2015**		**2016**		**2015**	
Deferred tax assets:								
Nondeductible accruals	$	148	$	135	$	53	$	52
Asset retirement obligation, including nuclear decommissioning		213		199		200		187
Financial instruments		22		35		—		2
Unamortized investment tax credits		15		16		15		16
Deferred fuel costs		17		8		17		7
Other		10		5		8		2
Total deferred tax assets		425		398		293		266
Deferred tax liabilities:								
Property, plant and equipment		2,159		1,906		1,856		1,644
Deferred employee benefit plan costs		105		96		93		85
Regulatory asset, asset retirement obligation		143		135		135		127
Regulatory asset, unrecovered plant		45		49		45		49
Demand side management costs		23		23		23		23
Prepayments		32		31		30		29
Other		77		65		50		41
Total deferred tax liabilities		2,584		2,305		2,232		1,998
Net deferred tax liability	$	2,159	$	1,907	$	1,939	$	1,732

The State of North Carolina lowered its corporate income tax rate from 6.9% to 6.0% in 2014, 5.0% in 2015, 4% in 2016 and 3% effective January 1, 2017. In connection with these changes in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The changes in income tax rates did not and are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

The Company files consolidated federal income tax returns which includes Consolidated SCE&G, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company's federal returns through 2004, and the Company's federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2015 as a result of claims discussed below in Changes in Unrecognized Tax Benefits. With few exceptions, the Company, including Consolidated SCE&G, is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes in Unrecognized Tax Benefits

	The Company						Consolidated SCE&G					
Millions of dollars	**2016**		**2015**		**2014**		**2016**		**2015**		**2014**	
Unrecognized tax benefits, January 1	$	49	$	16	$	3	$	49	$	16	$	3
Gross increases—uncertain tax positions in prior period		94		33		—		94		33		—
Gross decreases—uncertain tax positions in prior period		—		(2)		—		—		(2)		—
Gross increases—current period uncertain tax positions		207		2		13		207		2		13
Unrecognized tax benefits, December 31	$	350	$	49	$	16	$	350	$	49	$	16

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models.

The IRS examined the claims in the amended returns, and as the examination progressed without resolution, the Company and Consolidated SCE&G evaluated and recorded adjustments to unrecognized tax benefits; however, none of these changes materially affected the Company's and Consolidated SCE&G's effective tax rate. In October 2016, the examination of the amended tax returns progressed to the IRS Office of Appeals. In addition, the IRS has begun an examination of SCANA's 2013 through 2015 income tax returns.

These income tax deductions and credits are considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, the Company and Consolidated SCE&G have recorded an unrecognized tax benefit of $350 million ($219 million and $236 million for the Company and Consolidated SCE&G, respectively, net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). If recognized, $17 million of the tax benefit would affect the Company's and Consolidated SCE&G's effective tax rate (see discussion below regarding deferral of benefits related to 2015 forward). It is reasonably possible that these unrecognized tax benefits may increase by an additional $292 million within the next 12 months as additional expenditures giving rise to pilot model tax benefits are incurred. It is also reasonably possible that these unrecognized tax benefits may decrease by $49 million within the next 12 months if the claims on the amended returns which are currently in appeals are resolved and that resolution were also applied to the 2013 and 2014 returns. No other material changes in the status of the Company's or Consolidated SCE&G's tax positions have occurred through December 31, 2016.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 income tax returns and the expectation of similar claims to be made in determining 2016's taxable income, the Company and Consolidated SCE&G have recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, and expect that such (net) deferred costs, along with any interest (see below) and other related deferred costs, will be recoverable through customer rates in future years. SCE&G's current customer rates reflect the availability of domestic production activities deductions (see Note 2).

Estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 income tax returns has been deferred as a regulatory asset and is expected to be recoverable through customer rates in future years. See also Note 2. Otherwise, the Company and Consolidated SCE&G recognize interest accrued related to unrecognized tax benefits within interest expense or interest income and recognize tax penalties within other expenses. In 2016, the amount recorded for such interest income is $1.8 million and interest expense is $0.9 million. Such amounts were not significant in 2015 or 2014. No amounts have been recorded for tax penalties for any periods presented.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Derivative instruments are recognized either as assets or liabilities in the statement of financial position and are measured at fair value. Changes in the fair value of derivative instruments are recognized either in earnings, as a component of other comprehensive income (loss) or, for regulated operations, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures, and in some cases risk limits, are established to control the level of market, credit, liquidity and operational and administrative risks. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Risk Management Officer and other senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statements of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and NYMEX futures and options. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the under- or over-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SCANA Energy, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

Interest rate swaps may be used to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which swaps designated as cash flow hedges are used to synthetically convert variable rate debt to fixed rate debt, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

Forward starting swap agreements that are designated as cash flow hedges may be used in anticipation of the issuance of debt. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For SCANA and its nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts related to them are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be amortized to interest expense or may be applied as otherwise directed by the SCPSC.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)		
Hedge designation	**Gas Distribution**	**Gas Marketing**	**Total**
As of December 31, 2016			
Commodity	4,510,000	11,947,000	16,457,000
Energy Management (a)	—	67,447,223	67,447,223
Total (a)	4,510,000	79,394,223	83,904,223
As of December 31, 2015			
Commodity	7,530,000	11,842,500	19,372,500
Energy Management (a)	—	38,857,480	38,857,480
Total (a)	7,530,000	50,699,980	58,229,980

(a) Includes amounts related to basis swap contracts totaling 730,721 MMBTU in 2016 and 1,842,048 MMBTU in 2015.

The aggregate notional amounts of the interest rate swaps were as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	December 31, 2016	December 31, 2015	December 31, 2016	December 31, 2015
Designated as hedging instruments	$ 115.6	$ 120.0	$ 36.4	$ 36.4
Not designated as hedging instruments	1,285.0	1,235.0	1,285.0	1,235.0

The following table shows the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the consolidated balance sheet, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Fair Values of Derivative Instruments

		The Company		Consolidated SCE&G	
Millions of dollars	Balance Sheet Location	Asset	Liability	Asset	Liability
As of December 31, 2016					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 4		$ 1
	Other deferred credits and other liabilities		24		8
Commodity contracts					
	Prepayments	$ 5			
	Other current assets	1			
Total		$ 6	$ 28	—	$ 9
Not designated as hedging instruments					
Interest rate contracts					
	Other deferred debits and other assets	$ 71		$ 71	
	Derivative financial instruments		$ 27		$ 27
	Other deferred credits and other liabilities		3		3
Commodity contracts					
	Other current assets	3			
Energy management contracts					
	Prepayments	6	2		
	Other current assets	2	1		
	Other deferred debits and other assets	2			
	Derivative financial instruments		4		
	Other deferred credits and other liabilities		2		
Total		$ 84	$ 39	$ 71	$ 30
As of December 31, 2015					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 4		$ 1
	Other deferred credits and other liabilities		28		9
Commodity contracts					
	Other current assets		1		
	Derivative financial instruments		4		
Total		—	$ 37	—	$ 10

Not designated as hedging instruments				
Interest rate contracts				
Other current assets	$ 10		$ 10	
Other deferred debits and other assets	5		5	
Derivative financial instruments		$ 33		$ 33
Other deferred credits and other liabilities		22		22
Commodity contracts				
Other current assets	1			
Energy management contracts				
Other current assets	11	2		
Other deferred debits and other assets	3			
Derivative financial instruments		9		
Other deferred credits and other liabilities		3		
Total	$ 30	$ 69	$ 15	$ 55

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

The Company and Consolidated SCE&G:	**Loss Deferred in Regulatory Accounts**	**Loss Reclassified from Deferred Accounts into Income (Effective Portion)**	
Millions of dollars	**(Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2016			
Interest rate contracts	—	Interest expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)

The Company:	**Gain or (Loss) Recognized in OCI, net of tax**	**Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion)**	
Millions of dollars	**(Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2016			
Interest rate contracts	$ (1)	Interest expense	$ (7)
Commodity contracts	5	Gas purchased for resale	(6)
Total	$ 4		$ (13)
Year Ended December 31, 2015			
Interest rate contracts	$ (2)	Interest expense	$ (7)
Commodity contracts	(10)	Gas purchased for resale	(15)
Total	$ (12)		$ (22)
Year Ended December 31, 2014			
Interest rate contracts	$ (6)	Interest expense	$ (7)
Commodity contracts	(8)	Gas purchased for resale	4
Total	$ (14)		$ (3)

As of December 31, 2016, the Company expects that during the next 12 months reclassifications from AOCI to earnings arising from cash flow hedges will include approximately $5.4 million as a decrease to gas cost, assuming natural gas markets remain at their current levels, and approximately $7.2 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2016, all of the Company's commodity cash flow hedges settle by their terms before the end of the second quarter of 2019.

As of December 31, 2016, each of the Company and Consolidated SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.8 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

For the Company and Consolidated SCE&G, ineffectiveness on interest rate hedges designated as cash flow hedges was insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

The Company and Consolidated SCE&G:			**Gain (Loss) Reclassified from Deferred Accounts into Income**		
Millions of dollars	**Loss Deferred in Regulatory Accounts**		**Location**	**Amount**	
Year Ended December 31, 2016					
Interest rate contracts	$	(34)	Interest Expense	$	(2)
Year Ended December 31, 2015					
Interest rate contracts	$	(69)	Other income	$	5
Year Ended December 31, 2014					
Interest rate contracts	$	(352)	Other income	$	64

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2016, the Company and Consolidated SCE&G expect that during the next 12 months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $2.4 million as an increase to interest expense.

Credit Risk Considerations

Certain derivative contracts contain contingent credit features. These features may include (i) material adverse change clauses or payment acceleration clauses that could result in immediate payments or (ii) the posting of letters of credit or termination of the derivative contract before maturity if specific events occur, such as a credit rating downgrade below investment grade or failure to post collateral.

Derivative Contracts with Credit Contingent Features

	The Company				**Consolidated SCE&G**			
Millions of dollars	**December 31, 2016**		**December 31, 2015**		**December 31, 2016**		**December 31, 2015**	
in Net Liability Position								
Aggregate fair value of derivatives in net liability position	$	50.3	$	95.2	$	30.3	$	57.0
Fair value of collateral already posted		29.2		50.4		9.2		13.4
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered		21.1		44.8		21.1		43.6
in Net Asset Position								
Aggregate fair value of derivatives in net asset position	$	62.9	$	7.3	$	62.0	$	7.3
Fair value of collateral already posted		—		—		—		—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered		62.9		7.3		62.0		7.3

In addition, for fixed price supply contracts offered to certain of SCANA Energy's customers, the Company could have called on letters of credit in the amount of $1.5 million related to $9.0 million in commodity derivatives that are in a net asset position at December 31, 2016, compared to letters of credit of $3.0 million related to derivatives of $14.0 million at December 31, 2015, if all the contingent features underlying these instruments had been fully triggered.

Information related to the offsetting derivative assets follows:

Derivative Assets	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2016					
Gross Amounts of Recognized Assets	$ 71	$ 9	$ 10	$ 90	$ 71
Gross Amounts Offset in Statement of Financial Position			(4)	(4)	
Net Amounts Presented in Statement of Financial Position	71	9	6	86	71
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 62	$ 9	$ 6	$ 77	$ 62
Balance sheet location					
Prepayments				$ 9	
Other current assets				5	
Other deferred debits and other assets				72	$ 71
Total				$ 86	$ 71
As of December 31, 2015					
Gross Amounts of Recognized Assets	$ 15	$ 1	$ 15	$ 31	$ 15
Gross Amounts Offset in Statement of Financial Position			(1)	(1)	
Net Amounts Presented in Statement of Financial Position	15	1	14	30	15
Gross Amounts Not Offset - Financial Instruments	(8)			(8)	(8)
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 7	$ 1	$ 14	$ 22	$ 7
Balance sheet location					
Other current assets				$ 22	$ 10
Other deferred debits and other assets				8	5
Total				$ 30	$ 15

Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2016					
Gross Amounts of Recognized Liabilities	$ 58		$ 9	$ 67	$ 39
Gross Amounts Offset in Statement of Financial Position			(3)	(3)	
Net Amounts Presented in Statement of Financial Position	58	—	6	64	39
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Posted	(29)			(29)	(9)
Net Amount	$ 20	—	$ 6	$ 26	$ 21
Balance sheet location					
Derivative financial instruments				$ 35	$ 28
Other deferred credits and other liabilities				29	11
Total				$ 64	$ 39

As of December 31, 2015					
Gross Amounts of Recognized Liabilities	$ 87	$ 5	$ 15	$ 107	$ 65
Gross Amounts Offset in Statement of Financial Position			(1)	(1)	
Net Amounts Presented in Statement of Financial Position	87	5	14	106	65
Gross Amounts Not Offset - Financial Instruments	(8)			(8)	(8)
Gross Amounts Not Offset - Cash Collateral Posted	(36)	(5)	(9)	(50)	(13)
Net Amount	$ 43	$ —	$ 5	$ 48	$ 44
Balance sheet location					
Other current assets				$ 3	
Derivative financial instruments				50	$ 34
Other deferred credits and other liabilities				53	31
Total				$ 106	$ 65

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Available for sale securities are valued using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2016			As of December 31, 2015		
	The Company		Consolidated SCE&G	The Company		Consolidated SCE&G
Millions of dollars	**Level 1**	**Level 2**	**Level 2**	**Level 1**	**Level 2**	**Level 2**
Assets:						
Available for sale securities	$ 14	—	—	$ 11	—	—
Held to maturity securities	—	$ 7	—	—	—	—
Interest rate contracts	—	71	$ 71	—	$ 15	$ 15
Commodity contracts	8	1	—	1	—	—
Energy management contracts	6	4	—	—	14	—
Liabilities:						
Interest rate contracts	—	58	39	—	87	65
Commodity contracts	—	—	—	1	4	—
Energy management contracts	2	10	—	4	12	—

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2016 and December 31, 2015 were as follows:

	As of December 31, 2016		As of December 31, 2015	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
The Company	$ 6,489.8	$ 7,183.3	$ 5,997.6	$ 6,445.7
Consolidated SCE&G	5,166.0	5,752.3	4,769.0	5,129.1

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. SCE&G participates in SCANA's pension plan. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. SCE&G participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	The Company				Consolidated SCE&G			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2016	2015	2016	2015	2016	2015	2016	2015
Benefit obligation, January 1	$ 855.4	$ 919.5	$ 253.6	$ 268.2	$ 724.0	$ 773.7	$ 191.7	$ 204.1
Service cost	20.7	24.1	4.4	5.3	16.9	19.3	3.6	4.4
Interest cost	39.4	38.2	12.1	11.4	33.4	32.2	9.9	9.4
Plan participants' contributions	—	—	1.7	2.4	—	—	1.3	1.9
Actuarial (gain) loss	45.0	(62.4)	14.0	(21.2)	41.8	(47.0)	11.5	(15.7)
Benefits paid	(56.2)	(64.0)	(11.1)	(12.5)	(47.7)	(54.2)	(9.1)	(10.3)
Amounts Funded to parent	n/a	n/a	n/a	n/a	—	—	(1.7)	(2.1)
Benefit obligation, December 31	$ 904.3	$ 855.4	$ 274.7	$ 253.6	$ 768.4	$ 724.0	$ 207.2	$ 191.7

In 2015, based on an evaluation of the mortality experience of the pension plan, a custom mortality table was adopted for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations for the Company of approximately $21.5 million and $2.4 million, respectively. This change resulted in an actuarial gain for pension and other postretirement benefit obligations for Consolidated SCE&G of approximately $18.2 million and $2.0 million, respectively.

The accumulated benefit obligation for pension benefits for the Company was $874.3 million at the end of 2016 and $829.3 million at the end of 2015. The accumulated benefit obligation for pension benefits for Consolidated SCE&G was $742.9 million at the end of 2016 and $702.0 million at the end of 2015.The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	2016	2015
Annual discount rate used to determine benefit obligation	4.22%	4.68%	4.30%	4.78%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 6.6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate for the Company would increase the postretirement benefit obligation by $0.8 million at December 31, 2016 and by $0.8 million at December 31, 2015. A one percent decrease in the assumed health care cost trend rate for the Company would decrease the postretirement benefit obligation by $0.7 million at December 31, 2016 and by $0.7 million at December 31, 2015. A one percent increase in the assumed health care cost trend rate for Consolidated SCE&G would increase the postretirement benefit obligation by $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015. A one percent decrease in the assumed health care cost trend rate for Consolidated SCE&G would decrease the postretirement benefit obligation by $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015.

Funded Status

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Fair value of plan assets	$ 793.6	$ 781.7	—	—	$ 732.9	$ 720.1	—	—
Benefit obligation	904.3	855.4	$ 274.7	$ 253.6	768.4	724.0	$ 207.2	$ 191.7
Funded status	$ (110.7)	$ (73.7)	$ (274.7)	$ (253.6)	$ (35.5)	$ (3.9)	$ (207.2)	$ (191.7)

Amounts recognized on the consolidated balance sheets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Current liability	—	—	$ (12.6)	$ (11.9)	—	—	$ (10.4)	$ (9.8)
Noncurrent liability	$ (110.7)	$ (73.7)	(262.1)	(241.7)	$ (35.5)	$ (3.9)	(196.8)	(181.9)

Amounts recognized in accumulated other comprehensive loss were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Net actuarial loss	$ 10.4	$ 10.4	$ 2.5	$ 1.7	$ 1.9	$ 2.0	$ 1.0	$ 0.7
Prior service cost	0.1	0.2	—	—	—	—	—	—
Total	$ 10.5	$ 10.6	$ 2.5	$ 1.7	$ 1.9	$ 2.0	$ 1.0	$ 0.7

Amounts recognized in regulatory assets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Net actuarial loss	$ 236.1	$ 219.4	$ 34.7	$ 24.0	$ 208.8	$ 193.7	$ 29.3	$ 20.4
Prior service cost	2.5	5.9	—	0.3	2.2	5.2	—	0.2
Total	$ 238.6	$ 225.3	$ 34.7	$ 24.3	$ 211.0	$ 198.9	$ 29.3	$ 20.6

In connection with the joint ownership of Summer Station, pension costs attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $23.4 million and $20.3 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $15.8 million and $13.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

	The Company		Consolidated SCE&G	
	Pension Benefits		Pension Benefits	
Millions of dollars	**2016**	**2015**	**2016**	**2015**
Fair value of plan assets, January 1	$ 781.7	$ 861.8	$ 720.1	$ 783.6
Actual return (loss) on plan assets	68.1	(16.1)	60.5	(9.3)
Benefits paid	(56.2)	(64.0)	(47.7)	(54.2)
Fair value of plan assets, December 31	$ 793.6	$ 781.7	$ 732.9	$ 720.1

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. SCANA uses a dynamic investment strategy for the management of the pension plan assets. This strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2016 and 2015 and the target allocation for 2017 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2017**	**2016**	**2015**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	32%
Hedge Funds	9%	11%	11%

For 2017, the expected long-term rate of return on assets will be 7.25%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan’s historical cumulative actual returns over several periods, considers the expected active and passive returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2016 and 2015, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	The Company 2016	The Company 2015	Consolidated SCE&G 2016	Consolidated SCE&G 2015
Investments with fair value measure at Level 2:				
Mutual funds	$ 125	$ 125	$ 115	$ 115
Short-term investment vehicles	16	14	15	12
US Treasury securities	18	22	17	20
Corporate debt securities	82	78	76	72
Municipals	14	14	13	13
Total assets in the fair value hierarchy	255	253	236	232
Investments at net asset value:				
Common collective trust	453	413	418	381
Joint venture interests	86	83	79	77
Limited partnership	—	33	—	30
Total investments at fair value	$ 794	$ 782	$ 733	$ 720

For all periods presented, assets with fair value measurements classified as Level 1 were insignificant, and there were no assets with fair value measurements classified as Level 3. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2016 or 2015. In addition, in 2015 the fair value of pension plan assets totaling $413 million for the Company and $381 million for Consolidated SCE&G were previously depicted as mutual funds but have been reclassified as Common collective trust for the current presentation.

Mutual funds held by the plan are open-ended mutual funds registered with the SEC. The price of the mutual funds' shares is based on its NAV, which is determined by dividing the total value of portfolio investments, less any liabilities, by the total number of shares outstanding. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. US Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Common collective trust assets and limited partnerships are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds' net assets at fair value by the units outstanding at each valuation date. Joint venture interests assets are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and not traded on a daily basis. The valuation of such multi-strategy hedge fund of funds is estimated based on the NAV of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may influence their fair value.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	The Company Pension Benefits	The Company Other Postretirement Benefits	Consolidated SCE&G Pension Benefits	Consolidated SCE&G Other Postretirement Benefits
2017	$ 63.1	$ 12.9	$ 63.1	$ 10.6
2018	65.1	13.7	65.1	11.2
2019	64.5	14.5	64.5	11.9
2020	64.7	15.3	64.7	12.5
2021	67.1	15.9	67.1	13.1
2022-2026	324.4	86.0	324.4	70.5

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals at the end of 2023, no significant contributions to the pension plan are expected to be made for the foreseeable future based on current market conditions and assumptions.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

The Company	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Service cost	$ 20.7	$ 24.1	$ 20.0	$ 4.4	$ 5.3	$ 4.6
Interest cost	39.4	38.2	40.4	12.1	11.4	12.0
Expected return on assets	(55.9)	(62.0)	(66.7)	n/a	n/a	n/a
Prior service cost amortization	3.9	4.1	4.1	0.3	0.4	0.3
Amortization of actuarial losses	14.8	13.6	4.8	0.5	2.1	—
Net periodic benefit cost	$ 22.9	$ 18.0	$ 2.6	$ 17.3	$ 19.2	$ 16.9

Consolidated SCE&G	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Service cost	$ 16.9	$ 19.3	$ 16.0	$ 3.6	$ 4.4	$ 3.6
Interest cost	33.4	32.2	34.1	9.9	9.4	9.4
Expected return on assets	(47.4)	(52.2)	(56.3)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.4	3.5	0.3	0.3	0.3
Amortization of actuarial losses	12.5	11.4	4.0	0.4	1.7	—
Net periodic benefit cost	$ 18.8	$ 14.1	$ 1.3	$ 14.2	$ 15.8	$ 13.3

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

The Company	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 0.6	$ 2.7	$ 3.1	$ 0.8	$ (1.2)	$ 1.3
Amortization of actuarial losses	(0.6)	(0.4)	(0.2)	—	(0.1)	—
Amortization of prior service cost	(0.1)	(0.1)	(0.2)	—	(0.1)	—
Total recognized in OCI	$ (0.1)	$ 2.2	$ 2.7	$ 0.8	$ (1.4)	$ 1.3

Consolidated SCE&G	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	—	$ 0.2	$ 0.2	$ 0.3	$ (0.3)	$ 0.4
Amortization of actuarial losses	$ (0.1)	(0.1)	(0.1)	—	—	—
Amortization of prior service cost	—	(0.1)	(0.1)	—	—	—
Total recognized in OCI	$ (0.1)	$ —	$ —	$ 0.3	$ (0.3)	$ 0.4

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

The Company	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 29.4	$ 9.2	$ 101.3	$ 11.1	$ (18.0)	$ 19.4
Amortization of actuarial losses	(12.7)	(11.9)	(4.0)	(0.4)	(1.8)	—
Amortization of prior service cost	(3.4)	(3.7)	(3.2)	(0.3)	(0.3)	(0.3)
Total recognized in regulatory assets	$ 13.3	$ (6.4)	$ 94.1	$ 10.4	$ (20.1)	$ 19.1

Consolidated SCE&G	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 26.3	$ 12.2	$ 87.7	$ 9.2	$ (14.0)	$ 15.8
Amortization of actuarial losses	(11.2)	(10.4)	(3.5)	(0.3)	(1.5)	—
Amortization of prior service cost	(3.0)	(3.1)	(2.8)	(0.2)	(0.3)	(0.2)
Total recognized in regulatory assets	$ 12.1	$ (1.3)	$ 81.4	$ 8.7	$ (15.8)	$ 15.6

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			**Other Postretirement Benefits**		
	2016	**2015**	**2014**	**2016**	**2015**	**2014**
Discount rate	4.68%	4.20%	5.03%	4.78%	4.30%	5.19%
Expected return on plan assets	7.50%	7.50%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%	3.00%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.00%	7.40%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2021	2020	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 are as follows for the Company. For Consolidated SCE&G such amounts are insignificant:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 0.6	$ 0.1
Prior service cost	0.1	—
Total	$ 0.7	$ 0.1

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2017 are as follows:

	The Company		**Consolidated SCE&G**	
Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 13.6	$ 1.2	$ 12.0	$ 1.0
Prior service cost	1.4	—	1.3	—
Total	$ 15.0	$ 1.2	$ 13.3	$ 1.0

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCANA sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. SCE&G participates in this plan. Contributions are matched 100% up to 6% of an employee’s eligible earnings. Such matching contributions made by the Company totaled $27.5 million in 2016, $26.2 million in 2015 and $25.8 million in 2014. These matching contributions included those made by Consolidated SCE&G, which totaled $22.9 million in 2016, $21.8 million in 2015 and $20.7 million in 2014. Employee deferrals, matching contributions, and earnings on all contributions are fully vested and nonforfeitable at all times.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2014-2016 performance cycle provides for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 and 2016-2018 awards are based on performance over a single three-year cycle. In the performance cycle for the 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash, and 80% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For each of the 2015-2017 and 2016-2018 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. At the Company's discretion, awards under the 2014-2016 performance cycle were paid in cash in February 2017 totaling $28.0 million for the Company, of which $20.2 million was attributable to Consolidated SCE&G (including amounts allocated from SCANA Services). Cash-settled liabilities related to earlier performance cycles totaled approximately $18.4 million in 2016, $20.8 million in 2015 and $11.8 million in 2014 for the Company and approximately $13.2 million in 2016, $6.3 million in 2015 and $1.9 million in 2014 for Consolidated SCE&G.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $25.6 million in 2016, $18.0 million in 2015 and $20.3 million in 2014 for the Company, of which approximately $17.3 million in 2016, $12.2 million in 2015 and $12.6 million in 2014 for Consolidated SCE&G (including amounts allocated from SCANA Services). Such fair value adjustments also resulted in capitalized compensation costs of $3.3 million in 2016, $2.3 million in 2015 and $3.1 million in 2014 for the Company and $3.1 million in 2016, $0.6 million in 2015 and $0.6 million in 2014 for Consolidated SCE&G. At December 31, 2016, unrecognized compensation cost, which is expected to be recognized over a weighted-average period of 18 months, was $23.4 million for the Company and $17.2 million for Consolidated SCE&G.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at SCE&G's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin and up to $2.33 billion resulting from an event of a non-nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of total coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $45.8 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Unit 1 for property damage and outage costs up to $415 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $1.8 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on the Company's and Consolidated SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium in 2008 for the design and construction of the New Units. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Estimated operating costs, including the depreciation of the utility plant costs, are then to be recovered through rates beginning when the construction of each New Unit is completed and placed into service. The BLRA also provides that, in the event of abandonment prior to plant completion, construction work in progress costs incurred, including AFC, and a return on those costs may be recoverable through rates, so long as SCE&G demonstrates by a preponderance of the evidence that its decision to abandon the New Unit(s) was prudent. As of December 31, 2016, SCE&G's investment in the New Units, including related transmission, totaled $4.5 billion, for which the financing costs on $3.8 billion have been reflected in rates under the BLRA. See Note 2 for a description of rate changes which have occurred under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. The Consortium has experienced delays throughout much of the project to date, and forecasted work crew efficiency and productivity metrics have not been met. In response, in November 2012, and again in September 2015 and November 2016 (see discussion below), the SCPSC approved SCE&G's requested updates to the milestone schedule, revised contractual substantial completion dates, and increases in capital and other costs. Some of these increased costs were the result of the schedule delays and were the subject of dispute.

October 2015 Amendment and WEC's Engagement of Fluor

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor as a subcontracted construction manager.

Among other things, the October 2015 Amendment provided SCE&G and Santee Cooper an irrevocable option to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G's 55% portion being approximately $3.345 billion). This total amount to be paid would be reduced by amounts paid since June 30, 2015. SCE&G, on behalf of itself and as agent for Santee Cooper, executed the fixed price option, subject to SCPSC approval, on July 1, 2016.

The October 2015 Amendment:

(i) resolved by settlement and release most outstanding disputes between SCE&G and the Consortium,

(ii) revised the contractual guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), resulting in escalating liquidated damages that are capped at an aggregate of $338 million per New Unit (SCE&G's 55% portion being approximately $186 million per New Unit),

(iv) provided for payment to the Consortium of a completion bonus of $150 million per New Unit (SCE&G's 55% portion being approximately $83 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provided for development of a revised construction milestone payment schedule,

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project,

(vii) provided for an explicit definition of Change in Law designed to reduce the likelihood of certain future commercial disputes, with the Consortium also acknowledging and agreeing that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19, and

(viii) eliminated the requirement or ability of any party to bring suit regarding disputes before substantial completion of the project.

As part of its responsibility as a subcontracted construction manager, Fluor has reviewed and assisted in the development of an updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within the SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits (see below). However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to achieve forecasted productivity and work force efficiency levels.

November 2016 SCPSC Order

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. See also Note 2.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. SCE&G cannot determine when the SCPSC will issue its order in this matter or if that order will be appealed.

Construction Milestone Payment Schedule and Related DRB Activity

The October 2015 Amendment established a DRB process for resolving certain commercial claims and disputes. The DRB is comprised of three members chosen by the parties, and amounts in dispute of less than $5 million will be resolved by the DRB without recourse. Amounts in dispute greater than $5 million will be resolved by the DRB for the remainder of the construction of the New Units, with a reserved right to further arbitrate or to litigate such issues at the conclusion of construction.

On December 2, 2016 the DRB issued an order establishing a construction milestone payment schedule (see (v) in October 2015 Amendment above) on which SCE&G and WEC had been unable to agree subsequent to the October 2015 Amendment. The dispute related only to the timing of payments; the total amount to be paid was not in dispute. The DRB order provides that certain subcontractor and other supplier-related costs incurred by the Consortium will be reimbursed by the owners regardless of payment-milestone completion, but that other payments will be made only upon documented achievement of the agreed-upon payment-milestones. Such subcontractor and other supplier-related costs comprised approximately $873 million of the $3.345 billion of fixed option payments that were the subject of the DRB order.

Payment and Performance Obligations and Certain Related Uncertainties

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba, WEC's parent company, reaffirmed its guaranty of WEC's payment obligations. Additionally, the EPC Contract provides the owners the right, exercisable upon certain conditions, to obtain payment and performance bonds from WEC equal to 15% of the highest projected three months billings during the applicable year, and their aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bonds.

In late 2015, Toshiba's credit ratings declined to below investment grade following disclosures regarding its operating and financial performance and near-term liquidity. As a result, pursuant to the above-described terms of the EPC Contract, SCE&G has obtained standby letters of credit in lieu of payment and performance bonds from WEC totaling $45 million (or approximately $25 million for SCE&G's 55% share). These standby letters of credit expire annually in February, and they automatically renew for successive one-year periods until their final expiration date of August 31, 2020, unless the issuer provides a minimum 60-day notice that it will not renew. If the issuer provides notice that it will not renew, SCE&G may draw upon the standby letter of credit prior to its expiration. In the event that WEC would be unable to meet its payment and performance obligations under the EPC Contract, it is anticipated this funding would provide a source of liquidity to assist in an orderly transition. In addition, the EPC Contract provides that upon the request of SCE&G, and at owners' cost, the Consortium must escrow certain intellectual property and software for the owners' benefit to assist in completion of the New Units. An escrow arrangement has been established, and certain intellectual property and software have been deposited. Additional deposits are anticipated.

In December 2016 through February 2017, Toshiba and WEC announced further deterioration in their financial position and liquidity related to write-downs arising from WEC's acquisition of Stone and Webster from CB&I (discussed above). The announcements noted that WEC and Toshiba have determined that significant losses will be incurred under the EPC Contract for the New Units and under a similar engineering, procurement and construction agreement for other units currently being constructed in the United States. This determination has impacted their allocation of the CB&I purchase price, resulting in recognition of a large amount of goodwill which has in turn been determined to be impaired. Preliminary recognition of this impairment loss (in excess of $6 billion) has left Toshiba with negative shareholders' equity and threatened its liquidity. In January 2017, Toshiba's credit ratings were further reduced. In response, Toshiba has indicated its interest in monetizing portions of its business as it attempts to restructure and restore its financial position. Toshiba has also indicated that it will withdraw from the nuclear construction business prospectively and that it will significantly alter its risk management oversight of its nuclear power business. WEC has told the Company that it and Toshiba are committed to completing the New Units. Toshiba has acknowledged its parental guaranty to the project, but it has informed the Company that no specific commitment regarding completion of the New Units has been agreed to by it so far.

Toshiba also announced that it had requested (and successfully received) a one-month extension of the deadline for submitting its securities report to Japanese securities regulators for the quarter ended December 31, 2016 to allow an internal investigation into the adequacy of internal controls relating to the purchase price allocation process for WEC's acquisition of Stone & Webster and concerns that senior management at WEC may have exerted inappropriate pressure in order to advance the purchase price allocation process. As part of the announcement, it was stated that Toshiba's audit committee was concerned that an invalidation of internal controls (or even the possibility thereof) might affect Toshiba's quarterly financial statements, and that two law firms had been separately retained by the audit committee and WEC to assist with this investigation.

Although progress on the project was seen in December 2016 and January 2017, including the placement of the first of Unit 2's two steam generators, significant risks and uncertainties remain concerning WEC's ability to improve work force efficiency and productivity performance and to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project. In particular, there can be no assurance that their creditors will continue to provide support or that other sources of liquidity will emerge or continue to be available. In the event that WEC were to fail to complete the project in breach of its obligations under the EPC Contract, its payment obligations for damages would increase substantially above the amount of the liquidated damages described above, but would still be subject to limitations.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under possible arrangements with other contractors or, were it determined to be prudent, halting the project and leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA.

Also, in response to these developments and in light of the DRB-established construction milestone payment schedule, in February 2017, SCE&G initiated its solicitation for increased levels of standby letters of credit in lieu of payment and performance bonds referred to above. However, it is uncertain whether such additional levels of standby letters of credit will be available at reasonable cost or whether any letters of credit will continue to be renewed by their issuers.

Finally, additional claims by the Consortium or SCE&G involving the project schedule, budget and performance may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues, and SCE&G expects to resolve disputes through those means. SCE&G expects to seek recovery through rates of any project costs that arise through such dispute resolution processes, as well as other project costs identified from time to time; however, any such request would be subject to the provisions of the November 2016 SCPSC order discussed above. There can be no assurance that recovery would be granted.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction is subject to customary closing conditions, including receipt of necessary regulatory approvals. This transaction will not affect the payment obligations between the parties during construction of the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. SCE&G's current projected cost for the additional 5% interest being acquired from Santee Cooper is approximately $850 million.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the IRC to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on current tax law and the contractual guaranteed substantial completion dates (and the recently revised forecasted dates of completion) provided above, both New Units would be operational and would qualify for the nuclear production tax credits; however, any further delays in the schedule or changes in tax law could adversely impact these conclusions. See also the Payment and Performance Obligations and Certain Related Uncertainties discussion above. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan remains under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, the Company and Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company and Consolidated SCE&G expect to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives each state from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. The Company and Consolidated SCE&G expect any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual SO_2 emissions and annual and ozone season NO_X emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for SO_2 and NO_X and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. The State of South Carolina has chosen to remain in the CSAPR program, even though recent court rulings exempted the state. This allows the state to remain compliant with regional haze standards. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any costs incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The MATS rule has been the subject of ongoing litigation even while it remains in effect. Rulings on this litigation are not expected to have an impact on SCE&G or GENCO due to plant retirements, conversions, and enhancements. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule became effective on January

4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. The Company and Consolidated SCE&G expect that wastewater treatment technology retrofits will be required at Williams and Wateree Stations. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications to ensure compliance with this rule. Any costs incurred to comply with this rule are expected to be recoverable through rates.

The EPA's final rule for CCR became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. The Company and Consolidated SCE&G do not expect the incremental compliance costs associated with this rule to be significant and expect to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2016, the federal government has not accepted any spent fuel from Unit 1, and it remains unclear when the repository may become available. SCE&G has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2018 and will cost an additional $10.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2016, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $25.7 million and are included in regulatory assets.

Claims and Litigation

The Company and Consolidated SCE&G are subject to various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on the Company's and Consolidated SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company and Consolidated SCE&G are obligated under various operating leases for land, office space, furniture, vehicles, equipment, rail cars, a purchase power agreement, and for the Company, airplanes. Leases expire at various dates through 2057.

Millions of dollars	Rent Expense 2016	2015	2014
The Company	$ 10.2	$ 11.1	$ 12.3
Consolidated SCE&G	12.2	12.3	12.1

Millions of dollars	Future Minimum Rental Payments 2017	2018	2019	2020	2021	Thereafter
The Company	$ 31	$ 29	$ 28	$ 3	$ 3	$ 23
Consolidated SCE&G	25	23	22	1	—	17

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2016, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.7 billion.

Asset Retirement Obligations

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2016, SCE&G has recorded AROs of approximately $199 million for nuclear plant decommissioning (see Note 1). In addition, the Company has recorded AROs of approximately $359 million, including $323 million for Consolidated SCE&G, for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	2016	2015	2016	2015
Beginning balance	$ 520	$ 563	$ 488	$ 536
Liabilities incurred	—	—	—	—
Liabilities settled	(11)	(16)	(11)	(16)
Accretion expense	23	25	22	23
Revisions in estimated cash flows	26	(52)	23	(55)
Ending balance	$ 558	$ 520	$ 522	$ 488

Revisions in estimated cash flows in 2016 primarily related to changes in projected costs, based on a nuclear decommissioning cost study. Such revisions in 2015 related to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study.

11. AFFILIATED TRANSACTIONS

The Company:

The Company received cash distributions from equity-method investees of $3.7 million in 2016, $4.0 million in 2015 and $7.8 million in 2014. The Company made investments in equity-method investees of $5.5 million in 2016, $4.1 million in 2015 and $5.7 million in 2014.

The Company and Consolidated SCE&G:

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. Consolidated SCE&G's total purchases from this affiliate were $161.8 million in 2016, $233.2 million in 2015 and $260.3 million in 2014. Consolidated SCE&G's total sales to this affiliate were $160.8 million in 2016, $232.0 million in 2015 and $259.0 million in 2014. The net of the total purchases and total sales are recorded in Other expenses on the consolidated statements of income (for the Company) and of comprehensive income (for Consolidated SCE&G). Consolidated SCE&G's payable to this affiliate was $16.1 million at December 31, 2016 and $12.9 million at December 31, 2015. Consolidated SCE&G's receivable from this affiliate was $16.0 million at December 31, 2016 and $12.8 million at December 31, 2015.

Consolidated SCE&G:

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $111.5 million in 2016, $128.5 million in 2015 and $195.7 million in 2014. SCE&G's payables to SCANA Energy for such purchases were $8.8 million and $7.5 million as of December 31, 2016 and 2015, respectively.

SCANA Services, on behalf of itself and its parent company, provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services, including amounts capitalized, totaled $337.7 million in 2016, $300.0 million in 2015 and $292.2 million in 2014. Amounts expensed are recorded in Other operation and maintenance - nonconsolidated affiliate and Other expenses on the consolidated statements of comprehensive income. Consolidated SCE&G's payables to SCANA Services for these services were $63.5 million and $57.0 million at December 31, 2016 and 2015, respectively.

Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in 2015 and $30.0 million in 2014.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs is described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein. Intersegment sales and transfers of electricity and gas are recorded based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively. Gas Marketing is comprised of the marketing operations of SCANA Energy, which markets natural gas to retail customers in Georgia and to industrial and large commercial customers and municipalities in the Southeast.

All Other includes the parent company, a services company and other nonreportable segments that were insignificant for all periods presented. In addition, All Other includes gains from the sales of CGT and SCI (see Note 1) and their operating results and assets prior to their sale in the first quarter of 2015. CGT and SCI were nonreportable segments during all periods presented. External revenue and intersegment revenue for All Other related to CGT and SCI were not significant during any period presented.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. Gas Marketing operates in a deregulated environment.

Management uses operating income to measure segment profitability for its regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, no allocation is made to segments for interest charges, income tax expense or assets other than utility plant. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Intersegment revenue for SCE&G was not significant. Interest income is not reported by segment and is not material. Deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the amounts that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs, and totals not allocated to other segments. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Reportable segments have changed from what was reported as of December 31, 2015 to combine the former Retail Gas Marketing and Energy Marketing segments into a single Gas Marketing segment. This change in reportable segments occurred due to changes in the structure of the Company's internal organization which included the integration of strategic planning and reporting for these business units and the related integration of the chief operating decision maker's assessment of performance and resource allocation. Corresponding amounts in prior periods have been revised to conform to the current presentation.

Disclosure of Reportable Segments

The Company:

Millions of dollars	Electric Operations	Gas Distribution	Gas Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2016						
External Revenue	$ 2,614	$ 788	$ 825	—	—	$ 4,227
Intersegment Revenue	5	2	111	$ 414	$ (532)	—
Operating Income	957	148	n/a	—	48	1,153
Interest Expense	17	25	1	—	299	342
Depreciation and Amortization	287	82	2	16	(16)	371
Income Tax Expense	8	32	19	—	212	271
Net Income (Loss)	n/a	n/a	30	(18)	583	595
Segment Assets	11,929	2,892	230	1,124	2,532	18,707
Expenditures for Assets	1,275	276	2	11	15	1,579
Deferred Tax Assets	9	32	11	—	(52)	—

2015						
External Revenue	$ 2,551	$ 810	$ 1,018	$ 5	$ (4)	$ 4,380
Intersegment Revenue	6	2	128	413	(549)	—
Operating Income	876	152	n/a	236	44	1,308
Interest Expense	17	23	1	1	276	318
Depreciation and Amortization	277	77	2	16	(14)	358
Income Tax Expense	9	32	18	1	333	393
Net Income	n/a	n/a	28	185	533	746
Segment Assets	10,883	2,606	201	998	2,458	17,146
Expenditures for Assets	1,087	203	2	15	(154)	1,153
Deferred Tax Assets	5	29	15	—	(49)	—
2014						
External Revenue	$ 2,622	$ 1,012	$ 1,301	$ 37	$ (21)	$ 4,951
Intersegment Revenue	7	2	196	437	(642)	—
Operating Income	768	159	n/a	27	53	1,007
Interest Expense	19	22	1	5	265	312
Depreciation and Amortization	300	72	2	24	(14)	384
Income Tax Expense	7	33	19	12	177	248
Net Income (Loss)	n/a	n/a	31	(6)	513	538
Segment Assets	10,182	2,487	290	1,474	2,385	16,818
Expenditures for Assets	936	200	2	52	(98)	1,092
Deferred Tax Assets	11	29	20	15	(75)	—

Consolidated SCE&G:

Millions of dollars	**Electric Operations**	**Gas Distribution**	**Adjustments/ Eliminations**	**Consolidated Total**
2016				
External Revenue	$ 2,619	$ 367	—	$ 2,986
Operating Income	957	56	—	1,013
Interest Expense	17	—	$ 253	270
Depreciation and Amortization	287	28	(13)	302
Segment Assets	11,929	825	3,337	16,091
Expenditures for Assets	1,275	78	46	1,399
Deferred Tax Assets	9	n/a	(9)	—
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	876	58	—	934
Interest Expense	17	—	$ 231	248
Depreciation and Amortization	277	28	(11)	294
Segment Assets	10,883	757	3,125	14,765
Expenditures for Assets	1,087	57	(136)	1,008
Deferred Tax Assets	5	n/a	(5)	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	768	62	—	830
Interest Expense	19	—	$ 209	228
Depreciation and Amortization	300	27	(12)	315
Segment Assets	10,182	721	3,175	14,078
Expenditures for Assets	936	55	(57)	934
Deferred Tax Assets	11	n/a	(11)	—

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The Company

Millions of dollars, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2016					
Total operating revenues	$ 1,172	$ 905	$ 1,093	$ 1,057	$ 4,227
Operating income	331	221	348	253	1,153
Net income	176	105	189	125	595
Earnings per share	1.23	.74	1.32	.87	4.16
2015					
Total operating revenues	$ 1,389	$ 967	$ 1,068	$ 956	$ 4,380
Operating income	586	216	292	214	1,308
Net income	400	99	149	98	746
Earnings per share	2.80	.69	1.04	.69	5.22

Consolidated SCE&G

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2016					
Total operating revenues	$ 717	$ 692	$ 882	$ 695	$ 2,986
Operating income	236	222	359	196	1,013
Net Income	116	113	204	93	526
Earnings Available to Common Shareholder	113	110	201	89	513
2015					
Total operating revenues	$ 772	$ 709	$ 806	$ 643	$ 2,930
Operating income	237	218	307	172	934
Net Income	126	111	167	76	480
Earnings Available to Common Shareholder	122	107	164	73	466

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2016, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCANA’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2016, SCANA's disclosure controls and procedures were effective.

Management’s Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2016, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCANA's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2016. There has been no change in SCANA’s internal controls over financial reporting during the quarter ended December 31, 2016 that has materially affected or is reasonably likely to materially affect SCANA’s internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA’s internal control system was designed by or under the supervision of SCANA’s management, including its CEO and CFO, to provide reasonable assurance to SCANA’s management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA’s management assessed the effectiveness of SCANA’s internal control over financial reporting as of December 31, 2016. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA’s management believes that, as of December 31, 2016, internal control over financial reporting is effective based on those criteria.

SCANA’s independent registered public accounting firm has issued an attestation report on SCANA’s internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2016, of the Company and our report dated February 24, 2017, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2016, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2016, SCE&G's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2016, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCE&G's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2016. There has been no change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2016 that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G's internal control system was designed by or under the supervision of SCE&G's management, including its CEO and CFO, to provide reasonable assurance to SCE&G's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G's management assessed the effectiveness of SCE&G's internal control over financial reporting as of December 31, 2016. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).* Based on this assessment, SCE&G's management believes that, as of December 31, 2016, internal control over financial reporting is effective based on those criteria.

ITEM 9B. OTHER INFORMATION

SCANA:

The following information is included herein in lieu of filing it in Item 1.01 of Form 8-K:

On February 22, 2017, consistent with its past practice, SCANA entered into an indemnification agreement with Randal M. Senn in connection with his promotion in 2016.

The indemnification agreement generally provides that SCANA will indemnify the covered person for claims arising in such person's capacity as a director, officer, employee or other agent of SCANA or its subsidiaries, provided that, among other things, such person acted in good faith and with a view to the best interests of SCANA and, with respect to any criminal proceeding, had no reasonable grounds for believing that person's conduct was unlawful. The indemnification agreement also provides for payment for or reimbursement of reasonable expenses incurred by an indemnitee who is a party to a proceeding in advance of final disposition of the proceeding under certain circumstances.

The above description of the indemnification agreement is qualified in its entirety by reference to the form of indemnification agreement that was filed as Exhibit 10.01 to SCANA's Quarterly Report on Form 10-Q for the period ended June 30, 2012 and that is incorporated herein by reference.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 23. The other information required by Item 10 is incorporated herein by reference to the captions "INFORMATION ABOUT EXPERIENCE AND QUALIFICATION OF DIRECTORS AND NOMINEES," "NOMINEES FOR DIRECTOR," "CONTINUING DIRECTORS," "BOARD MEETINGS-COMMITTEES OF THE BOARD", "GOVERNANCE INFORMATION-SCANA's Code of Conduct & Ethics" and "OTHER INFORMATION-Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by Item 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table," "2016 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2016 Fiscal Year-End," "2016 Option Exercises and Stock Vested," "Pension Benefits," "2016 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: Information required by Item 12 is incorporated herein by reference to the caption "SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT" in SCANA's definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

Equity securities issuable under SCANA's compensation plans at December 31, 2016 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)		(b)	(c)
Equity compensation plans approved by security holders:				
2015 Long-Term Equity Compensation Plan	306,428	(1)	n/a	4,963,572
Prior Long-Term Equity Compensation Plan	296,732	(2)	n/a	—
Non-Employee Director Compensation Plan	n/a		n/a	179,248
Equity compensation plans not approved by security holders	n/a		n/a	n/a
Total	603,160		n/a	5,142,820

(1) Represents unearned non-vested performance share awards from the 2015-2017 and 2016-2018 performance periods assuming a target level payout.
(2) Represents performance shares related to vested grants from the 2014-2016 performance period which were settled in cash rather than shares in February 2017.

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: The information required by Item 13 is incorporated herein by reference to the captions “RELATED PARTY TRANSACTIONS” and “GOVERNANCE INFORMATION - Director Independence” in SCANA’s definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA: The information required by Item 14 is incorporated herein by reference to “PROPOSAL 4-APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM” in SCANA’s definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities and Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm’s Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to SCE&G and its consolidated affiliates for the fiscal years ended December 31, 2016 and 2015 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2016	2015
Audit Fees (1)	$ 2,316,288	$ 2,032,222
Audit-Related Fees (2)	117,146	114,832
Total Fees	$ 2,433,434	$ 2,147,054

(1) Fees for audit services billed in 2016 and 2015 consisted of audits of annual financial statements, comfort letters for securities underwriters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits and non-statutory audit services.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under Item 8 herein. The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under Item 8 herein. The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts

Description (in millions)		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2016	$ 5	$ 12	—	$ 11	$ 6
	2015	7	12	—	14	5
	2014	6	16	—	15	7
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2016	$ 6	$ 5	—	$ 2	$ 9
	2015	5	11	—	10	6
	2014	6	7	—	8	5
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2016	$ 3	$ 6	—	$ 6	$ 3
	2015	4	6	—	7	3
	2014	3	8	—	7	4
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2016	$ 5	$ 5	—	$ 2	$ 8
	2015	3	11	—	9	5
	2014	5	1	—	3	3

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

DATE: February 24, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Vice President and Controller

(Principal Accounting Officer)

Other Directors*:

G. E. Aliff	J. M. Micali
J. A. Bennett	L. M. Miller
J. F. A. V. Cecil	J. W. Roquemore
S. A. Decker	M. K. Sloan
D. M. Hagood	A. Trujillo

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 24, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director

DATE: February 24, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ K. B. Marsh

K. B. Marsh Chairman of the Board, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Vice President and Controller
(Principal Accounting Officer)

Other Directors*:

G. E. Aliff	J. M. Micali
J. A. Bennett	L. M. Miller
J. F. A. V. Cecil	J. W. Roquemore
S. A. Decker	M. K. Sloan
D. M. Hagood	A. Trujillo

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 24, 2017

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	SCE&G	Description
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of December 30, 2016 (Filed herewith)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein)
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein)
4.03	X		First Supplemental Indenture dated as of November 1, 2009 to Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 99.01 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.04		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein)
4.05		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein)
4.06		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein)
4.07		X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)
10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2008 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.03	X	X	Amendment to EPC Contract referred to in Exhibit 10.01 dated October 27, 2015 (Filed as Exhibit 10.05 to Form 10-Q for the quarter ended September 30, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)

*10.04	X	X	SCANA Executive Deferred Compensation Plan (including amendments through November 25, 2014) (Filed as Exhibit 10.03 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.05	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.06	X	X	SCANA Director Compensation and Deferral Plan (including amendments through November 30, 2014) (Filed as Exhibit 10.05 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.07	X	X	SCANA Long-Term Equity Compensation Plan effective February 19, 2015 (Filed as Exhibit 4.05 to Registration Statement No. 333-204218 and incorporated by reference herein)
*10.08	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.09	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.10	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.11	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.12		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.13	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.14	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
10.15	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A., as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.16	X	X	Amended and Restated Three-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.17	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.18	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02		X	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS**	X	X	XBRL Instance Document
101. SCH**	X	X	XBRL Taxonomy Extension Schema
101. CAL**	X	X	XBRL Taxonomy Extension Calculation Linkbase
101. DEF**	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB**	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE**	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Management Contract or Compensatory Plan or Arrangement

** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

Exhibit 3.05

AMENDED AND RESTATED

BYLAWS

OF

SCANA CORPORATION

Adopted on December 30, 2016

ARTICLE I. SHAREHOLDERS

Section 1. *Annual Meeting*. An annual meeting of the shareholders shall be held each fiscal year for the purpose of electing Directors and for the transaction of such other business as may properly come before the meeting. The exact time and place of the annual meeting shall be determined by the Board of Directors.

Section 2. *Special Meetings*. Special meetings of the shareholders may be called by the Chief Executive Officer, or by the Chairman of the Board of Directors, or by a majority of the Board of Directors. Business transacted at a special meeting shall be confined to the specific purpose or purposes of the persons authorized to request such special meeting as set forth in this Section and only such purpose or purposes shall be set forth in the notice of such meeting.

Section 3. *Place of Meeting*. The Board of Directors may designate any place, either within or without the State of South Carolina, as the place of meeting for any annual meeting or for any special meeting.

Section 4. *Conduct of Meetings*. Meetings of shareholders shall be presided over by the Chairman of the Board or, in the absence of the Chairman of the Board, the Chairman of the Executive Committee, or in the absence of the Chairman of the Executive Committee, a chairman designated by the Board of Directors or, in the absence of such designation, by a chairman chosen at the meeting by the vote of a majority in interest of the shareholders present in person or represented by proxy and entitled to vote thereat. The Secretary or, in the Secretary's absence, an Assistant Secretary or, in the absence of the Secretary and all Assistant Secretaries, a person whom the chairman of the meeting shall appoint shall act as secretary of the meeting and keep a record of the proceedings thereof.

The Board of Directors shall be entitled to make such rules, regulations and procedures for the conduct of meetings of shareholders as it shall deem necessary, appropriate or convenient. Subject to such rules, regulations and procedures of the Board of Directors, if any, the chairman of the meeting shall have the right and authority to prescribe such rules, regulations and procedures and to do all such acts as, in the judgment of such chairman, are necessary, appropriate or convenient for the proper conduct of the meeting, including, without limitation, establishing (a) an agenda or order of business for the meeting, (b) rules, regulations and procedures for maintaining order at the meeting and the safety of those present, (c) limitations on participation in such meeting to shareholders of record of the Corporation and their duly authorized and constituted proxies and such other persons as the chairman shall permit, (d) restrictions on entry to the meeting after the time fixed for the commencement thereof, (e) limitations on the time allotted to questions or comments by participants and (f) rules, regulations and procedures governing the opening and closing of the polls for balloting and matters which are to be voted on by ballot. Unless and to the extent determined by the Board of Directors or the chairman of the meeting, meetings of shareholders shall not be required to be held in accordance with rules of parliamentary procedure.

Section 5. *Nominations by Shareholders and Shareholder Proposals – Annual Meeting* . Nominations of persons for election to the Board of Directors and the proposal of business to be considered by the shareholders may be made at an annual meeting of shareholders (a) by or at the direction of the Board of Directors or (b) by any shareholder of the Corporation who was a shareholder of record at the time of giving of notice by such shareholder provided for in this Section, who is entitled to vote at the meeting and who complied with the notice procedures set forth below in this Section.

For nominations or other business to be properly brought before an annual meeting by a shareholder pursuant to clause (b) of the foregoing paragraph of this Section 5, the shareholder must have given timely notice thereof in writing to the Secretary of the Corporation. To be timely, a shareholder's notice shall be delivered to and received by the Secretary at the principal office of the Corporation not less than 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting; provided, however, that if the date of the annual meeting is advanced by more than 30 days or delayed by more than 60 days from the anniversary date of the preceding year's annual meeting, notice by the shareholder to be timely must be so delivered not later than the close of business on the later of (i) the 120^{th} day prior to such annual meeting or (ii) the 10^{th} day following the day on which public announcement of the date of such meeting is first made.

Notwithstanding anything in the second sentence of the preceding paragraph to the contrary, if the number of directors to be elected to the Board of Directors is increased and there is no public announcement naming all of the nominees for director or specifying the size of the increased Board of Directors made by the Corporation at least 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting, a shareholder's notice required by this Bylaw shall also be considered timely, but only with respect to nominees for any new positions created by such increase, if it shall be delivered to and received by the Secretary at the principal office of the Corporation not later than the close of business on the 10^{th} day following the day on which such public announcement is first made by the Corporation.

Such shareholder's notice shall set forth (a) as to each person whom the shareholder proposes to nominate for election or reelection as a director all information relating to such person that is required to be disclosed in solicitations of proxies for election of directors, or is otherwise required, in each case pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) (including such person’s written consent to being named in the proxy statement as a nominee and to serving as a director if elected) and a description of all arrangements and understandings between the nominating shareholder and the nominee or any other person (naming such person) relating to the nomination; (b) as to any other business that the shareholder proposes to bring before the meeting, a brief description of the business desired to be brought before the meeting, the reasons for conducting such business at the meeting and any material interest in such business of such shareholder and the beneficial owner, if any, on whose behalf the proposal is made; (c) as to the shareholder giving the notice and the beneficial owner, if any, on whose behalf the nomination or proposal is made (i) the name and address of such shareholder, as they appear on the Corporation’s books, and of such beneficial owner and (ii) the class and number of shares of the Corporation which are owned beneficially and of record by such shareholder and such beneficial owner.

Only such persons who are nominated in accordance with the procedures set forth in these Bylaws shall be eligible to serve as directors and only such business shall be conducted at an annual meeting of shareholders as shall have been brought before the meeting in accordance with the procedures set forth in this Section. The chairman of the meeting shall have the power and duty to determine whether a nomination or any business proposed to be brought before the meeting was made in accordance with the procedures set forth in this Section and, if any proposed nomination or business is not in compliance with this Section, to declare that such defective proposal shall be disregarded.

For purposes of this Section, “public announcement” shall mean disclosure in a press release reported by the Dow Jones News Service, Associated Press or comparable national news service, or in a document mailed to all shareholders of record.

Section 6. *Nominations at Special Meetings*. Directors are to be elected at a special meeting of shareholders only (a) if the Board of Directors so determines or (b) to fill a vacancy created by the removal of a director at such special meeting. Nominations of persons for election to the Board of Directors may be made at a special meeting of shareholders at which directors are to be elected (a) by or at the direction of the Board of Directors or (b) by any shareholder of the Corporation who was a shareholder of record at the time of giving of notice by such shareholder provided for in this Section, who is entitled to vote at the meeting and who complied with the notice procedures set forth below in this Section.

Nominations by a shareholder of persons for election to the Board of Directors may be made at such a special meeting of shareholders at which directors are to be elected if the shareholder's notice required by the fourth paragraph of Section 5 of Article I of these Bylaws shall be delivered to and received by the Secretary of the Corporation at the principal office of the Corporation not earlier than the 120th day prior to such special meeting and not later than the close of business on the later of the 90th day prior to such special meeting or the 10th day following the day on which public announcement (as defined in Section 5 of Article I of these Bylaws) is first made of the date of the special meeting and of the nominees proposed by the Board of Directors to be elected at such meeting.

Only such persons who are nominated in accordance with the procedures set forth in these Bylaws shall be eligible to serve as directors and only such business shall be conducted at a special meeting of shareholders as shall have been brought before the meeting in accordance with the procedures set forth in Section 2 of this Article I. The chairman of the meeting shall have the power and duty to determine whether a nomination or any business proposed to be brought before the special meeting was made in accordance with the procedures set forth in this Section and, if any proposed nomination or business is not in compliance with this Section, to declare that such defective proposal shall be disregarded.

Section 7. *Proxy Access for Director Nominations*.

(a) Subject to the terms and conditions of these Bylaws, the Corporation shall include in its proxy statement and on its form of proxy for an annual meeting of shareholders the name of, and shall include in its proxy statement the Required Information (as defined below) relating to, any nominee for election to the Board delivered pursuant to this Section 7 (a "Shareholder Nominee") who satisfies the eligibility requirements in this Section 7, and who is identified in a timely and proper notice that both complies with this Section 7 (the "Shareholder Notice") and is given by a shareholder on behalf of one or more shareholders or on behalf of any affiliate, associate of, or any other party acting in concert with or on behalf of one or more shareholders nominating a Shareholder Nominee or beneficial owners on whose behalf such shareholder(s) is acting (an "Associated Person"), but in no case more than twenty shareholders or beneficial owners, that:

(i) expressly elect at the time of the delivery of the Shareholder Notice to have such Shareholder Nominee included in the Corporation's proxy materials,

(ii) as of the date of the Shareholder Notice, own and continuously have owned during the three prior years at least three percent (3%) of the outstanding shares of common stock of the Corporation entitled to vote in the election of directors (the "Required Shares"), and

(iii) satisfy the additional requirements in these Bylaws (an "Eligible Shareholder").

(b) For purposes of qualifying as an Eligible Shareholder and satisfying the ownership requirements under Section 7(a):

(i) the outstanding shares of common stock of the Corporation owned by one or more shareholders and beneficial owners that each shareholder and/or beneficial owner has owned continuously for at least three years as of the date of the Shareholder Notice may be aggregated, provided that the number of shareholders and Associated Persons whose ownership of shares is aggregated for such purpose shall not exceed twenty (20) and that any and all requirements and obligations for an Eligible Shareholder set forth in this Section 7 are satisfied by and as to each such shareholder and Associated Persons (except as noted with respect to aggregation or as otherwise provided in this Section 7), and

(ii) a group of funds that are (1) under common management and investment control, (2) under common management and funded primarily by the same employer, or (3) a "group of investment companies," as such term is defined in Section 12(d)(1)(G)(ii) of the Investment Company Act of 1940, as amended (a "Qualifying Fund") shall be treated as one shareholder, provided that each fund included within a Qualifying Fund otherwise meets the requirements set forth in this Section 7.

(c) For purposes of this Section 7:

(i) A shareholder or beneficial owner shall be deemed to own only those outstanding shares of common stock of the Corporation as to which such person possesses both (i) the full voting and investment rights pertaining to the shares and (ii) the full economic interest in (including the opportunity for profit and risk of loss on) such shares; provided that the number of shares calculated in accordance with clauses (i) and (ii) shall not include any shares (A) sold by such person or any of its affiliates in any transaction that has not been settled or closed, including any short sale, (B) borrowed by such person or any of its affiliates for any purposes or purchased by such person or any of its affiliates pursuant to an agreement to resell, or (C) subject to any option, warrant, forward contract, swap, contract of sale, or other derivative or similar agreement entered into by such person or any of its affiliates, whether any such instrument or agreement is to be settled with shares or with cash based on the notional amount or value of outstanding shares of Common Stock, in any such case which instrument or agreement has, or is intended to have the purpose or effect of (1) reducing in any manner, to any extent or at any time in the future, such person's or its affiliates' full right to vote or direct the voting of any such shares, and/or (2) hedging, offsetting, or altering to any degree any gain or loss arising from the full economic ownership of such shares by such person or its affiliate.

(ii) A shareholder or beneficial owner shall be deemed to own shares held in the name of a nominee or other intermediary so long as the shareholder or beneficial owner retains the right to instruct how the shares are voted with respect to the election of directors and possesses the full economic interest in the shares. A person's ownership of shares shall be deemed to continue during any period in which the person has delegated any voting power by means of a proxy, power of attorney, or other instrument or arrangement that is revocable at any time by the person.

(iii) A shareholder or beneficial owner's ownership of shares shall be deemed to continue during any period in which the person has loaned such shares provided that the person has the power to recall such loaned shares on five business days' notice and has recalled such loaned shares as of the date of the Shareholder Notice and through the date of the annual meeting.

Whether outstanding shares of the Corporation are owned for these purposes shall be determined by the Board.

(d) No shareholder or beneficial owner, alone or together with any Associated Person, may be a member of more than one group constituting an Eligible Shareholder under this Section 7.

(e) For purposes of this Section 7, the "Required Information" that the Corporation will include in its proxy statement is:

(i) the information concerning the Shareholder Nominee and the Eligible Shareholder that is required to be disclosed in the Corporation's proxy statement by the applicable requirements of the Exchange Act and the rules and regulations thereunder; and

(ii) if the Eligible Shareholder so elects, a written statement of the Eligible Shareholder, not to exceed 500 words, in support of each Shareholder Nominee, which must be provided at the same time as the Shareholder Notice for inclusion in the Corporation's proxy statement for the annual meeting (the "Statement").

Notwithstanding anything to the contrary contained in this Section 7, the Corporation may omit from its proxy materials any information or Statement (or portion thereof) that the Corporation, in good faith, believes (i) would violate any applicable law, rule, regulation or listing standard, or (ii) is not true and correct in all material respects or omits to state a material fact necessary in order to make the statements made, in light of the circumstances under which they were made, not misleading. Nothing in this Section 7 shall limit the Corporation's ability to solicit against and include in its proxy materials its own statements relating to any Eligible Shareholder or Shareholder Nominee.

(f) The Shareholder Notice shall include the following information:

(i) the written consent of each Shareholder Nominee to being named in the Corporation's proxy materials as a nominee and to serving as a director if elected;

(ii) a copy of the Schedule 14N that has been or concurrently is filed with the SEC under Exchange Act Rule 14a-18;

(iii) a description of all arrangements or understandings between the Eligible Shareholder and each Shareholder Nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the Eligible Shareholder;

(iv) such information about the Shareholder Nominee as would have been required to be included in a proxy statement filed pursuant to the proxy rules of the SEC had each Shareholder Nominee been nominated, or intended to be nominated, by the Board;

(v) the written agreement of the Eligible Shareholder (in the case of a group, each shareholder or beneficial owner whose shares are aggregated for purposes of constituting an Eligible Shareholder) addressed to the Corporation, setting forth the following additional agreements, representations, and warranties:

(A) certifying to the number of shares of common stock of the Corporation it owns and has owned (as defined in Section 7(c) of these Bylaws) continuously for at least three years as of the date of the Shareholder Notice and agreeing to continue to own such shares through the annual meeting, which statement shall also be included in the Schedule 14N filed by the Eligible Shareholder with the SEC;

(B) the Eligible Shareholder's agreement to provide written statements from the record holder and intermediaries as required under Section 7(h) verifying the Eligible Shareholder's continuous ownership of the Required Shares through and as of the business day immediately preceding the date of the annual meeting;

(C) The Eligible Shareholder's agreement to appear in person or by legal proxy at the annual meeting to nominate the Shareholder Nominee; and

(D) the Eligible Shareholder's representation and warranty that the Eligible Shareholder (including each member of any group of shareholders and/or Associated Persons that together is an Eligible Shareholder) (1) acquired the Required Shares in the ordinary course of business and not with the intent to change or influence control of the Corporation, and does not presently have any such intent, (2) has not nominated and will not nominate for election to the Board at the annual meeting any person other than the Shareholder Nominee(s) being nominated pursuant to this Section 7, (3) has not engaged and will not engage in, and has not been and will not be a participant (as defined in Item 4 of Exchange Act Schedule 14A) in, a solicitation within the meaning of Exchange Act Rule 14a-1(l), in support of the election of any individual as a director at the annual meeting other than its Shareholder Nominee or a nominee of the Board, and (4) will not distribute any form of proxy for the annual meeting other than the form distributed by the Corporation; and

(vi) the Eligible Shareholder's agreement to (1) assume all liability stemming from any legal or regulatory violation arising out of the Eligible Shareholder's communications with the shareholders of the Corporation or out of the information that the Eligible Shareholder provided to the Corporation, (2) indemnify and hold harmless the Corporation and each of its directors, officers and employees individually against any liability, loss or damages in connection with any threatened or pending action, suit or proceeding, whether legal, administrative or investigative, against the Corporation or any of its directors, officers or employees arising out of any nomination submitted by the Eligible Shareholder pursuant to this Section 7, (3) comply with all other laws, rules, regulations and listing standards applicable to any solicitation in connection with the annual meeting, (4) file all materials described in Section 7(h)(iii) with the SEC, regardless of whether any such filing is required under Exchange Act Regulation 14A, or whether any exemption from filing is available for such materials under Exchange Act Regulation 14A, and (5) provide to the Corporation promptly and prior to the annual meeting such additional information as necessary or reasonably requested by the Corporation, and in the case of a nomination by a group of shareholders or beneficial owners that together is an Eligible Shareholder, the designation by all group members of one group member that is authorized to act on behalf of all such members with respect to the nomination and matters related thereto, including withdrawal of the nomination.

(g) To be timely under this Section 7, the Shareholder Notice must be received by the Secretary of the Corporation at the principal executive offices of the Corporation not later than the 120th day nor earlier than the 150th day prior to the first anniversary of the date the definitive proxy statement was first sent to shareholders in connection with the preceding year's annual meeting of shareholders; provided, however, that in the event the date of the annual meeting is advanced by more than 30 days or delayed by more than 60 days from such anniversary date, or if no annual meeting was held in the preceding year, to be timely the Shareholder Notice must be so delivered not later than the close of business on the later of (i) the 120th day prior to the date of such annual meeting or (ii) the 10th day following the day on which the date of such meeting is first publicly announced by the Corporation. In no event shall an adjournment or recess of an annual meeting, or a postponement of an annual meeting for which notice has been given or with respect to which there has been a public announcement of the date of the meeting, commence a new time period (or extend any time period) for the giving of the Shareholder Notice.

(h) An Eligible Shareholder must:

(i) within five business days after the date of the Shareholder Notice, provide one or more written statements from the record holder(s) of the Required Shares and from each intermediary through which the Required Shares are or have been held, in each case during the requisite three year holding period, specifying the number of shares that the Eligible Shareholder owns, and has owned continuously, in compliance with this Section 7;

(ii) include in the Schedule 14N filed with the SEC a statement certifying that it owns and continuously has owned the Required Shares for at least three years;

(iii) file with the SEC any solicitation or other communication by or on behalf of the Eligible Shareholder relating to the Corporation's annual meeting of shareholders, one or more of the Corporation's directors or director nominees or any Shareholder Nominee, regardless of whether any such filing is required under Exchange Act Regulation 14A or whether any exemption from filing is available for such solicitation or other communication under Exchange Act Regulation 14A; and

(iv) as to any group of funds whose shares are aggregated for purposes of constituting an Eligible Shareholder, within five business days after the date of the Shareholder Notice, provide documentation reasonably satisfactory to the Corporation that demonstrates that the funds satisfy Section 7(b)(ii).

The information provided pursuant to this Section 7(h) shall be deemed part of the Shareholder Notice for purposes of this Section 7.

(i) Within the time period prescribed in Section 7(g) for delivery of the Shareholder Notice, the Eligible Shareholder must also deliver to the Secretary of the Corporation at the principal executive offices of the Corporation a written representation and agreement (which shall be deemed part of the Shareholder Notice for purposes of this Section 7) signed by each Shareholder Nominee and representing and agreeing that such Shareholder Nominee:

(i) is not and will not become a party to any agreement, arrangement, or understanding with, and has not given any commitment or assurance to, any person or entity as to how such Shareholder Nominee, if elected as a director, will act or vote on any issue or question;

(ii) is not and will not become a party to any agreement, arrangement, or understanding with any person with respect to any direct or indirect compensation, reimbursement, or indemnification in connection with service or action as a director that has not been disclosed to the Corporation;

(iii) if elected as a director, will comply with all of the Corporation's corporate governance, conflict of interest, confidentiality, and stock ownership and trading policies and guidelines, and any other Corporation policies and guidelines applicable to directors; and

(iv) will not provide any non-public information regarding the Corporation to any third party other than the Corporation's auditors, legal counsel or the SEC.

At the request of the Corporation, the Shareholder Nominee must promptly, but in any event within five business days after such request, submit (i) all completed and signed questionnaires required of the Corporation's directors, (ii) a written consent to the Corporation's following such processes for evaluation as the Corporation follows in evaluating any other potential Board Nominee, and (iii) such other information as the Corporation may reasonably request. The Corporation may request such additional information as necessary to permit the Board to determine if each Shareholder Nominee satisfies this Section 7.

(j) In the event that any information or communications provided by the Eligible Shareholder or any Shareholder Nominees to the Corporation or its shareholders is not, when provided, or thereafter ceases to be, true, correct and complete in all material respects (including omitting a material fact necessary to make the statements made, in light of the circumstances under which they were made, not misleading), each Eligible Shareholder or Shareholder Nominee, as the case may be, shall promptly notify the Secretary of the Corporation and provide the information that is required to make such information or communication true, correct, complete and not misleading; it being understood that providing any such notification shall not be deemed to cure any such defect or limit the Corporation's right to omit a Shareholder Nominee from its proxy materials pursuant to this Section 7.

Notwithstanding anything to the contrary contained in this Section 7, a Shareholder Nominee shall be disqualified from serving as a director of the Corporation, and the Corporation may omit any such Shareholder Nominee from its proxy materials, and such nomination shall be disregarded and no vote on such Shareholder Nominee will occur, notwithstanding that proxies in respect of such vote may have been received by the Corporation, if:

(i) the Eligible Shareholder or Shareholder Nominee breaches any of its respective agreements, representations, or warranties set forth in the Shareholder Notice (or otherwise submitted pursuant to this Section 7), any of the information in the Shareholder Notice (or otherwise submitted pursuant to this Section 7) was not, when provided, true, correct and complete, or the requirements of this Section 7 have otherwise not been met;

(ii) the Shareholder Nominee is not independent under the listing standards of the principal U.S. exchange upon which the shares of the Corporation are listed, any applicable rules of the SEC, and the Corporation's Governance Principles;

(iii) the Shareholder Nominee is or has been, within the past three (3) years, an officer or director of a competitor, as defined in Section 8 of the Clayton Antitrust Act of 1914;

(iv) the Shareholder Nominee is a named subject of a pending criminal proceeding (excluding traffic violations and other minor offenses) or has been convicted in such a criminal proceeding within the past ten years;

(v) a notice is delivered to the Corporation (whether or not subsequently withdrawn) indicating that a shareholder intends to nominate any candidate for election to the Board pursuant to the Board's director nomination process;

(vi) the election of the Shareholder Nominee to the Board would cause the Corporation to be in violation of the Articles of

Incorporation, these Bylaws, or any applicable state or federal law, rule, or regulation or any applicable listing standard.

(vii) the Shareholder Nominee has any interlocking relationships or affiliations prohibited by the rules and regulations of the Federal Energy Regulatory Commission.

(k) The maximum number of Shareholder Nominees that may be included in the Corporation's proxy materials pursuant to this Section 7 shall not exceed the greater of (i) two or (ii) twenty percent (20%) of the number of directors in office as of the last day on which a Shareholder Notice may be delivered pursuant to this Section 7 with respect to the annual meeting, or if such amount is not a whole number, the closest whole number below twenty percent (20%). If directors are to be elected at an annual meeting for terms of office longer than one year or until the next annual meeting, the maximum number of Shareholder Nominees that may be included in the Corporation's proxy materials pursuant to this Section 7 shall not exceed the greater of (i) one or (ii) twenty percent (20%) of the number of directors to be elected at such annual meeting, or if such amount is not a whole number, the closest whole number below twenty percent (20%). However, the maximum number of Shareholder Nominees that may be included in the Corporation's proxy materials pursuant to this Section 7 shall be reduced by any (i) Shareholder Nominee whose name was submitted for inclusion in the Corporation's proxy materials pursuant to this Section 7 but either is subsequently withdrawn or that the Board of Directors decides to nominate as a Board nominee and (ii) any Shareholder Nominee elected to the Board of Directors at either of the two preceding annual meetings who are standing for reelection at the nomination of the Board of Directors. In the event that one or more vacancies for any reason occurs after the deadline in Section 7(g) for delivery of the

Shareholder Notice but before the annual meeting and the Board resolves to reduce the size of the Board in connection therewith, the maximum number shall be calculated based on the number of directors in office as so reduced. In the event that the number of Shareholder Nominees submitted by Eligible Shareholders pursuant to this Section 7 exceeds this maximum number, the Corporation shall determine which Shareholder Nominees shall be included in the Corporation's proxy materials in accordance with the following provisions: each Eligible Shareholder (or in the case of a group, each group constituting an Eligible Shareholder) will select one Shareholder Nominee for inclusion in the Corporation's proxy materials until the maximum number is reached, going in order of the amount (largest to smallest) of shares of the Corporation each Eligible Shareholder disclosed as owned in its respective Shareholder Notice submitted to the Corporation. If the maximum number is not reached after each Eligible Shareholder (or in the case of a group, each group constituting an Eligible Shareholder) has selected one Shareholder Nominee, this selection process will continue as many times as necessary, following the same order each time, until the maximum number is reached. Following such determination, if any Shareholder Nominee who satisfies the eligibility requirements in this Section 7 is thereafter nominated by the Board, and thereafter is not included in the Corporation's proxy materials or thereafter is not submitted for director election for any reason (including the Eligible Shareholder's or Shareholder Nominee's failure to comply with this Section 7), no other nominee or nominees shall be included in the Corporation's proxy materials or otherwise submitted for director election in substitution thereof.

(l) Any Shareholder Nominee who is included in the Corporation's proxy materials for a particular annual meeting of shareholders but either (i) withdraws from or becomes ineligible or unavailable for election at the annual meeting for any reason, including for the failure to comply with any provision of these Bylaws or (ii) does not receive votes at least equal to twenty-five percent (25%) of the shares voting for director candidates, will be ineligible to be a Shareholder Nominee pursuant to this Section 7 for the next two annual meetings.

(m) The Board (and any other person or body authorized by the Board) shall have the power and authority to interpret this Section 7 and to make any and all determinations necessary or advisable to apply this Section 7 to any persons, facts or circumstances, including the power to determine (i) whether one or more shareholders or beneficial owners qualifies as an Eligible Shareholder, (ii) whether a Shareholder Notice complies with this Section 7 and has otherwise met the requirements of this Section 7, (iii) whether a Shareholder Nominee satisfies the qualifications and requirements in this Section 7, and (iv) whether any and all requirements of this Section 7 (or any applicable requirements of the Board's director nomination process) have been satisfied. Any such interpretation or determination adopted in good faith by the Board (or any other person or body authorized by the Board) shall be binding on all persons, including the Corporation and its shareholders (including any beneficial owners). Notwithstanding the foregoing provisions of this Section 7, unless otherwise required by law or otherwise determined by the chairman of the meeting or the Board, if (i) the Eligible Shareholder or (ii) a qualified representative of the shareholder does not appear at the annual meeting of shareholders of the Corporation to present its Shareholder Nominee or Shareholder Nominees, such nomination or nominations shall be disregarded, notwithstanding that proxies in respect of the election of the Shareholder Nominee or Shareholder Nominees may have been received by the Corporation. This Section 7 shall be the exclusive method for shareholders to include nominees for director election in the

Corporation's proxy materials.

ARTICLE II. BOARD OF DIRECTORS

Section 1. *General Powers*. The business and affairs of the Corporation shall be managed under the direction of its Board of Directors.

Section 2. *Number, Tenure and Qualifications*. The number of Directors of the Corporation shall be not less than nine and not more than twenty as determined from time to time by the Board of Directors. Directors need not be residents of the State of South Carolina. Directors shall be required to own a number of shares of the Corporation's common stock equal to the number of shares granted in the five most recent annual retainers for Directors. Persons serving as independent directors as of February 1, 2009 shall be required to meet the minimum share ownership requirement by the last day of February 2014. Persons who are subsequently elected as directors shall be required to meet such requirement within six years following the date of their election to the Board of Directors. The Nominating and Governance Committee of the Board of Directors, or such other committee of the Board of Directors as the Board of Directors shall designate, shall have the discretion to grant a temporary waiver of these minimum share ownership requirements upon demonstration by a director that, due to a financial hardship or other good reason, he or she cannot meet the minimum share ownership requirements.

Section 3. *Regular Meetings*. The Board of Directors may provide, by resolution, the time and place, either within or without the State of South Carolina, for the holding of additional regular meetings.

Section 4. *Special Meetings*. Special meetings of the Board of Directors may be held at any time and place upon the call of the Chairman of the Board or of the Chief Executive Officer or by action of the Executive Committee or Audit Committee.

Section 5. *Quorum*. A majority of the number of Directors fixed as provided in Section 2 of this Article II shall constitute a quorum for the transaction of business at any meeting of the Board of Directors, but if less than a quorum is present at a meeting, a majority of the Directors present may adjourn the meeting from time to time without further notice.

Section 6. *Committees*. The Board of Directors may create one or more committees of the Board of Directors including an Audit Committee and an Executive Committee, and appoint members of the Board of Directors to serve on them. To the extent specified by the Board of Directors and subject to such limitations as may be specified by law, the Corporation's Articles of Incorporation or these Bylaws, such committees may exercise all of the authority of the Board of Directors in the management of the Corporation.

Meetings of a committee may be held at any time on call of the Chief Executive Officer or of any member of the committee. A majority of the members shall constitute a quorum for all meetings.

Section 7. *Compensation*. The Board of Directors may authorize payment to Directors of compensation for serving as Director, except that Directors who are also salaried officers of the Corporation or of any affiliated company shall not receive additional compensation for service as Directors. The Board of Directors may also authorize the payment of, or reimbursement for, all expenses of each Director related to such Director's attendance at meetings.

ARTICLE III. OFFICERS

Section 1. *Titles*. The officers of the Corporation shall be a Chairman of the Board, a Chief Executive Officer, a Chief Operating Officer, a Chief Financial Officer, a Treasurer, a General Counsel, a Secretary, a Corporate Compliance Officer, an Internal Auditor and such other officers and assistant officers as the Board of Directors or the Chief Executive Officer shall deem necessary or desirable. Any two or more offices may be held by the same person, and an officer may act in more than one capacity where action of two or more officers is required.

Section 2. _Appointment of Officers_. The Board of Directors shall appoint the Chairman of the Board, the Chief Executive Officer, the Chief Operating Officer, the Chief Financial Officer, the Treasurer, the General Counsel, the Secretary, the Corporate Compliance Officer, the Internal Auditor and such other officers and assistant officers as the Board of Directors shall deem necessary or desirable at such time or times as the Board of Directors shall determine. In the absence of any action by the Board of Directors, the Chief Executive Officer may appoint all other officers.

Section 3. _Removal_. Any officer appointed by the Board of Directors or the Chief Executive Officer may be removed by the Board of Directors or the Executive Committee, but no other committee, with or without cause. The Chief Executive Officer may remove any officer other than the Corporate Compliance Officer and the Internal Auditor.

Section 4. _Chairman of the Board_. The Chairman of the Board shall be chosen by and from among the Directors, shall preside at all meetings of the Board of Directors if present, and shall, in general, perform all duties incident to the office of Chairman of the Board and such other duties as, from time to time, may be assigned to him by the Board of Directors.

Section 5. _Chief Executive Officer_. The Chief Executive Officer, subject to the control of the Board of Directors, shall in general supervise and control all of the business and affairs of the Corporation. He shall, in the absence of the Chairman of the Board and the Chairman of the Executive Committee, preside at meetings of the Board of Directors. He may vote on behalf of the Corporation the stock of any other corporation owned by the Corporation and sign, with the Secretary or any other proper officer of the Corporation thereunto authorized by the Board of Directors, certificates for shares of the Corporation and any deeds, mortgages, bonds, contracts or other instruments which the Board of Directors has authorized to be executed, except in cases where the signing and execution thereof shall be expressly delegated by the Board of Directors or by these Bylaws to some other officer or agent of the Corporation, or shall be required by law to be otherwise signed or executed; and in general shall perform all duties incident to the office of Chief Executive Officer and such other duties as may be prescribed by the Board of Directors from time to time. The Chief Executive Officer may delegate his authority to vote stock on behalf of the Corporation and such delegation of authority may be either general or specific.

Section 6. *Chief Operating Officer*. The Chief Operating Officer shall in general perform all of the duties incident to the office of Chief Operating Officer and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 7. *Chief Financial Officer*. The Chief Financial Officer shall in general perform all of the duties incident to the office of Chief Financial Officer and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 8. *Treasurer*. The Treasurer shall in general perform all of the duties incident to the office of Treasurer and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 9. *General Counsel*. The General Counsel shall in general perform all of the duties incident to the office of the General Counsel and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 10. *Secretary*. The Secretary shall: (a) keep the minutes of the meetings of the shareholders and of the Board of Directors in one or more books provided for that purpose; (b) authenticate records of the Corporation when such authentication is required; and (c) in general perform all duties incident to the office of the Secretary and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 11. *Corporate Compliance Officer*. The Corporate Compliance Officer shall report to the Chairman of the Audit Committee and shall in general perform all of the duties incident to the office of Corporate Compliance Officer and such other duties as from time to time may be assigned to him by the Board of Directors or the Audit Committee, but no other committee.

Section 12. *Internal Auditor*. The Internal Auditor shall report to the Chairman of the Audit Committee and shall in general perform all of the duties incident to the office of Internal Auditor and such other duties as from time to time may be assigned to him by the Board of Directors or the Audit Committee, but no other committee.

Section 13. *Compensation*. The compensation of the officers appointed by the Board of Directors shall be fixed from time to time by the Board of Directors and the compensation of those appointed by the Chief Executive Officer shall, in the absence of any action by the Board of Directors, be set by the Chief Executive Officer. No officer shall be prevented from receiving compensation by reason of the fact that he is also a Director of the Corporation.

ARTICLE IV. AMENDMENTS

Except as otherwise provided by law, these Bylaws may be amended or repealed and new Bylaws may be adopted by the Board of Directors or the shareholders.

Exhibit 12.01

COMPUTATION OF RATIOS
December 31, 2016

BOND RATIO

SCANA and SCE&G:

Dollars in Millions		
Year Ended December 31, 2016		
Net earnings as defined in SCE&G's bond indenture dated April 1, 1993 (Mortgage)		$ 1,311.3
Divide by annualized interest charges on:		
Bonds outstanding under the Mortgage	$ 256.0	
Total annualized interest charges	256.0	
Bond Ratio		5.12

RATIO OF EARNINGS TO FIXED CHARGES

Dollars in Millions	**SCANA**					**SCE&G**				
Years Ended December 31,	**2016**	**2015**	**2014**	**2013**	**2012**	**2016**	**2015**	**2014**	**2013**	**2012**
Fixed Charges as defined:										
Interest on debt	$356.8	$327.8	$318.2	$305.9	$301.3	$284.6	$258.4	$237.6	$226.4	$217.4
Amortization of debt premium, discount and expense (net)	4.5	4.7	9.7	5.3	4.9	3.5	3.7	4.4	4.2	3.9
Interest component on rentals	3.5	3.7	4.1	4.9	4.9	4.0	4.1	4.0	4.5	3.2
Total Fixed Charges (A)	$364.8	$336.2	$332.0	$316.1	$311.1	$292.1	$266.2	$246.0	$235.1	$224.5
Earnings as defined:										
Pretax income from continuing operations	$865.6	$1138.4	$786.0	$693.8	$601.6	$774.1	$711.0	$676.0	$579.7	$509.5
Total fixed charges above	364.8	336.2	332.0	316.1	311.1	292.1	266.2	246.0	235.1	224.5
Pretax equity in (earnings) losses of investees	(0.7)	0.8	(1.4)	(3.2)	(3.3)	3.1	5.0	5.3	3.5	3.8
Cash distributions from equity investees	3.7	4.0	7.4	9.6	3.3	-	-	-	-	-
Total Earnings (B)	$1,233.4	$1,479.4	$1,124.0	$1016.3	$912.7	$1069.3	$982.2	$927.3	$818.3	$737.8
Ratio of Earnings to Fixed Charges (B/A)	3.38	4.40	3.39	3.22	2.93	3.66	3.69	3.77	3.48	3.29

Exhibit 21.01

Each of the following subsidiaries of SCANA is incorporated in the state of South Carolina, except as otherwise indicated.

South Carolina Electric & Gas Company
South Carolina Generating Company, Inc.
South Carolina Fuel Company, Inc.
Public Service Company of North Carolina, Incorporated
SCANA Energy Marketing, Inc.
SCANA Services, Inc.
SCANA Communications Holdings, Inc., incorporated in the State of Delaware
SCANA Corporate Security Services, Inc.

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-191691, 333-204218 and 333-213797 on Form S-8 and Registration Statement Nos. 333-206629 and 333-213798 on Form S-3 of our reports dated February 24, 2017, relating to the consolidated financial statements and financial statement schedule of SCANA Corporation and subsidiaries (the “Company”), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2016.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-206629-01 on Form S-3 of our report dated February 24, 2017, relating to the consolidated financial statements and financial statement schedule of South Carolina Electric & Gas Company and affiliates appearing in this Annual Report on Form 10-K of South Carolina Electric & Gas Company for the year ended December 31, 2016.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

Exhibit 24.01

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of SCANA Corporation ("SCANA"), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCANA's fiscal year ended December 31, 2016, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 16th day of February 2017.

/s/G. E. Aliff	/s/J. A. Bennett
G. E. Aliff Director	J. A. Bennett Director
/s/J. F. A. V. Cecil	/s/S. A. Decker
J. F. A. V. Cecil Director	S. A. Decker Director
/s/D. M. Hagood	/s/K. B. Marsh
D. M. Hagood Director	K. B. Marsh Director
/s/J. M. Micali	/s/L. M. Miller
J. M. Micali Director	L. M. Miller Director
/s/J. W. Roquemore	/s/M. K. Sloan
J. W. Roquemore Director	M. K. Sloan Director
/s/A. Trujillo	
A. Trujillo Director	

Exhibit 24.02

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of South Carolina Electric & Gas Company ("SCE&G"), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCE&G's fiscal year ended December 31, 2016, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 16th day of February 2017.

/s/G. E. Aliff
G. E. Aliff
Director

/s/J. A. Bennett
J. A. Bennett
Director

/s/J. F. A. V. Cecil
J. F. A. V. Cecil
Director

/s/S. A. Decker
S. A. Decker
Director

/s/D. M. Hagood
D. M. Hagood
Director

/s/K. B. Marsh
K. B. Marsh
Director

/s/J. M. Micali
J. M. Micali
Director

/s/L. M. Miller
L. M. Miller
Director

/s/J. W. Roquemore
J. W. Roquemore
Director

/s/M. K. Sloan
M. K. Sloan
Director

/s/A. Trujillo
A. Trujillo
Director

Exhibit 31.01

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 24, 2017

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board, President,
Chief Executive Officer and Chief Operating Officer

Exhibit 31.02

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

February 24, 2017

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 31.03

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 24, 2017

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board and Chief Executive Officer

Exhibit 31.04

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 24, 2017

/s/Jimmy E. Addison

Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 32.01

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the "Company") on Form 10-K for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2017

/s/Kevin B. Marsh	/s/Jimmy E. Addison
Kevin B. Marsh	Jimmy E. Addison
Chairman of the Board, President, Chief Executive Officer and Chief Operating Officer	Executive Vice President and Chief Financial Officer

Exhibit 32.02

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of South Carolina Electric & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2017

/s/Kevin B. Marsh	/s/Jimmy E. Addison
Kevin B. Marsh	Jimmy E. Addison
Chairman of the Board and Chief Executive Officer	Executive Vice President and Chief Financial Officer

FORM 10-K

SOUTH CAROLINA ELECTRIC & GAS CO - SCG

Filed: February 23, 2018 (period: December 31, 2017)

Annual report with a comprehensive overview of the company

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2017

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	**SCANA Corporation** (a South Carolina corporation)	**57-0784499**
1-3375	**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	**57-0248695**

Securities registered pursuant to Section 12(b) of the Act: SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $9.5 billion at June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $67.01 per share. South Carolina Electric & Gas Company is a wholly-owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 20, 2018
SCANA Corporation	Without Par Value	142,638,371
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Information required by Items 10-13 of Part III of this Form 10-K will be incorporated by reference to SCANA Corporation's definitive proxy statement with respect to its 2018 Annual Meeting of Shareholders, if such definitive proxy statement is filed with the Securities and Exchange Commission on or before April 30, 2018. Due to the pending merger with Dominion Energy, Inc., we may not be required to file a definitive proxy statement with regard to such meeting or may file it after April 30, 2018, in which case we will file an amendment to this Form 10-K on or before April 30, 2018 to include the information that would otherwise be incorporated by reference.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. South Carolina Electric & Gas Company makes no representation as to information relating to SCANA Corporation or its subsidiaries (other than South Carolina Electric & Gas Company and its consolidated affiliates).
South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning the proposed merger with Dominion Energy, recovery of Nuclear Project abandonment costs, key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated capital and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "targets," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements due to the information being of a preliminary nature and subject to further and/or continuing review and adjustment. Other important factors that could cause such material differences include, but are not limited to, the following:

(1) the occurrence of any event, change or other circumstances that could give rise to the failure by SCANA and its subsidiaries (the Company) to consummate the proposed merger with Dominion Energy; (2) the ability of the Company to recover through rates the costs expended on Unit 2 and Unit 3, and a reasonable return on those costs, under the abandonment provisions of the BLRA or through other means; (3) uncertainties relating to the bankruptcy filing by WEC and WECTEC; (4) further changes in tax laws and realization of tax benefits and credits, and the ability or inability to realize credits and deductions, particularly in light of the abandonment of Unit 2 and Unit 3; (5) legislative and regulatory actions, particularly changes related to electric and gas services, rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations including any imposition of fees or taxes on carbon emitting generating facilities, the BLRA, and any actions affecting the abandonment of Unit 2 and Unit 3; (6) current and future litigation, including particularly litigation or government investigations or actions involving or arising from the construction or abandonment of Unit 2 and Unit 3 or arising from the proposed merger with Dominion Energy; (7) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity, and the effect of rating agency actions on the Company's cost of and access to capital and sources of liquidity; (8) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed which may be highly specialized or in short supply, at agreed upon quality and prices, for our construction program, operations and maintenance; (9) the results of efforts to ensure the physical and cyber security of key assets and processes; (10) changes in the economy, especially in areas served by subsidiaries of SCANA; (11) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets; (12) the impact of conservation and demand side management efforts and/or technological advances on customer usage; (13) the loss of electricity sales to distributed generation, such as solar photovoltaic systems or energy storage systems; (14) growth opportunities for SCANA's regulated and other subsidiaries; (15) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries are located and in areas served by SCANA's subsidiaries; (16) changes in SCANA's or its subsidiaries' accounting rules and accounting policies; (17) payment and performance by counterparties and customers as contracted and when due; (18) the results of efforts to license, site, construct and finance facilities, and to receive related rate recovery, for generation and transmission; (19) the results of efforts to operate the Company's electric and gas systems and assets in accordance with acceptable performance standards, including the impact of additional distributed generation; (20) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power; (21) the availability of skilled, licensed and experienced human resources to properly manage, operate, and grow the Company's businesses, particularly in light of uncertainties with respect to legislative and regulatory actions surrounding recovery of Nuclear Project costs and the announced potential merger; (22) labor disputes; (23) performance of SCANA's pension plan assets and the effect(s) of associated discount rates; (24) inflation or deflation; (25) changes in interest rates; (26) compliance with regulations; (27) natural disasters, man-made mishaps and acts of terrorism that directly affect our operations or the regulations governing them; and (28) the other risks and uncertainties described from time to time in the reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
BACT	Best Available Control Technology
Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CGT	Carolina Gas Transmission Corporation
CIAC	Contributions In Aid of Construction
Citibank	Citibank, N.A.
CO_2	Carbon Dioxide
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of WEC and WECTEC
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker (decoupling mechanism)
CWA	Clean Water Act
DECG	Dominion Energy Carolina Gas Transmission LLC
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
District Court	United States District Court for the District of South Carolina
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
Dominion Energy	Dominion Energy, Inc.
DOR	South Carolina Department of Revenue
DOT	United States Department of Transportation
DSM Programs	Electric Demand Side Management Programs
ELG Rule	Federal effluent limitation guidelines for steam electric generating units
EMANI	European Mutual Association for Nuclear Insurance
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008, as amended by the October 2015 Amendment
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
FILOT	Fee in Lieu of Taxes
Fluor	Fluor Corporation
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
Interim Assessment Agreement	Interim Assessment Agreement dated March 28, 2017, as amended, among SCE&G, Santee Cooper, WEC and WECTEC
IRC	Internal Revenue Code of 1986, as amended

IRS	Internal Revenue Service
Joint Petition	Joint application and petition of SCE&G and Dominion Energy for review and approval of a proposed business combination as set forth in the Merger Agreement and for a prudency determination regarding the abandonment of the Nuclear Project and associated merger benefits and cost recovery plans, filed with the SCPSC on January 12, 2018
kWh	Kilowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LNG	Liquefied Natural Gas
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF	Thousand Cubic Feet
MGP	Manufactured Gas Plant
Merger Agreement	Agreement and Plan of Merger, dated as of January 2, 2018, by and among Dominion Energy, Sedona Corp. (a wholly-owned subsidiary of Dominion Energy) and SCANA
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NASDAQ	The NASDAQ Stock Market, Inc.
NAV	Net Asset Value
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NOL	Net Operating Loss
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
Nuclear Project	Project to construct Unit 2 and Unit 3 under the EPC Contract
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
Registrants	SCANA and SCE&G
Request	Request for Rate Relief filed by the ORS on September 26, 2017, as amended October 17, 2017
ROE	Return on Equity
RSA	Natural Gas Rate Stabilization Act
RTO/ISO	Regional Transmission Organization/Independent System Operator
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	SCANA Energy Marketing, Inc.
SCANA Services	SCANA Services, Inc.
SCE&G	South Carolina Electric & Gas Company
SCEUC	South Carolina Energy Users Committee
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SLED	South Carolina Law Enforcement Division
SO_2	Sulfur Dioxide
Southern Natural	Southern Natural Gas Company

Spirit Communications	SCTG, LLC and its wholly-owned subsidiary SCTG Communications, Inc.
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Tax Act	An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (previously known as The Tax Cuts and Jobs Act) enacted on December 22, 2017
Toshiba	Toshiba Corporation, parent company of WEC
Toshiba Settlement	Settlement Agreement dated as of July 27, 2017, by and among Toshiba, SCE&G and Santee Cooper
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
Unit 1	Nuclear Unit 1 at Summer Station
Unit 2	Nuclear Unit 2 at Summer Station (abandoned prior to construction completion)
Unit 3	Nuclear Unit 3 at Summer Station (abandoned prior to construction completion)
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
WEC	Westinghouse Electric Company LLC
WECTEC	WECTEC Global Project Services, Inc. (formerly known as Stone & Webster, Inc.), a wholly-owned subsidiary of WEC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

INVESTOR INFORMATION

SCANA's and SCE&G's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at *www.scana.com* (which is not intended as an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC) as soon as reasonably practicable after these reports are filed or furnished.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's Nuclear Project and other matters of interest to investors on SCANA's website. On SCANA's homepage, there is a yellow box containing links to the Nuclear and Other Investor Information sections of the website. The Nuclear section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor-related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the Nuclear Project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear and Other Investor Information yellow box.

CORPORATE STRUCTURE AND SEGMENTS OF BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees as of February 20, 2018 and 2017 of 5,228 and 5,910, respectively. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries, including the subsidiaries described below.

On January 2, 2018, SCANA entered into the Merger Agreement whereby it would become a wholly-owned subsidiary of Dominion Energy. The merger is subject to a variety of closing conditions including the receipt of approvals from several regulators and from SCANA's shareholders. Refer to Exhibit 2.01 in the Exhibit Index for information on where a copy of the Merger Agreement may be obtained. See also Note 10 to the consolidated financial statements for more discussion.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 719,000 customers and the purchase, sale and transportation of natural gas to approximately 368,000 customers (each as of December 31, 2017). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a unit power sales agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 563,000 residential, commercial and industrial customers (as of December 31, 2017). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food and beverage products, health services, automotive, chemicals, motorsports, non-woven textiles and electrical generation and construction.

Nonregulated Businesses

SCANA Energy markets natural gas in the southeast and provides energy-related services. A division of SCANA Energy sells natural gas to approximately 425,000 customers (as of December 31, 2017) in Georgia's deregulated natural gas market.

SCANA Services provides shared administrative and management services to SCANA's other subsidiaries.

For information with respect to major segments of business, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 12 of the consolidated financial statements. All such information is incorporated herein by reference.

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity by customer classification as percentages of electric revenues were as follows:

	Sales	
Customer Classification	**2017**	**2016**
Residential	45%	46%
Commercial	33%	33%
Industrial	18%	17%
Sales for resale	2%	2%
Other	2%	2%
Total	100%	100%

Sales for resale include sales to three municipalities in 2017 and 2016. Other includes short-term system sales which during 2017 included sales to two investor-owned utilities or registered marketers. Short-term system sales during 2016 included sales to four investor-owned utilities or registered marketers.

During 2017 SCE&G experienced a net increase of approximately 10,000 electric customers (growth rate of 1.4%), increasing its total electric customers to approximately 719,000 at year end.

The following projections assume normal weather where applicable. For the period 2017 to 2018, SCE&G projects a retail kWh sales increase of approximately 0.4% and customer growth of 1.5%. For the period 2018-2020, SCE&G projects total territorial kWh sales of electricity to increase 0.3% annually, total retail sales to decrease 0.2% annually, total electric customer base to increase 1.5% annually and territorial peak load (summer, in MW) to increase 1.0% annually. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%; however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a unit power sales agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system extends over a large part of the central, southern and southwestern portions of South Carolina. The system interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Santee Cooper, Georgia Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) were as follows:

	Cost of Fuel Used		
	2017	2016	2015
Per MMBTU:			
Nuclear	$ 0.95	$ 0.98	$ 0.95
Coal	3.31	3.41	3.81
Natural Gas	3.52	3.02	3.26
All Fuels (weighted average)	2.63	2.41	3.01
Per Ton: Coal	82.45	84.62	95.69
Per MCF: Gas	3.57	3.11	3.35

The sources and percentages of total MWh by each category of fuel for the preceding three years and estimates for the next three years follow:

	% of Total MWh Generated					
	Actual			Estimated		
	2015	2016	2017	2018	2019	2020
Coal	39%	37%	39%	38%	29%	30%
Nuclear	20%	25%	20%	20%	23%	20%
Hydro	3%	3%	2%	3%	3%	3%
Natural Gas & Oil	36%	33%	37%	35%	42%	41%
Biomass/Solar	2%	2%	2%	4%	3%	6%
Total	100%	100%	100%	100%	100%	100%

For a listing of the Company's generating facilities, see the Electric Properties section within Item 2. Properties.

In 2017, coal was primarily obtained through long-term contracts with suppliers located in eastern Kentucky, Tennessee, Virginia, and West Virginia. These contracts provide for approximately 2.1 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2019. Spot market purchases may occur when needed or when prices are believed to be favorable. The Company relies on unit trains and, in some cases, trucks for coal deliveries.

SCANA and SCE&G believe that electric operations comply with all applicable regulations relating to the discharge of SO_2 and NO_X. See additional discussion at Environmental Matters in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G, for itself and as agent for Santee Cooper, and WEC are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G supplies enriched products to WEC and WEC supplies nuclear fuel assemblies for Unit 1. WEC is SCE&G’s exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Unit 1 through 2033.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to allow for normal operations of its nuclear generating unit.

SCE&G stores spent nuclear fuel in its on-site spent-fuel pool, and has constructed a dry cask storage facility to accommodate the spent fuel output for the life of Unit 1. In addition, Unit 1 has sufficient on-site capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see the Environmental section of Note 10 to the consolidated financial statements.

SCE&G also uses long-term power purchase agreements to ensure that adequate power supply resources are in place to meet load obligations and reserve requirements. As of January 1, 2018, SCE&G had such agreements in place for 325 MW of capacity (expiring at various times through 2020). In addition, SCE&G had the ability to purchase an additional 204 MW of capacity under these agreements. On December 20, 2017, SCE&G entered into an agreement to purchase the Columbia Energy Center, which is the existing 540 MW combined cycle gas generating station to which these capacity contracts relate. Upon the closing of such purchase, these contracts will be moot, and all output of that station will be available for SCE&G's load obligations and reserve requirements. Also, as of December 31, 2017, SCE&G is taking delivery of utility scale solar generated power pursuant to 17 executed power purchase agreements totaling 218 MW-alternating current.

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GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported were as follows:

	SCANA		SCE&G	
Customer Classification	**2017**	**2016**	**2017**	**2016**
Residential	57.1%	57.9%	47.0%	48.3%
Commercial	26.5%	26.4%	27.8%	28.6%
Industrial	11.4%	10.4%	21.6%	19.5%
Transportation Gas	5.0%	5.3%	3.6%	3.6%
Total	100.0%	100.0%	100.0%	100.0%

For the period 2018-2020, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 31.7% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.5%, commercial of 0.9%, and industrial of 84.8%. Projections of total and industrial sales include amounts for new gas-fired electric generating plants that will be served by PSNC Energy.

For the period 2018-2020, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 2.2% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.4%, commercial of 1.0% and industrial of 2.9%.

For the period 2018-2020, each of SCANA's and SCE&G's total regulated natural gas customer base is projected to increase 2.6% annually. During 2017, SCANA recorded a net increase of approximately 24,000 regulated gas customers (growth rate of 2.6%), increasing the number of its regulated gas customers to approximately 931,000. Of this increase, SCE&G recorded a net increase of approximately 10,000 gas customers (growth rate of 2.9%), increasing the number of its total gas customers to approximately 368,000 (as of December 31, 2017).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost and Supply

SCE&G purchases natural gas under contracts with producers and marketers on both a short-term and long-term basis at market based prices. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2019), Transco (expiring at various times through 2084) and DECG (expiring at various times through 2036). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 212,194 MMBTU from Southern Natural, 110,458 MMBTU from Transco and 456,427 MMBTU from DECG. Additional natural gas volumes may be delivered to SCE&G's system as capacity is available through interruptible transportation.

The daily volume of gas that SCANA Energy is entitled to transport under its service agreements (expiring at various times through 2023) on a firm basis is 761,860 MMBTU. Additional natural gas volumes may be delivered as capacity is available through interruptible transportation.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $3.96 per MMBTU during 2017 and $3.46 per MMBTU during 2016.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G has 5,502,600 MMBTU of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 3,433,200 MMBTU of gas were in storage on December 31, 2017. SCE&G supplements its supplies of natural gas with two LNG storage facilities, one of which has liquefaction capability. Approximately 1,624,300 MMBTU (liquefied equivalent) of gas were in storage on December 31, 2017. For a discussion of SCE&G's natural gas storage capacity, see Item 2. Properties.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2031. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 710,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $4.39 per MMBTU during 2017 compared to $3.73 per MMBTU during 2016.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Energy Transmission, Inc., Columbia Gas Transmission, Transco and Enbridge Inc. provide for storage capacity of approximately 13,000,000 MMBTU. Approximately 9,000,000 MMBTU of gas were in storage under these agreements at December 31, 2017. PSNC Energy also maintains LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG which provides 1,300,000 MMBTU (liquefied equivalent) of storage space. Approximately 1,200,000 MMBTU (liquefied equivalent) were in storage under these agreements at December 31, 2017. Approximately 800,000 MMBTU (liquefied equivalent) of gas were in storage at PSNC Energy's LNG storage facility at December 31, 2017. For a discussion of PSNC Energy's LNG storage capacity, see Item 2. Properties.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SCANA Energy markets natural gas and provides energy-related services in the Southeast. In addition, a division of SCANA Energy markets natural gas to greater than 425,000 customers (as of December 31, 2017) in Georgia’s natural gas market. Georgia’s natural gas market includes approximately 1.6 million customers.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements.

REGULATION

Regulatory jurisdictions to which SCANA and its subsidiaries are subject are described in the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018. Were adverse developments to occur with respect to uncertainties highlighted elsewhere, the ability of SCE&G or GENCO to secure renewal of this short-term borrowing authority may be adversely impacted.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	License Expiration
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

* SCE&G operates the Saluda hydroelectric project under an annual license while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 2 to the consolidated financial statements.

Fuel Cost Recovery Procedures

The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions, and the cost of emission allowances used for SO_2, NO_X, mercury and particulates. In addition, the statutory definition of fuel cost allows electric utilities to recover avoided costs under the Public Utility Regulatory Policy Act of 1978, as well as costs incurred as a result of offering DER and net metering programs to its customers. SCE&G may request a formal proceeding concerning its fuel costs at any time.

Purchased gas cost recovery procedures related to the Company's natural gas operations along with related rate proceedings by the SCPSC and NCUC are described in Note 2 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of any new or pending regulations or standards upon existing operations cannot be predicted. For a discussion of how these regulations and standards may impact SCANA and SCE&G (including capital expenditures necessitated thereby), see the Environmental Matters section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements.

OTHER MATTERS

Insurance coverage for Unit 1 is described in Note 10 to the consolidated financial statements.

For a discussion of the impact of competition, see the Overview section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to the Company, and where indicated the risk factors also relate to Consolidated SCE&G.

The completion of the merger is subject to the receipt of consents, approvals and/or findings from governmental entities, which may impose conditions that could have an adverse effect on Dominion Energy or SCANA or could cause either Dominion Energy or SCANA to terminate the merger. The completion of the merger is also subject to there having not been certain substantive changes in certain South Carolina laws that have or would reasonably be expected to have an adverse effect on SCANA or its subsidiaries or changes in law that impose any condition that would reasonably be expected to result in specified changes to the Joint Petition. Additionally, any such changes in certain South Carolina law could affect the considerations which were relied upon by SCANA and/or Dominion Energy prior to the signing of the Merger Agreement.

Dominion Energy and SCANA are not required to complete the merger until after the requisite authorizations, approvals, consents and/or permits are received from the FERC, NRC, SCPSC, NCUC and GPSC. Any of the relevant governmental entities may oppose the merger, fail to approve the merger, fail to make required findings in favor of the merger, or impose certain requirements or obligations as conditions for their consent, approval or findings or in connection with their review. Regulatory approvals of the merger or findings with respect to the merger may not be obtained on a timely basis or at all, and such approvals or findings may include conditions that could have an adverse effect on the Company or Consolidated SCE&G, and/or result in the termination of the merger. The terms of any conditions imposed in order to obtain the requisite regulatory approvals or findings may not be known by the date of the special meeting of SCANA shareholders to vote on the merger proposal. No assurance can be given that the necessary approvals or findings will be obtained or that any required conditions will not have an adverse effect on Dominion Energy following the merger. If SCANA shareholders vote in favor of the merger proposal at the special meeting, Dominion Energy or SCANA may make decisions after the special meeting to waive a condition or approve certain actions required to obtain regulatory approvals or findings without seeking further approval of the SCANA shareholders.

Subject to the terms and conditions set forth in the Merger Agreement, the Merger Agreement requires Dominion Energy to accept conditions from regulators that could adversely impact Dominion Energy after the merger without either of Dominion Energy or SCANA having the right to refuse to close the merger on the basis of those regulatory conditions, except that Dominion Energy is generally not required, and SCANA is generally not permitted without Dominion Energy's prior approval, to take any action or accept any condition that results in a burdensome condition.

In addition, the Merger Agreement provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if, since the date of the Merger Agreement, any governmental entity shall have enacted any order, or there shall have been any change in law (including the BLRA and the other laws governing South Carolina public utilities), which imposes any material change to the terms, conditions or undertakings set forth in the Joint Petition, or any significant changes to the economic value of the Joint Petition, in each case as determined by Dominion Energy in good faith.

The Merger Agreement further provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if there shall have occurred any substantive change in the BLRA or other laws governing South Carolina public utilities which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries. There is currently pending before the South Carolina Senate a bill that would make substantive changes to the BLRA. This bill (H.4375) has passed the South Carolina House of Representatives. If this bill becomes law, Dominion Energy would not be obligated to complete the merger if it is determined that the bill has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries.

Certain lawsuits and regulatory actions have been filed against SCANA and SCE&G in connection with the abandonment of the Nuclear Project. If the relief requested in these matters (including a request for declaratory judgment that the BLRA is unconstitutional) is granted, Dominion Energy might not be obligated to complete the merger.

No assurance can be given that these risks will not materialize and either adversely impact Dominion Energy after the completion of the merger or, if such conditions rise to the thresholds discussed above, some of which, as described above, are in the subjective determination of Dominion Energy acting in good faith, or if the required authorizations, approvals, consents and/or permits are not obtained or received, result in the termination of the merger and adversely impact the results of operations, cash flows and financial conditions of the Company and Consolidated SCE&G.

Failure to complete the merger could negatively impact the stock price and the future business and financial results of SCANA.

If the merger is not completed, the ongoing business of the Company and Consolidated SCE&G may be adversely affected and the Company and Consolidated SCE&G could be subject to several risks, including the following:

- the price of SCANA common stock may decline to the extent that the current market price reflects an expectation by the market that the merger will be completed;
- obligations to pay certain costs relating to the merger, such as legal, accounting, financial advisory, filing, printing and mailing fees;
- the disruption of the Company's and Consolidated SCE&G's ongoing business or inconsistencies in its services, standards, controls, procedures and policies due to management's focus on the merger, any of which could adversely affect the ability of the Company and Consolidated SCE&G to maintain relationships with customers, regulators, vendors and employees, or could otherwise adversely affect the business and financial results of the Company or Consolidated SCE&G, without realizing any of the benefits of having the merger completed;
- the potential negative impact on the Company and Consolidated SCE&G ultimately resolving the rate and regulatory issues, including pending investigations and legal challenges, relating to the abandonment of the Nuclear Project in a manner satisfactory to SCANA on account of SCANA working with Dominion Energy to pursue the resolution of these issues as contemplated by the Merger Agreement rather than pursuing its regulatory and legal options for resolving these issues independently of considerations and obligations related to the merger; and
- the loss of other opportunities that could be beneficial to the Company and Consolidated SCE&G that could have been pursued during the pendency of the merger, without realizing any of the benefits of having the merger completed.

In addition to the above risks, SCANA may be required, under certain circumstances, to pay to Dominion Energy a termination fee of $240 million.

If the merger is not completed, no assurance can be given that these risks will not materialize and will not materially affect SCANA's business, financial results and stock price.

The Merger Agreement contains provisions that limit SCANA's ability to pursue alternatives to the merger, which could discourage a potential competing acquirer of SCANA or could result in any competing proposal being at a lower price than it might otherwise be.

The Merger Agreement contains provisions that, subject to certain exceptions, restrict SCANA's ability to initiate, solicit, knowingly encourage, facilitate or discuss competing third-party proposals to acquire all or a significant part of SCANA, or provide information to a third party that could reasonably be expected to lead to such a proposal. In addition, Dominion Energy generally has an opportunity to offer to modify the terms of the merger in response to any superior acquisition proposal that may be made before the SCANA board of directors is permitted to withdraw or qualify its recommendation. In some circumstances on termination of the Merger Agreement, SCANA may be required to pay to Dominion Energy a termination fee of $240 million.

These provisions, which the SCANA board regards as customary for transactions of this type, could discourage a potential competing acquirer that might have an interest in acquiring all or a significant part of SCANA from considering or proposing that acquisition, even if it were prepared to pay consideration with a higher per share cash or market value than the merger consideration, or might result in a potential competing acquirer proposing to pay a lower price than it might otherwise have proposed to pay because of the added expense of the termination fee that may become payable by SCANA in certain circumstances.

The pendency of the merger could adversely affect the business and operations of SCANA.

In connection with the pending merger, some current or prospective customers or vendors of SCANA's utilities may delay or defer decisions regarding their existing or proposed relationships with those utilities, which could negatively impact the operation, revenues, earnings, cash flows and expenses of the Company and Consolidated SCE&G, regardless of whether the merger is completed. Similarly, current and prospective employees of SCANA and its utilities may experience uncertainty about their future roles following the merger, which may adversely affect the ability of SCANA and its utilities to attract and retain key personnel during the pendency of the merger. In addition, due to operating covenants in the Merger Agreement, during the pendency of the merger, SCANA and its utilities may be unable to pursue strategic transactions, undertake significant capital projects, undertake certain significant financing or other specified transactions or pursue actions that are not in the ordinary course of business, even if such actions would prove beneficial.

Following the merger, Dominion Energy may be unable to successfully integrate the Company's and Consolidated SCE&G's businesses.

Dominion Energy and SCANA currently operate as independent public companies. After the merger, Dominion Energy will be required to devote significant management attention and resources to integrating the Company's and Consolidated SCE&G's business. Potential difficulties Dominion Energy may encounter in the integration process include the following:

- the complexities associated with integrating SCANA and its utility businesses, while at the same time continuing to provide consistent, high quality services;
- the complexities of integrating a company with different core services, markets and customers;
- the inability to attract and retain key employees;
- potential unknown liabilities and unforeseen increased expenses, delays or regulatory conditions associated with the merger;
- difficulties in managing political and regulatory conditions related to SCANA's utility business after the merger;
- the cost recovery plan includes a moratorium on filing requests for adjustments in SCANA's base electric rates until 2021 if the merger is approved by the SCPSC, which would limit Dominion Energy's ability to recover increases in non-fuel related costs of electric operations for SCE&G's customers; and
- performance shortfalls as a result of the diversion of Dominion Energy management's attention caused by completing the merger and integrating SCANA's utility businesses.

For these reasons, you should be aware that it is possible that the integration process following the merger could result in the distraction of Dominion Energy's management, the disruption of Dominion Energy's ongoing business or inconsistencies in its services, standards, controls, procedures and policies, any of which could adversely affect the ability of Dominion Energy to maintain or establish relationships with current and prospective customers, vendors and employees or could otherwise adversely affect the business and financial results of Dominion Energy.

Dominion Energy, the Company and Consolidated SCE&G may be adversely affected by negative publicity related to the merger and in connection with other related matters, including the abandonment of the Nuclear Project.

From time to time, political and public sentiment in connection with the merger and in connection with other matters, including the abandonment of the Nuclear Project, may result in a significant amount of adverse press coverage and other adverse public statements affecting Dominion Energy and the Company and Consolidated SCE&G. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceedings, as well as responding to and addressing adverse press coverage and other adverse public statements, can divert the time and effort of senior management from the management of Dominion Energy's, the Company's and Consolidated SCE&G's respective businesses.

Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of Dominion Energy, the Company and Consolidated SCE&G, on the morale and performance of their employees and on their relationships with their respective regulators, customers and commercial counterparties. It may also have a negative impact on their ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have an adverse effect on Dominion Energy's, the Company's and Consolidated SCE&G's respective business, financial condition, results of operations and prospects.

Pending litigation against SCANA and Dominion Energy could result in an injunction preventing the completion of the merger or may adversely affect the combined company's business, financial condition or results of operations following the merger.

Following the announcement of the merger, three lawsuits were filed asserting claims relating to the merger. First, an existing derivative lawsuit was amended to assert direct claims of a putative class of SCANA shareholders in the Court of Common Pleas of the County of Richland, South Carolina against the members of the SCANA board of directors, Dominion Energy and Sedona Corp., alleging breaches of various fiduciary duties by the members of the SCANA board of directors in connection with the merger and alleging that Dominion Energy and Sedona Corp. aided and abetted such alleged breaches.

Second, two putative class actions on behalf of SCANA shareholders have been filed in the Court of Common Pleas of the Counties of Lexington and Richland, South Carolina, respectively, against SCANA, the members of the SCANA board of directors, Dominion Energy and Sedona Corp., alleging breaches of various fiduciary duties by the members of the SCANA board of directors in connection with the merger and alleging that SCANA, Dominion Energy and Sedona Corp. aided and abetted such alleged breaches. Among other remedies, the plaintiffs in each case seek to enjoin the merger and rescind the Merger Agreement. In addition, the second and third lawsuits seek in the alternative, should the merger be completed, an award of unspecified monetary damages.

While the defendants believe that dismissal is warranted, the outcome of any such litigation is inherently uncertain. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger closes may adversely affect the combined company's business, financial condition or results of operation.

There is uncertainty as to whether the Company and Consolidated SCE&G will be able to recover costs expended for the Nuclear Project, and a reasonable return on those costs, under the abandonment provisions of the BLRA or through other means. As of December 31, 2017, the Company and Consolidated SCE&G have recognized a significant estimated impairment loss with respect to such investment and related costs. In the event the Company and Consolidated SCE&G were to determine that all or an additional portion of their remaining unrecovered Nuclear Project costs are to be disallowed and that significant additional impairment losses must be recognized, further material adverse impacts on their results of operations, cash flows and financial condition would occur.

During the term of the Interim Assessment Agreement, SCE&G and Santee Cooper evaluated the various elements of the Nuclear Project, including forecasted costs and completion dates, while construction continued, and SCE&G and Santee Cooper continued to make payments for such work. Based on this evaluation, and in light of Santee Cooper's decision to suspend construction, on July 31, 2017, the Company determined to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means. On July 31, 2017, SCE&G gave WEC a five-day notice of termination of the Interim Assessment Agreement, and notified WEC of its determination to stop construction of Unit 2 and Unit 3.

On August 1, 2017, SCE&G senior management provided an allowable ex parte briefing to the SCPSC regarding the Nuclear Project and this decision, and SCE&G also filed a petition with the SCPSC which included its plan of abandonment and certain proposed actions which would mitigate related customer rate increases, including a proposal to return to customers the net value of the proceeds received by SCE&G under or arising from the Toshiba Settlement.

The BLRA provides that, in the event of abandonment prior to plant completion, costs incurred, including AFC, and a return on those costs may be recoverable through rates, if the SCPSC determines that the decision to abandon the Nuclear Project was prudent. Through its August 1, 2017 petition, SCE&G had sought recovery of such costs expended on the construction of the project, including certain costs incurred subsequent to SCE&G's last revised rates update, and a reasonable return on those costs, and certain other costs under the abandonment provisions of the BLRA. Subsequently, SCE&G's management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow for adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew its August 1, 2017 petition from the SCPSC on August 15, 2017.

In August 2017, special committees of the South Carolina General Assembly, both in the House of Representatives and in the Senate, began conducting public hearings regarding the decision to abandon the Nuclear Project. Members of SCE&G's senior management, along with representatives from Santee Cooper, the ORS and other interested parties, testified before these committees. Several legislative proposals adverse to the Company and Consolidated SCE&G resulted from the work of these committees and are being considered by the General Assembly in 2018. In January 2018, these committees reconvened for the purpose of considering the effects of the proposed merger. On January 31, 2018, the House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law, the precise impact of any change in the law, or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

In September 2017, the Company was served with a subpoena issued by the United States Attorney's Office for the District of South Carolina seeking documents relating to the Nuclear Project. The subpoena requires the Company to produce a broad range of documents related to the project. Also in September 2017, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. In October 2017, the staff of the SEC's Division of Enforcement also issued a subpoena for documents related to an investigation they are conducting related to the Nuclear Project. The Company and Consolidated SCE&G intend to fully cooperate with these investigations. No assurance can be given as to the timing or outcome of these matters.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections. SCE&G estimates that revised rates collections currently total approximately $445 million annually, and the amounts accumulated as of December 31, 2017 total approximately $1.9 billion.

On September 27, 2017, the scheduled payments under the Toshiba Settlement, exclusive of the payment due in October 2017, were purchased by Citibank for a one-time upfront payment of $1.847 billion (approximately $1.016 billion for SCE&G's 55% share), including amounts related to certain liens that SCE&G was contesting but for which SCE&G may ultimately have been liable. The initial payment was then received from Toshiba on October 2, 2017, as scheduled, in the amount of $150 million ($82.5 million for SCE&G's 55% share). A regulatory liability has been recorded on the consolidated balance sheets to reflect the amount related to the Toshiba Settlement that will be utilized to benefit SCE&G's customers in a manner to be determined by the SCPSC. While this determination is pending, SCE&G has utilized portions of the proceeds to repay maturing commercial paper balances, which short-term borrowings had been incurred primarily for the construction of Unit 2 and Unit 3 prior to the decision to stop their construction. On October 17, 2017, the ORS filed a motion with the SCPSC to amend its earlier Request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. It is possible that the outcome of regulatory or legal proceedings could result in requiring SCE&G's share of these proceeds to be placed in escrow pending their final disposition, or could require these proceeds to be refunded to customers in the near-term or otherwise make these funds unavailable to SCE&G. If any of these circumstances were to arise, it is anticipated that SCE&G would reissue commercial paper or draw on its credit facilities to fund such requirement. However, such sources may not be available. Any such requirement would significantly harm the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition. In addition, the purchase agreement with Citibank provides that SCE&G and Santee Cooper (each according to its pro rata share) would indemnify Citibank for its losses arising from misrepresentations or covenant defaults under the purchase agreement.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. Parties who filed to intervene in the matter or who filed a letter in support of the request by the ORS include the Governor, the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, the SCEUC, certain large industrial customers, and several environmental groups. After conducting a hearing to consider SCE&G's motion, the SCPSC denied the motion on December 20, 2017 and ordered that a hearing be scheduled to consider the Request. The hearing has not yet been scheduled. SCE&G intends to continue vigorously contesting the Request, but cannot give any assurance as to the timing or outcome of this matter. Any adverse action by the SCPSC, such as that sought by the ORS in the Request, could have a material adverse impact on the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

In the third quarter of 2017, SCE&G recorded a pre-tax impairment loss of $210 million related to unrecovered nuclear project costs. In the fourth quarter of 2017, SCE&G recorded an additional pre-tax impairment loss of $908 million related to such unrecovered costs and other related costs. See Note 10 to the consolidated financial statements. These impairment losses have had the effect of increasing the Company's and Consolidated SCE&G's debt to total capitalization. If the SCPSC were to rule in favor of the ORS in response to the Request that SCE&G suspend collections from customers of amounts previously authorized under the BLRA, or were other actions of the SCPSC or others taken in order to significantly restrict SCE&G’s access to revenues or impose additional adverse refund obligations on SCE&G, the Company’s and Consolidated SCE&G's assessments regarding the recoverability of all or a portion of the remaining balance of unrecovered Nuclear Project costs would be adversely impacted. Also, the recognition of significant additional impairment losses with respect to unrecovered Nuclear Project costs could further increase the Company’s and Consolidated SCE&G’s debt to total capitalization to a level which may limit their ability to borrow under their commercial paper programs or under their credit facilities and also could constitute a default under these credit facilities. Borrowing costs for long-term debt issuances and access to capital markets could also be negatively impacted.

The ability of SCE&G to recover its costs related to the construction and subsequent abandonment of the Nuclear Project, and a reasonable return on them, through rates will be subject to review and approval by the SCPSC. An application under the abandonment provisions of the BLRA, and the regulatory process contemplated thereby, have never been pursued or legally challenged. As a result, and in light of the contentious nature of the ongoing reviews by and related activities of the South Carolina House Utility Ratepayer Protection Committee, the South Carolina Senate's V.C. Summer Nuclear Project Review Committee and others, and given pending legislation, it is uncertain whether SCE&G will be able to successfully recover the costs of the abandoned units, and a reasonable return on them. Under the BLRA, the SCPSC must consider and rule on a petition within six months. Even so, and although expedited action has been requested by SCE&G, it is unclear when the SCPSC will consider the Joint Petition. In any case, anticipated appeals of any ruling by the SCPSC could be protracted. Further, should the regulatory construct in South Carolina change in such a manner that recovery is sought through other legal proceedings or through regulatory proceedings outside the provisions of the BLRA, such as in a general rate case, other uncertainties may arise, such as those highlighted with respect to the Merger Agreement.

Further downgrades in the credit ratings of SCANA or any of SCANA’s subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies currently rate SCE&G’s senior secured debt and the senior unsecured debt of PSNC Energy as investment grade. One rating agency currently rates SCANA’s senior unsecured debt as investment grade, and two rating agencies rate SCANA's senior unsecured debt as below investment grade. In addition, rating agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies’ credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements.

In the first quarter of 2017, the rating agencies placed SCANA and SCE&G’s credit ratings on negative outlook or watch status due to adverse developments relating to the WEC bankruptcy. In the third quarter of 2017, two agencies lowered their ratings for SCANA and its rated subsidiaries, citing a decline in the regulatory environment as a principal reason for the downgrades, and both agencies maintained their negative outlook or watch status. On January 3, 2018, after SCANA announced a proposed merger with Dominion Energy, each of the three agencies affirmed or reported no change to their respective credit ratings, and one agency revised its rating outlook for SCANA and its rated operating companies from negative to evolving. However, on January 31, 2018, the South Carolina House of Representatives overwhelmingly approved a bill (H. 4375) that, if enacted, would temporarily repeal rates SCE&G collects under the BLRA. As a result, on February 5, 2018, one agency downgraded its ratings for SCANA and SCE&G, and attributed the downgrade to the action taken by the House of Representatives and the politically charged environment that is expected to weigh heavily on any decisions by the SCPSC related to SCE&G's electric rates. All of the ratings for SCANA, SCE&G and PSNC Energy are either under review for possible downgrade or have a negative or evolving outlook.

Any actions taken by or anticipated to be taken by regulators or legislators that are viewed as adverse, including a change to the BLRA or a requirement that SCE&G make credits to future bills or refunds to customers above such amounts as are included in the Merger Agreement or any requirement that SCE&G make such credits or refunds in the absence of the merger being consummated, or deterioration of our rated companies’ commonly monitored financial credit metrics and additional adverse developments with respect to the Nuclear Project, could further negatively affect their debt ratings. If these rating agencies were to further lower any of these ratings, borrowing costs on new issuances of long-term debt and commercial paper would increase, which could adversely impact financial results or limit or eliminate refinancing opportunities, and the potential pool of investors and funding sources could decrease. Any further lowering of these ratings could also trigger higher interest costs as well as more stringent collateral requirements on interest rate and commodity hedges and under gas supply agreements and a reduction in the availability of suppliers.

The Company and Consolidated SCE&G are defendants in numerous legal proceedings and the subject of ongoing governmental investigations, examinations and other inquiries stemming from the decision to abandon the Nuclear Project. The outcome of each of these matters is uncertain, and any resolution adverse to the Company and Consolidated SCE&G could adversely affect results of operations, cash flows and financial condition.

Following the Company's decision to abandon construction of Unit 2 and Unit 3, putative derivative and class action lawsuits seeking have been filed in multiple state circuit courts and federal district court on behalf of customers, shareholders and SCANA (in the case of the derivative shareholder actions), against SCANA, SCE&G, or both, and in certain cases some of their officers and/or directors. The plaintiffs allege various causes of action, including but not limited to waste, breach of fiduciary duty, negligence, unfair trade practices, unjust enrichment, conspiracy, fraud, constructive fraud, misrepresentation and negligent misrepresentation, promissory estoppel, constructive trust, and money had and received, among other causes of action. Plaintiffs generally seek compensatory, consequential and statutory treble damages and such further relief as the court deems just and proper. In addition, certain plaintiffs seek a declaration that SCE&G may not charge its customers to reimburse itself for past and continuing costs of the Nuclear Project. Certain plaintiffs also seek to freeze or appoint a receiver for certain of SCE&G's assets, namely all money SCE&G has received under the Toshiba payment guaranty and related settlement agreement for the Nuclear Project.

In addition, purported class action lawsuits have been filed on behalf of investors in federal court against SCANA and certain of its current and former executive officers and directors. The plaintiffs allege, among other things, that defendants violated Section 10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and two suits allege violations of the Racketeer Influenced and Corrupt Organizations Act. In one suit, the plaintiff alleges that director defendants violated Section 14(a) of the Exchange Act and SEC Rule 14a-9 by allowing or causing misleading proxy statements to be issued. The plaintiffs in each of these suits seek compensatory and consequential damages and such further relief as the court deems proper.

A complaint has been filed by Fairfield County against SCE&G making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of the implied duty of good faith and fair dealing, and unfair trade practices related to SCE&G's termination of the FILOT agreement. Plaintiff seeks injunctive relief to prevent SCE&G from terminating the FILOT agreement; actual and consequential damages; treble damages; punitive damages; and attorneys' fees.

The Company has also been served with subpoenas issued by the United States Attorney's Office for the District of South Carolina and the staff of the SEC's Division of Enforcement seeking documents relating to the Nuclear Project. In addition, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee have requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. The Company and Consolidated SCE&G intend to fully cooperate with any such investigations. Also in connection with the abandonment of the Nuclear Project, various state or local governmental authorities have challenged or may attempt to challenge, reverse or revoke one or more previously-approved tax or economic development incentives, benefits or exemptions, including use tax exemptions, and are attempting to apply such action retroactively.

The Company and Consolidated SCE&G cannot predict the outcome of these matters or other claims, allegations or assessments which may arise, and it is possible that adverse outcomes from some of these matters would not be covered by insurance. A resolution adverse to the Company and Consolidated SCE&G could adversely affect results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G are engaged in activities for which they have claimed, and expect to claim in the future, research and experimentation tax deductions and credits and tax abandonment losses, all of which are the subject of uncertainty and which may be considered controversial by the taxing authorities. The outcome of those uncertainties could adversely impact cash flows, results of operations and financial condition.

The Company and Consolidated SCE&G have claimed significant research and experimentation tax deductions and credits related to the design and construction activities of Unit 2 and Unit 3. A significant portion of these claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. (See also Note 5 to the consolidated financial statements.) The Company and Consolidated SCE&G also expect to claim a significant tax deduction related to the decision to stop construction and to abandon the Nuclear Project in 2017.

These tax claims primarily involve the timing of recognition of tax deductions rather than permanent tax attributes, and their permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to them, had been deferred within regulatory assets. As such, until December 31, 2017 when it was determined to treat these deferrals as impaired (see Note 10 to the consolidated financial statements), these claims had not had, and were not expected to have in the future, significant direct effects on the Company's and Consolidated SCE&G's results of operations. Nonetheless, the claims have contributed significantly to the Company's and Consolidated SCE&G's cash flows by providing a significant source of capital and lessening the level of debt and equity financing that the Company and Consolidated SCE&G have needed to raise in the financial markets.

The claims made to date are under examination and are considered controversial by the IRS. Tax deductions which are expected to be claimed in connection with the determination to abandon the construction of Unit 2 and Unit 3 may also be considered controversial; therefore, it is also expected that the IRS will examine future tax returns. To the extent that any of these claims are not sustained as ordinary losses on examination or through any subsequent appeal, the Company and Consolidated SCE&G will be required to repay any cash received for tax benefit claims which are ultimately disallowed, along with interest on those amounts. Such amounts could be significant and could adversely affect the Company's and Consolidated SCE&G's liquidity, cash flows, results of operations and financial condition. In certain circumstances, which management considers to be remote, penalties for underpayment of income taxes could also be assessed. Additionally, in such circumstances, the Company and Consolidated SCE&G may need to access the capital markets to fund those tax and interest payments, which could in turn adversely impact their ability to access capital markets for other purposes.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing NO_X, SO_2, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. No new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. On October 10, 2017, the Administrator of the EPA signed a notice proposing to repeal the rule on the grounds that it exceeds the EPA's statutory authority. The EPA is further considering the scope of any potential replacement rule and plans to formally solicit information on systems of emission reduction that are in accord with the EPA's interpretation of its statutory authority. However, a number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none has yet been enacted. In April 2012, the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. The EPA's rule for cooling water intake structures to meet the best technology available became effective in October 2014, and the EPA also issued a final rule in December 2014 regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA finalized new standards under the CWA governing effluent limitation guidelines for electric generating units in September 2015. The rule setting forth these new standards has been stayed administratively, and the EPA has begun a new rulemaking process that could take until 2020 before revisions to the effluent limitation guidelines for electric generating units is complete.

Compliance with these environmental laws and regulations requires us to commit significant resources toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements, additional regulations and related costs, or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as more stringent clean-up of contaminated sites or reduced emission allowances) or require us to incur additional expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our businesses and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed. Additionally, there can be no assurance that a federal tax or fee for carbon emitting generating facilities will not be imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. Such renewable energy may not be readily available in our service territories and could be costly to build, finance, acquire, integrate, and/or operate. Resulting increases in the price of electricity to recover the cost of these types of generation, and the costs of their integration to the electric system, could result in lower usage of electricity by our customers. In addition, DER generation at customers' facilities could result in the loss of sales to those customers. Compliance with potential future portfolio standards could significantly impact our capital expenditures and our results of operations and financial condition. Utility scale solar development companies are currently working in South Carolina to develop projects in SCE&G's service territory. The integration of those resources at high penetration levels may be challenging.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In turn, they affect the costs and rates of the Company and Consolidated SCE&G. In effecting compliance with MATS, SCE&G has retired three of its oldest and smallest coal-fired units and converted three others such that they are gas-fired.

Commodity price changes, delays in delivery of commodities, commodity availability and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs), availability and deliverability. Any such changes could affect the prices these businesses charge, their operating costs, and the competitive position of their products and services. In addition, the abandonment of the Nuclear Project may heighten the Company's and Consolidated SCE&G's future exposure to volatility in prices of non-nuclear commodities such as natural gas. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to result in the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial condition.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternate forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers on a volumetric rate structure unable to switch to alternate fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G. A regulatory mechanism applies to residential and commercial customers at PSNC Energy to mitigate the earnings impact of an increase or decrease in gas usage.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, the Department of Homeland Security, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental agencies, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our businesses. In addition to many other aspects of our businesses, these requirements impact the services mandated or offered to our customers, and the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the pricing of utility services, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. Non-compliance with these requirements by third parties, such as our contractors, vendors and agents, may subject the Company and Consolidated SCE&G to operational risks and to liability. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's or Consolidated SCE&G's businesses. Non-compliance with these laws and regulations could result in fines, litigation, loss of licenses or permits, mandated capital expenditures and other adverse business outcomes, as well as reputational damage, which could adversely affect the cash flows, results of operations, and financial condition of the Company and Consolidated SCE&G.

Furthermore, changes in or uncertainty in monetary, fiscal, tax, economic, trade, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G also could be adversely impacted by changes in tax policy, or taxes related to the usage of certain fuel types in our businesses or our ownership and/or operation of certain types of generating facilities. Future, unknown regulation of hydraulic fracturing activities also could impact the operations and finances of the Company and Consolidated SCE&G.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects (including the abandonment of Unit 2 and Unit 3 as previously described), results of DSM Programs, results of DER programs, and/or increases in operating costs may lead to requests for regulatory relief and any related administrative or legislative action, decision, regulation or law affecting rates, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits. Additionally, in 2017, several legislative proposals were introduced that are being or are expected to be considered by the South Carolina General Assembly in 2018. In the event certain provisions of these legislative proposals were to become law as proposed, such provisions could adversely impact SCE&G's rate recovery with respect to the Nuclear Project. Furthermore, there can be no assurance that other legislation which might modify or repeal the BLRA in a manner which would adversely impact SCE&G's rate recovery, including its reasonable return on costs, with respect to its abandonment of Unit 2 and Unit 3 will not be proposed and passed. Any such action could also result in a failure to consummate the merger.

SCE&G's electric operations in South Carolina and the Company's gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the ability of SCE&G to recover the cost of the Nuclear Project, including abandonment costs, and a reasonable return on those costs, is subject to rate regulation by the SCPSC. Consolidated SCE&G's generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. SCE&G's electric transmission system is subject to extensive regulations and oversight from the SCPSC, NERC and FERC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as market conditions evolve.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement, many of which are still pending final action by those federal agencies. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers and major swap participants, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers or major swap participants, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Our ability to charge customer rates that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards related to compliance with laws and regulations, ethical conduct, operational effectiveness, customer service and the safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company's and Consolidated SCE&G's access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to assure reliability of provided services, to focus on the safety of employees, customers and the public, to ensure environmental compliance, to maintain the physical and cyber security of their operations and assets, to maintain the privacy of information related to our customers and employees, and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. Traditional news media and social media can very rapidly convey information, whether factual or not, to large numbers of people, including customers, investors, regulators, legislators and other stakeholders, and the failure to effectively manage timely, accurate communication through these channels could adversely impact our reputation. The Company and Consolidated SCE&G also are committed to operational excellence, to quality customer service, and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments, or a perceived failure to meet these commitments, may subject the Company and Consolidated SCE&G not only to fraud, regulatory action, litigation or financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

A failure of the Company and Consolidated SCE&G to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows.

The Company and Consolidated SCE&G depend on maintaining the physical and cyber security of their operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our businesses could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's and Consolidated SCE&G's operations are dependent in some manner upon our cyber systems, which encompass electric and gas operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company and Consolidated SCE&G, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, vendor, shareholder, employee, or corporate information. The Company and Consolidated SCE&G may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to mitigate the adverse impacts of these events. As a result, the Company's and Consolidated SCE&G's financial condition, results of operations, and cash flows may be adversely affected.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and we may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company's and Consolidated SCE&G's business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company's and Consolidated SCE&G's ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA's pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition, including its shareholders' equity.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and, in deregulated markets, received lower prices for natural gas when weather conditions have been milder than normal, and as a consequence earned less income from those operations. Mild weather in the future could adversely impact the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as hurricanes or other significant weather events, electromagnetic events, the 2011 earthquake and tsunami in Japan or fires) or man-made mishaps (such as natural gas transmission pipeline failure, electric utility companies' ash pond failures, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial condition, operating expenses, and cash flows.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction and environmental compliance, are significant, and these projects are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of these projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in electric generation and in other internal infrastructure projects, including projects for environmental compliance. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and construction schedules may be affected by many variables, such as the regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness and/or financial stability, unforeseen difficulties meeting critical regulatory requirements, contract disputes and litigation, and changes in key contractors or subcontractors. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, adverse changes in applicable laws and regulations, new or enhanced environmental or regulatory requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. To the extent that, in connection with the construction of a project, delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete the project, our results of operations, cash flows and financial condition, as well as our qualifications for applicable governmental programs, benefits and tax credits may be adversely affected.

A significant portion of Consolidated SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition.

SCE&G jointly owns and is the operator of Unit 1. Various risks of nuclear generation to which SCE&G is subject include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;

- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and suppliers thereof, fabrication of nuclear fuel and related vendors, and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate;
- Uncertainties with respect to possible future increased regulation of nuclear facilities and nuclear generation, and related costs thereof; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In today's environment, there is a heightened risk of terrorist attack on the nation's nuclear facilities, which has resulted in increased security costs at our nuclear plant. Although we have no reason to anticipate a serious nuclear incident, a major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit, resulting in costly changes to units in operation and adversely impacting our results of operations, cash flows and financial condition. Furthermore, a major incident at a domestic nuclear facility could result in retrospective premium assessments under our nuclear insurance coverages.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via an RTO/ISO is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should an RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina or North Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets could be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems, which systems have undergone a rapid decline in their costs. As a result of federal and state subsidies, potential regulations allowing third-party retail sales, and advances in distributed generation technology, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and will slow growth, potentially causing higher rates to customers.

The Company and Consolidated SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and Consolidated SCE&G, which may be affected by regional, national or even international economic factors. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in higher costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. Also, in connection with the pending merger, some customers or vendors of the Company and Consolidated SCE&G may delay or defer decisions, which could negatively impact the revenues, earnings, cash flows and expenses of the Company and Consolidated SCE&G regardless of whether the merger is completed. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally, legislative actions (including tax reform), or regulatory actions. Industrial and commercial customer growth also potentially is affected by the availability of "clean" energy options in our service territory. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns. For instance, improvements in energy storage technology, if realized, could have dramatic impacts on the viability of and growth in distributed generation.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms that are attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be adversely impacted.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission equipment failure, information systems failure or security breach, operator error, natural disasters, and the effects of a pandemic, terrorist attack or cyber attack on our workforce or facilities or on vendors and suppliers necessary to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The integration of a significant amount of distributed generation into our systems may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a natural gas line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's and Consolidated SCE&G's revenues, results of operations, cash flows, and financial condition. Insurance may not be available or adequate to mitigate the adverse impacts of these events.

SCANA's ability to pay dividends and to make payments on SCANA's debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital.

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SCANA Energy, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Further, SCANA has agreed to obtain the consent of Dominion Energy, which consent cannot be unreasonably withheld, prior to making dividend payments to shareholders greater than $0.6125 per share for any quarter while the Merger Agreement is pending. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e., natural gas) market risk. We could be required to provide cash collateral or recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract. We could also be required to provide additional cash collateral if credit rating agency downgrades of our debt trigger more stringent requirements.

The Company strives to manage commodity price exposure by establishing risk limits and utilizing various financial instruments (exchange traded and over-the-counter instruments) to hedge physical obligations and reduce price volatility. We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be adversely impacted.

Failure to retain and attract key personnel could adversely affect the Company's and Consolidated SCE&G's operations and financial performance, particularly in light of uncertainties related to and resulting from abandonment of the Nuclear Project and the pending merger.

A significant portion of our workforce will be eligible for retirement during the next few years. Uncertainties related to regulatory, legislative and legal proceedings, as well as the proposed merger, also weigh significantly on the employment considerations made by current and prospective employees. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our businesses. Competition for these employees is high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. Further, the Company's or Consolidated SCE&G's ability to construct or maintain generation or other assets requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance. Furthermore, increased medical benefit costs of employees and retirees could adversely affect the results of operations of the Company and Consolidated SCE&G. Medical costs in this country have risen significantly over the past number of years and are expected to continue to increase at unpredictable rates. Such increases, unless satisfactorily managed by the Company and Consolidated SCE&G, could adversely affect results of operations.

***The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial condition, and access to capital*.**

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes, including customers' concerns regarding rate increases, such as the current environment relating to proposed recovery of costs, and a reasonable return on those costs, under the abandonment provisions of the BLRA or through other means, may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously supported by legislation or approved by regulators), to the detriment of the Company or Consolidated SCE&G (e.g., revision or repeal of the BLRA). In addition, operating covenants in the Merger Agreement require the consent of Dominion Energy prior to SCANA taking certain actions, which consent cannot be unreasonably withheld, during the pendency of the merger. As a result, the Company and Consolidated SCE&G may be unable to pursue strategic transactions, undertake significant capital projects, undertake certain significant financing or other specified transactions or pursue actions that are not in the ordinary course of business even if such actions would prove beneficial. Further, the Company's and Consolidated SCE&G's management may be focused on completion of the merger, which could lead to the disruption of ongoing business or inconsistencies in service, standards, controls, procedures and policies, any of which could adversely affect the ability of the Company and Consolidated SCE&G to maintain relationships with customers, regulators, vendors and employees, or could otherwise adversely affect their business and financial results, without realizing any of the benefits of having the merger completed. Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company's or Consolidated SCE&G's interests, may have a negative effect on our results of operations, cash flows and financial condition, as well as limit our ability to access capital.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds directly all of the capital stock of each of its subsidiaries.

SCE&G's bond indenture, which secures its First Mortgage Bonds, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

Electric Properties

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2017.

	In-Service Date	Net Generating Capacity Summer (MW)
Coal-Fired Steam:		
Wateree - Eastover, SC	1970	684
Williams - Goose Creek, SC	1973	605
Cope - Cope, SC	1996	415
Kapstone - Charleston, SC	1999	85
Gas-Fired Steam:		
McMeekin - Irmo, SC	1958	250
Urquhart Unit 3 - Beech Island, SC	1953	95
Nuclear:		
Summer Station Unit 1 - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647
Internal Combustion Turbines:		
Jasper Combined Cycle - Jasper, SC	2004	852
Urquhart Combined Cycle - Beech Island, SC	2002	458
Peaking units - various locations in SC	1968-2010	348
Hydro:		
Fairfield Pumped Storage - Parr, SC	1978	576
Saluda - Irmo, SC	1930	200
Other - various locations in or bordering SC	1905-1914	18

SCE&G owns 436 substations having an aggregate transformer capacity of 32.1 million Kilovolt ampere. The transmission system consists of 3,469 miles of lines, and the distribution system consists of 18,559 pole miles of overhead lines and 7,622 trench miles of underground lines.

Natural Gas Distribution and Transmission Properties

SCE&G's natural gas system includes 447 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and DECG. SCE&G’s distribution system consists of 17,671 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6,180 MMBTU per day and store the liquefied equivalent of 1,009,400 MMBTU of natural gas. The Salley facility can store the liquefied equivalent of 927,000 MMBTU of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 61,800 MMBTU per day at Charleston and 92,700 MMBTU per day at Salley.

PSNC Energy’s natural gas system consists of 607 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy’s distribution system consists of 22,141 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000,000 MMBTU, the capacity to liquefy up to 4,000 MMBTU per day and the capacity to regasify approximately 100,000 MMBTU per day.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G:

The following describes certain legal proceedings through December 31, 2017. The Company and Consolidated SCE&G intend to vigorously contest the lawsuits which have been filed against them. For developments related to these or other proceedings subsequent to December 31, 2017, see Note 2 and Note 10 to the consolidated financial statements. No reference to, or disclosure of, any proceeding, item or matter described below shall be construed as an admission or indication that such proceeding, item or matter is material or that such proceeding, items or matter is required to be referred to or disclosed in this Form 10-K.

Ratepayer Class Actions

On August 11, 2017, a purported class action was filed against SCE&G by plaintiff LeBrian Cleckley (the "Cleckley Lawsuit"), on behalf of himself and all others similarly situated, in the State Court of Common Pleas in Richland County, South Carolina (the "Richland County Court"). The plaintiff alleges, among other things, that SCE&G was negligent and unjustly enriched and breached alleged fiduciary and contractual duties by failing to properly manage the Nuclear project. The plaintiff seeks to recover, on behalf of the purported class, unspecified damages and attorneys' fees, specific performance of the alleged implied contract to construct the now abandoned project, and any other relief the court deems proper. At December 31, 2017, SCE&G's amended motion to dismiss was scheduled to be heard on January 8, 2018. Also at December 31, 2017, the following additional motions were pending: SCE&G's Motion for Protective Order, filed October 2, 2017; Plaintiff's Motion to Compel Discovery, filed October 20, 2017; and Plaintiff's Motion to Appoint a Receiver, filed November 1, 2017. By order dated October 31, 2017, the South Carolina Supreme Court consolidated all pending state court ratepayer class actions and assigned the consolidated cases to a single Circuit Court judge.

On August 14, 2017, a purported class action was filed against SCE&G by plaintiff Richard Lightsey (the "Lightsey Lawsuit"), on behalf of himself and all others similarly situated, in the State Court of Common Pleas in Hampton County (the "Hampton County Court"). The plaintiff makes substantially similar allegations as those alleged in the Cleckley Lawsuit and, in addition, alleges that SCE&G committed unfair trade practices and violated state anti-trust laws. The plaintiff seeks a declaratory judgment that SCE&G may not charge its customers for any past or continuing costs of the Nuclear Project. The plaintiff also seeks compensatory, punitive and statutory treble damages, attorneys' fees, and any other relief the court deems proper. On August 25, 2017, SCE&G filed a motion to transfer venue to Lexington County, South Carolina. At December 31, 2017, the following motions were pending: Plaintiff's Motion for Class Certification, filed August 23, 2017; SCE&G's Motion to Dismiss, etc., filed September 14, 2017; SCE&G's Motion for Protective Order, filed September 26, 2017; Plaintiff's Motion to Compel, filed October 12, 2017; and SCE&G's Motion to Dismiss, etc., Second Amended Complaint, filed October 24, 2017.

On August 28, 2017, a purported class action was filed against SCANA and SCE&G by plaintiff Edwinda Goodman, on behalf of herself and all others similarly situated, in the State Court of Common Pleas in Fairfield County (the "Fairfield County Court"). The plaintiff makes substantially similar allegations as those alleged in the Cleckley Lawsuit and, in addition, alleges that SCE&G committed fraud and misrepresentation in failing to properly manage the Nuclear Project. The plaintiff seeks to have the defendants' assets frozen and all monies recovered from Toshiba and other sources be placed in a constructive trust for the benefit of ratepayers. The plaintiff also seeks compensatory, punitive and treble damages, attorneys' fees, and any other relief the court deems proper. At December 31, 2017, the following motions were pending: SCE&G's Motion to Dismiss and Strike, filed October 2, 2017; SCE&G's Motion for Protective Order, filed October 2, 2017; and Plaintiff's Motion to Appoint Receiver and Expedite Hearing, served November 2, 2017.

On September 7, 2017, a purported class action was filed against Santee Cooper, SCE&G, Palmetto Electric Cooperative, Inc. and Central Electric Power Cooperative, Inc. by plaintiff Jessica Cook, on behalf of herself and all others similarly situated, in the Hampton County Court. The plaintiff makes substantially similar allegations as the Cleckley Lawsuit and the Lightsey Lawsuit. The plaintiff seeks a declaratory judgment that defendants may not charge the purported class for reimbursement for past or future costs of the Nuclear Project, as well as other compensatory and statutory treble damages, attorneys' fees, and any other relief the court deems proper. At December 31, 2017, the following motions were pending: SCE&G's Motion to Dismiss and to Strike, filed October 11, 2017; SCE&G's Motion for Protective Order, filed October 11, 2017; Santee Cooper's Motion to Dismiss Third Amended Complaint, filed October 24, 2017; Plaintiff's Motion for Default Judgment against Central Electric Power Cooperative, filed November 1, 2017; and Central Electric Power Cooperative, Inc.'s Motion to Dismiss Third Amended Complaint, filed November 16, 2017.

Also on September 7, 2017, a purported class action was filed against Santee Cooper and SCANA by plaintiffs Hope Brown and Thomas Lott, on behalf of themselves and all others similarly situated, in the Richland County Court. The plaintiffs allege, among other things, that SCE&G conspired with Santee Cooper to unlawfully deprive plaintiffs of their property rights guaranteed under the United States and South Carolina Constitutions and were unjustly enriched by the Nuclear Project. The plaintiffs seek disgorgement of all monies spent by defendants on the project, as well as other compensatory and punitive damages, attorneys' fees, and any other relief the court deems proper. Plaintiffs' counsel voluntarily dismissed this action without prejudice on November 12, 2017.

On September 25, 2017, a purported class action was filed against SCANA by plaintiff Christine Delmater, on behalf of herself and all others similarly situated, in the District Court. The plaintiff alleges, among other things, that SCE&G violated provisions of the Racketeer Influenced and Corrupt Organizations Act 18 U.S.C. §1961, was negligent, breached alleged contractual duties, and was unjustly enriched by failing to properly manage the Nuclear Project. The plaintiff seeks compensatory and consequential damages, and any other relief the court deems proper. Plaintiff filed its Second Amended Complaint on November 7, 2017, and filed a Motion for Injunctive Relief on November 8, 2017. Following extensions, responsive pleadings to the Second Amended Complaint and the Motion for Injunctive Relief were filed December 21, 2017.

On October 9, 2017, plaintiffs Chris Kolbe and Ruth Ann Keffer filed an amended complaint in a purported class action, on behalf of themselves and all others similarly situated, against Santee Cooper and certain of its directors and officers, in the Berkeley County Court of Common Pleas, naming SCE&G and SCANA as additional defendants. The plaintiffs allege, among other things, that SCE&G and SCANA were grossly negligent, reckless, breached contracts, were unjustly enriched, and violated principles of equity in connection with their management of the Nuclear Project. The plaintiffs seek compensatory damages and attorneys' fees, and a declaratory judgment as to Santee Cooper's rates. SCANA and SCE&G filed a Motion to Dismiss and to Strike on November 17, 2017.

Shareholder Derivative and 10b-5 Class Actions

On September 26, 2017, a purported shareholder derivative action was filed against defendants Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynne Miller, James Roquemore, Maceo Sloan, Alfredo Trujillo, Jimmy Addison, Stephen Byrne, and nominal defendant SCANA by plaintiff John Crangle, purportedly on behalf of SCANA, in the Richland County Court (the "Crangle Lawsuit"). The plaintiff alleges, among other things, that the defendants breached their fiduciary duties to shareholders by their gross mismanagement of the Nuclear Project, and that the defendants Marsh, Addison, and Byrne were unjustly enriched by bonuses they were paid in connection with the project. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper. Defendants filed motions to dismiss the complaint in December 2017.

On September 27, 2017, a purported class action was filed against SCANA, Kevin B. Marsh, Jimmy E. Addison, and Stephen A. Byrne by plaintiff Robert L. Norman, on behalf of himself and all others similarly situated, in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants are liable under §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On October 5, 2017, a purported class action was filed against SCANA, Kevin B. Marsh, and Jimmy E. Addison by plaintiff Kenneth Evans on behalf of himself and all others similarly situated in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants violated §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On October 30, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynn Miller, James Roquemore, Maceo Sloan, Aldredo Trujillo, Jimmy Addison, Stephen Byrne, and SCANA by plaintiff R. Wayne Todd, purportedly on behalf of SCANA in Richland County Court (the "Todd Lawsuit"). The plaintiff makes substantially similar allegations as those alleged in the Crangle Lawsuit, and alleges that the defendants Marsh, Addison, and Byrne were unjustly enriched by bonuses they were paid in connection with the Nuclear Project. The plaintiff seeks compensatory and consequential damages, punitive damages, attorneys' fees, and any other relief the court deems proper. Defendants filed motions to dismiss the complaint in December 2017.

On November 10, 2017, a purported class action was filed against SCANA, Kevin Marsh, Jimmy Addison, and Steve Byrne by plaintiff Marsha Fox on behalf of herself and all others similarly situated in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants violated §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On November 17, 2017, a purported class action was filed against SCANA, Kevin B. Marsh, Jimmy E. Addison, and Steve B. Byrne by plaintiff West Palm Beach Firefighters' Pension Fund on behalf of itself and all others similarly situated in the District Court. The plaintiff alleges, among other things, that the defendants violated §10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and that the individual named defendants violated §20(a) of the Exchange Act. The plaintiff seeks compensatory and consequential damages, attorneys' fees, and any other relief the court deems proper.

On November 21, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynn Miller, James Roquemore, Maceo Sloan, Aldredo Trujillo, Jimmy Addison, Stephen Byrne, and SCANA by plaintiff Colleen Witmer, purportedly on behalf of SCANA in the District Court. The plaintiff alleges, among other things, that the defendants violated their fiduciary duties to shareholders by disseminating false and misleading information about the Nuclear Project, failing to maintain proper internal controls, failing to properly oversee and manage the company, and that the individual defendants were unjustly enriched in their compensation. The plaintiff seeks compensatory and consequential damages, disgorgement of compensation, punitive damages, attorneys' fees, and any other relief the court deems proper.

On November 22, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Gregory Aliff, James Bennett, John Cecil, Sharon Decker, Maybank Hagood, Lynn Miller, James Roquemore, Maceo Sloan, Aldredo Trujillo, and SCANA by plaintiff Richard Wickstrom, purportedly on behalf of SCANA in the District Court. The plaintiff alleges, among other things, that the defendants violated their fiduciary duties to shareholders by affirmatively making and allowing material misstatements to be made to shareholders regarding the Nuclear Project. The plaintiff seeks compensatory and consequential damages, disgorgement of Marsh's compensation, attorneys' fees, and any other relief the court deems proper.

On December 5, 2017, a purported shareholder derivative action was filed against Kevin B. Marsh, Stephen A. Byrne, Jimmy Addison, Gregory E. Aliff, James A. Bennett, John F.A.V. Cecil, Sharon A. Decker, D. Maybank Hagood, Lynne M. Miller, James W. Roquemore, Maceo K. Sloan, Aldredo Trujillo, James M. Micali, Harold C. Stowe, and nominal defendant SCANA by plaintiff City of Hollywood Employees Retirement Fund in the District Court. The plaintiff alleges, among other things, that the defendants violated their fiduciary duties to shareholders by their gross mismanagement of the Nuclear Project, committed corporate waste, were unjustly enriched, and that the director defendants violated Section 14(a) of the Exchange Act and SEC Rule 14a-9 by allowing or causing misleading proxy statements to be issued in 2016 and 2017. Plaintiff seeks equitable and injunctive relief related to corporate governance functions, as well as compensatory and consequential damages, disgorgement of compensation, attorneys' fees, and any other relief the court deems proper.

On December 13, 2017, a purported shareholder derivative action was filed against Kevin Marsh, Jimmy Addison, Stephen Byrne, Maybank Hagood, Lynne Miller, James Bennett, Maceo Sloan, Sharon Decker, James Roquemore, Alfredo Trujillo, John F.A.V. Cecil, Gregory Aliff, James Micali, Harold Stowe, and nominal defendant SCANA by plaintiff Firemen's Retirement System of St. Louis, purportedly on behalf of SCANA, in the Richland County Court. The plaintiff makes substantially similar allegations as those alleged in the Crangle and Todd Lawsuits. The plaintiff seeks compensatory and consequential damages, injunctive relief, restitution, attorneys' fees, and any other relief the court deems proper.

Contractor Lien Litigation

On April 27, 2017, SCE&G filed a declaratory judgment lawsuit in the Fairfield County Court against Structural Preservation Systems, Inc., a subcontractor to WECTEC and several dozen other companies that were WECTEC subcontractors, or who otherwise provided such labor and materials for other companies for the use and benefit of WECTEC (collectively, the "WECTEC Subcontractors"), who claimed that WECTEC had not paid them for work on the Nuclear Project.

The lawsuit was filed for the purpose of asserting SCE&G's common defenses to such claims by the WECTEC Subcontractors that WECTEC owed them payment for labor or materials they supplied on the project. Since that time, more than 40 individual cases have been filed by WECTEC Subcontractors against SCE&G and Santee Cooper asserting statutory and common law claims against both entities for alleged non-payment by WECTEC. On September 29, 2017, SCE&G obtained a court order consolidating all current and future lawsuits among SCE&G, Santee Cooper, and the WECTEC Subcontractors arising out of allegations of non-payment of the WECTEC Subcontractors by WEC. SCE&G also obtained a court order that designated all such lawsuits as complex and assigning them to one judge. Finally, SCE&G obtained a third court order that stayed any party's otherwise required response to any lawsuit, claim, cross-claim, counterclaim, or third party claim in these lawsuits until the parties could work on case management issues and present a plan for case management to the judge assigned the cases. The lawsuits are in the pleadings stage. The WECTEC Subcontractors have made claims including but not limited to foreclosure of mechanics liens, common law theories including but not limited to negligence and breach of contract, equitable theories including the imposition of a constructive trust on the Toshiba settlement proceeds, damages, and injunctive relief.

FILOT Litigation

On November 29, 2017, Fairfield County filed a Complaint and a Motion for Temporary Injunction against SCE&G making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of the implied duty of good faith and fair dealing, and unfair trade practices related to SCE&G's termination of the FILOT agreement. Plaintiff sought a temporary and permanent injunction to prevent SCE&G from terminating the FILOT; actual and consequential damages; treble damages; punitive damages; and attorneys' fees. Plaintiff sought a hearing within ten days on their motion for temporary injunction. The Court heard arguments on December 15, 2017 on the motion for temporary injunction, and asked the parties to submit supplemental briefing and proposed orders by December 20, 2017. Plaintiff voluntarily withdrew the Motion for Temporary Injunction on December 20, 2017. The Court set a hearing for February 8, 2018 on SCE&G's Motion to Transfer Venue.

Regulatory Proceedings and Investigations

On June 22, 2017, the Friends of the Earth and the Sierra Club filed a complaint against SCE&G with the SCPSC, requesting that the SCPSC initiate a formal proceeding to direct SCE&G to immediately cease and desist from expending any further capital costs related to the construction of Unit 2 and Unit 3; to determine the prudence of acts and omissions by SCE&G in connection with the construction of Unit 2 and Unit 3; to review and determine the prudence of abandonment of the Nuclear Project and of the available least cost efficiency and renewable energy alternatives; and to remedy, abate and make due reparations for the rates charged to ratepayers related to the construction of Unit 2 and Unit 3. SCE&G filed its answer to the complaint on July 19, 2017. SCE&G has filed a motion to dismiss the plaintiff's complaint, which motion was argued at a hearing held on December 13, 2017. On December 20, 2017, the SCPSC, among other things, denied SCE&G's motion to dismiss and ordered that the matter be consolidated with proceedings related to the Request, described below.

On September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon an opinion of the South Carolina Office of Attorney General issued on the same date, to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the South Carolina General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed with the SCPSC a motion to amend its request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. A hearing on the parties' motions was held on December 12, 2017, and included the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, a large industrial customer, and several environmental groups. In addition, on November 20, 2017, the ORS filed a letter with the SCPSC providing ORS's preliminary list for stabilization and protection of the site containing Unit 2 and Unit 3 and suggesting that the SCPSC have SCE&G respond to ORS's November 20, 2017 letter and "explain why there is no violation of S.C. Code Ann. § 58-27-1300." The SCPSC granted ORS's request, and SCE&G filed its response with the SCPSC on December 27, 2017.

By order dated December 20, 2017, the SCPSC denied SCE&G's Motion to Dismiss the Request and ordered that a hearing be set on the Request. In addition, the SCPSC ordered ORS to perform a thorough inspection and audit, within 30 days, to determine the reasonableness of SCE&G's retail electric rates and to determine the reasonableness of SCE&G's statements regarding the potential effect that the removal of approximately $445 million in annual revenues, as requested by the ORS, could have on SCE&G. The SCPSC also granted ORS's motion to amend the Request and consider the monetization of the Toshiba payout along with any other related factors that may be appropriate in determining a fair and reasonable rate. Lastly, the order consolidated the Friends of the Earth and Sierra Club petition with the Request.

The Company has also been served with subpoenas issued by the United States Attorney's Office for the District of South Carolina and the staff of the SEC's Division of Enforcement seeking documents relating to the Nuclear Project. In addition, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee have requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. The Company and Consolidated SCE&G intend to fully cooperate with any such investigations.

On November 30, 2017, the SCPSC served upon SCE&G a document styled as "South Carolinians Against Monetary Abuse (SCAMA) and Leslie Minerd v. South Carolina Electric & Gas Company" requesting that SCE&G include a line item on customers' monthly bill identifying the charges incurred as a result of the BLRA. On December 29, 2017, SCE&G filed its Answer and Motion to Dismiss and requested that the testimony deadlines and hearing date be held in abeyance pending a determination on SCE&G's Motion to Dismiss.

Bankruptcy Court Litigation

On March 29, 2017, WEC and WECTEC and certain of their affiliates filed petitions for protection under Chapter 11 of the U.S. Bankruptcy Code with the Bankruptcy Court. On September 1, 2017, SCE&G, for itself and as agent for Santee Cooper, filed with the Bankruptcy Court Proofs of Claim for unliquidated damages against each of WEC and WECTEC. The Proofs of Claim are based upon the anticipatory repudiation and material breach by the Consortium of the EPC Contract, and assert against WEC any and all claims that are based thereon or that may be related thereto. On September 27, 2017, SCE&G sold substantially all of its interest in the Toshiba Settlement and assigned all of its claims under the WEC bankruptcy process to Citibank. SCE&G has agreed to use commercially reasonable efforts to cooperate with Citibank and provide reasonable support necessary for its enforcement of those claims. Notwithstanding the sale of the claims, SCE&G and Santee Cooper remain responsible for any claims that may be made by WEC and WECTEC against them relating to the EPC Contract.

Employment Class Action

On August 8, 2017, a purported class action was filed against SCANA, SCE&G, and its co-defendants Fluor and Fluor Enterprises, Inc., by plaintiffs Harry Pennington III and Timothy Lorenz, on behalf of themselves and all others similarly situated, in the District Court. The plaintiffs allege, among other things, that the defendants violated the Worker Adjustment and Retraining Notification Act ("WARN Act") in connection with the decision to stop construction on the Nuclear Project. The plaintiffs allege that the defendants failed to provide adequate advance written notice of their terminations of employment.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all wholly-owned subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Jimmy E. Addison	57	Chief Executive Officer and President-SCANA President and Chief Operating Officer-SCANA Energy Executive Vice President-SCANA and Chief Financial Officer	2018-present 2014-2018 *- 2017
Jeffrey B. Archie	60	Senior Vice President and Chief Nuclear Officer-SCE&G Senior Vice President-SCANA	*-present *-present
Sarena D. Burch	60	Senior Vice President-Risk Management and Corporate Compliance Senior Vice President-Fuel Procurement and Asset Management-SCANA, SCE&G and PSNC Energy	2016-present *-2015
Iris N. Griffin	41	Senior Vice President, Chief Financial Officer and Treasurer Vice President - Finance and Treasurer Associate Treasurer Director - Audit Services, Privacy and Corporate Compliance Officer Manager - Investor Relations	2018-present 2016-2017 2015-2016 2013-2015 *-2013
D. Russell Harris	53	President-Gas Operations-SCE&G President and Chief Operating Officer-PSNC Energy President and Chief Operating Officer-SCANA Energy Senior Vice President-SCANA	2013-present *-present 2018-present 2013-present
Kenneth R. Jackson	61	Senior Vice President-Economic Development, Governmental and Regulatory Affairs Vice President-Rates and Regulatory Services	2014-present *-2014
W. Keller Kissam	51	President-Generation, Transmission and Distribution and Chief Operating Officer-SCE&G President-Retail Operations-SCE&G Senior Vice President-SCANA	2018-present *-2017 *-present
Randal M. Senn	61	Senior Vice President-Administration-SCANA Vice President and Chief Information Officer Chief Information Officer	2016-present 2016 *-2016
Jim Odell Stuckey	49	Senior Vice President, General Counsel and Assistant Secretary Director - Legal Department and Deputy General Counsel Director - Legal Department and Associate General Counsel	2017-present 2014-2017 *- 2014

*Indicates positions held at least since February 23, 2013.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

SCANA:

Price Range (NYSE Composite Listing):

	2017				2016			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 50.22	$ 68.35	$ 71.28	$ 72.75	$ 74.94	$ 76.41	$ 75.67	$ 70.35
Low	$ 37.10	$ 48.32	$ 63.90	$ 63.63	$ 67.31	$ 69.04	$ 66.02	$ 59.46

SCANA common stock trades on the NYSE using the ticker symbol SCG. At February 20, 2018 there were approximately 143 million shares of SCANA common stock outstanding which were held by approximately 23,100 shareholders of record. See Item 12 for a summary of equity securities issuable under SCANA's compensation plans at December 31, 2017.

SCANA declared quarterly dividends on its common stock of $0.6125 per share in 2017 and $0.575 per share in 2016. On February 22, 2018, SCANA declared a quarterly cash dividend on SCANA common stock of $0.6125 per share, which quarterly dividend is payable April 1, 2018 to shareholders of record on March 12, 2018. For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

The following table provides information about purchases by or on behalf of SCANA or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended (Exchange Act)) of shares or other units of any class of SCANA's equity securities that are registered pursuant to Section 12 of the Exchange Act:

Issuer Purchases of Equity Securities

	(a)	(b)	(c)	(d)
Period	Total number of shares (or units) purchased	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1-31, 2017	7,964	$ 49.01	7,964	
November 1-30, 2017	—	—	—	
December 1-31, 2017	—	—	—	
Total	7,964		7,964	*

*The above table represents shares acquired for non-employee directors under the Director Compensation and Deferral Plan. On December 16, 2014, SCANA announced a program to convert from original issue to open market purchase of SCANA common stock for all applicable compensation and dividend reinvestment plans. This program took effect in the first quarter of 2015 and has no stated maximum number of shares that may be purchased and no stated expiration date.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2017 and 2016, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount
February 16, 2017	$ 76.9 million	February 18, 2016	$ 72.2 million
April 27, 2017	78.1 million	April 28, 2016	73.3 million
August 3, 2017	78.5 million	July 28, 2016	74.0 million
October 26, 2017	80.6 million	October 27, 2016	77.5 million

On February 22, 2018, SCE&G declared a quarterly dividend on its common stock of $71.9 million.

For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2017	2016	2015	2014	2013
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Operations Data					
Operating Revenues	$ 4,407	$ 4,227	$ 4,380	$ 4,951	$ 4,495
Operating Income	$ 87	$ 1,153	$ 1,308	$ 1,007	$ 910
Net Income (Loss)	$ (119)	$ 595	$ 746	$ 538	$ 471
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.6	142.6	142.6	142.6	138.4
Basic Earnings (Loss) Per Share	$ (0.83)	$ 4.16	$ 5.22	$ 3.79	$ 3.40
Diluted Earnings (Loss) Per Share	$ (0.83)	$ 4.16	$ 5.22	$ 3.79	$ 3.39
Dividends Declared Per Share of Common Stock	$ 2.45	$ 2.30	$ 2.18	$ 2.10	$ 2.03
Balance Sheet Data					
Utility Plant, Net	$ 10,648	$ 14,324	$ 13,145	$ 12,232	$ 11,643
Total Assets	$ 18,739	$ 18,707	$ 17,146	$ 16,818	$ 15,127
Total Equity	$ 5,255	$ 5,725	$ 5,443	$ 4,987	$ 4,664
Short-term and Long-term Debt	$ 6,983	$ 7,431	$ 6,529	$ 6,581	$ 5,788
Other Statistics					
Electric:					
Customers (Year-End)	718,822	709,418	698,372	687,800	678,273
Total sales (Million kWh)	22,866	23,458	23,102	23,319	22,313
Generating capability-Net MW (Year-End)	5,233	5,233	5,234	5,237	5,237
Territorial peak demand-Net MW	4,701	4,807	4,970	4,853	4,574
Regulated Gas:					
Customers, excluding transportation (Year-End)	930,790	906,883	881,295	859,186	837,232
Sales, excluding transportation (Thousand Therms)	857,886	890,113	875,218	973,907	921,533
Transportation customers (Year-End)	616	632	627	656	667
Transportation volumes (Thousand Therms)	700,254	674,999	791,402	1,786,897	1,729,399

The comparability of Selected Financial Data is affected by the following:

In 2017, as a result of the decision to stop construction on Unit 2 and Unit 3, approximately $4.7 billion (prior to an estimated impairment loss) was reclassified from construction work in progress within Utility Plant, Net into regulatory assets. In addition, a pre-tax impairment loss of $1.1 billion was recorded. See Note 10 to the consolidated financial statements. Finally, deferred income tax assets and liabilities were remeasured in connection with the enactment of the Tax Act, resulting in an increase in Net Loss of approximately $30 million.

In 2015, a regulated gas operating subsidiary and a non-operating subsidiary were sold, resulting in pre-tax gains totaling approximately $342 million. See Note 1 to the consolidated financial statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pursuant to General Instruction I of Form 10-K, SCE&G is permitted to omit certain information related to itself and its consolidated affiliates called for by Item 7 of Form 10-K, and instead provide a management's narrative explanation of its consolidated results of operation and other information described therein. Such information is presented hereunder specifically for Consolidated SCE&G, but may be presented alongside information presented for the Company generally. Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation and its subsidiaries (other than Consolidated SCE&G).

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

Key Earnings Drivers and Outlook

The outcome of contentious regulatory, legislative and court proceedings stemming from the Company's July 31, 2017 decision to stop construction of Unit 2 and Unit 3 and to seek recovery of its investment in the abandoned Nuclear Project will significantly affect the Company's future earnings. These proceedings could result in the SCPSC ordering SCE&G to cease collecting BLRA-related rates and to immediately refund such amounts previously collected. Such an outcome would likely result in degraded credit ratings with a corresponding higher cost of capital, if such capital were available at all. In 2017, the Company's principal subsidiary, SCE&G, recorded an aggregate pre-tax impairment loss of $1.118 billion related to the abandoned Nuclear Project. These matters are discussed further in Electric Operations below, in Liquidity and Capital Resources herein and in Note 10 to the consolidated financial statements.

On January 2, 2018, SCANA entered into the Merger Agreement with Dominion Energy. Under the terms of that agreement, Dominion Energy would provide the financial support for SCE&G to make a $1.3 billion up-front, one time rate credit to SCE&G's electric customers to be paid within 90 days of the closing of the merger, a $575 million refund along with the benefits of the Tax Act resulting in at least a 5% reduction to SCE&G electric service customers' bills over an eight-year period, and the exclusion from rate recovery of approximately $1.7 billion of costs related to the Nuclear Project. These terms, together with other terms and commitments in the Merger Agreement and the Joint Petition, could resolve many of the outstanding issues related to the Nuclear Project. The Company targets the closing of the merger by the end of 2018. Significant hurdles must be overcome before closing may occur, however, including the receipt of the requisite authorizations, approvals, consents and/or permits from various federal and state regulatory entities and the approval of two-thirds of the shares represented by SCANA's shareholders. Regulatory approvals of the merger may not be obtained on a timely basis or at all, and such approvals may include conditions that could have an adverse effect on the Company and Consolidated SCE&G or result in the abandonment of the merger. No assurance can be provided that the necessary approvals will be obtained or that any required conditions will not have an adverse effect on Consolidated SCE&G following the merger. See additional discussion in Item 1A. Risk Factors and in Note 2 and Note 10 to the consolidated financial statements.

Electric Operations

SCE&G's electric operations primarily generate electricity and provide for its transmission, distribution and sale to approximately 719,000 customers (as of December 31, 2017) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity compared to other energy sources.

Embedded in the rates charged to customers is an allowed regulatory ROE. SCE&G’s allowed ROE in 2017 was 10.25% for non-BLRA rate base. For BLRA-related rate base existing prior to 2016, SCE&G's ROE was 11.0%, and for such rate base arising in 2016, the ROE was 10.5%. As described in Note 2 to the consolidated financial statements, the SCPSC revised SCE&G's ROE for Nuclear Project costs to 10.25%, which was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. No revised rates filing was pursued in 2017. Uncertainties that are expected to adversely impact ROE on BLRA-related rate base are discussed in Abandoned Nuclear Project herein and in Note 10 to the consolidated financial statements.

In 2017, the enactment of federal environmental laws and regulations related to the generation of electricity slowed significantly; however, public sentiment surrounding air quality and water quality remains strong and is expected to continue. Over several years, SCE&G has incurred significant costs and made substantial investments to comply with federal environmental initiatives, including the retirement of certain coal-fired plants and the conversion of others to burn natural gas. In addition, SCE&G has added the renewable energy from several new solar generating facilities at locations throughout its electric service territory. In addition, SCE&G and GENCO have installed pollution control equipment at their remaining coal-fired plants, which have resulted in reduced air emissions. The status of significant environmental laws and regulations and certain initiatives undertaken to ensure compliance with them are described in Environmental Matters herein and in Note 10 to the consolidated financial statements.

Abandoned Nuclear Project

Significant events leading up to the Company's decision to abandon the Nuclear Project include the following:

- On July 1, 2016, SCE&G, on behalf of itself and as agent for Santee Cooper, elected the fixed price option as provided for in the October 2015 Amendment to the EPC Contract, subject to SCPSC approval. The fixed price option was designed to shift the risk of significant cost overruns from SCE&G and Santee Cooper by fixing the total amount to be paid to the Consortium for its entire scope of work on the project, with limited exceptions.

- On November 9, 2016, the SCPSC approved SCE&G's election of the fixed price option.

- On March 29, 2017, WEC and WECTEC filed petitions for protection under Chapter 11 of the U.S. Bankruptcy Code, citing a liquidity crisis arising from project contract losses attributable to the Nuclear Project and similar units being built for an unaffiliated company as a material factor that caused them to seek protection under the bankruptcy laws. As part of their filing, WEC and WECTEC publicly announced their inability to complete Unit 2 and Unit 3 under the fixed price terms of the EPC Contract.

- In connection with the bankruptcy filing, SCE&G, Santee Cooper, WEC and WECTEC entered into an Interim Assessment Agreement under which engineering and construction continued on the project and under which SCE&G and Santee Cooper were provided the right to discuss project status with Fluor and other subcontractors and vendors and to obtain from them relevant project information and documents that had been previously contractually unavailable in order for SCE&G and Santee Cooper to perform comprehensive analyses regarding whether or how to proceed with the project.

- On July 31, 2017, based on the results of its analysis and in light of Santee Cooper's decision to suspend construction on the units, the Company determined to stop the construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with their construction under the abandonment provisions of the BLRA or through other regulatory means.

The Company's decision to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with their construction have been the subject of contentious proceedings before the SCPSC and special committees of the South Carolina legislature. The Governor has likewise asserted, among other things, that the BLRA should be replaced and any further collection of money from customers for the Nuclear Project should be prevented. The SCPSC is actively considering a request that could result in the suspension of rates currently being collected by SCE&G under the BLRA (approximately $445 million annually, which includes collections related to transmission assets expected to be placed into service), that could require the return of such amounts previously collected (approximately $1.9 billion as of December 31, 2017), and that will affect when and in what manner proceeds arising from the Toshiba guaranty (approximately $1.1 billion) will be used for the benefit of SCE&G customers.

Proposals to Resolve Outstanding Issues

On November 16, 2017, SCE&G announced for public consideration a proposal to resolve outstanding issues relating to the Nuclear Project. Under the proposal, SCE&G electric customers were to receive a 3.5% electric rate reduction, the addition of an existing 540-MW natural gas fired power plant by SCE&G with the acquisition cost borne by SCANA shareholders, and the addition of approximately 100-MW of large scale solar energy by SCE&G. The proposal also provided for the recovery of the nuclear construction costs (net of the proceeds of the Toshiba Settlement not utilized for liquidation of project liens) over 50 years. While SCE&G's proposal was not formally submitted for regulatory approval, discussions with key stakeholders over the ensuing weeks indicated that SCE&G's proposal would not be sufficient to resolve the outstanding issues.

On January 2, 2018, SCANA entered into the Merger Agreement with Dominion Energy, and on January 12, 2018, SCE&G and Dominion Energy filed the Joint Petition requesting SCPSC approval of the merger or a finding that either the merger is in the public interest or that there is an absence of harm arising from the merger. In the Joint Petition, among other things, the parties commit to providing an up-front, one time rate credit to SCE&G's electric customers totaling approximately $1.3 billion within 90 days of the merger's closing, at least a 5% reduction in customer bills, shortening the amortization period for recovery of costs related to the Nuclear Project to 20 years, forgoing recovery of approximately $1.7 billion in costs related to the Nuclear Project, and the addition of an existing 540-MW natural gas fired power plant by SCE&G with no initial investment borne by customers. The petition also puts forth other less-favored alternatives for rate recovery in the event the joint proposal were not to be accepted by the SCPSC and the merger were not to be consummated.

The outcome of these matters is uncertain, and any resolution adverse to the Company and Consolidated SCE&G could adversely affect results of operations, cash flows and financial condition. These matters and others are further discussed in Liquidity and Capital Resources and in Note 2 and Note 10 to the consolidated financial statements.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 931,000 retail customers (as of December 31, 2017) in portions of South Carolina and North Carolina in areas covering approximately 35,000 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory ROE for SCE&G of 10.25% and for PSNC Energy of 9.7%.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company's ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at generally low levels for several years. The supply of natural gas from the Marcellus shale basin has prompted Dominion Energy and other companies unaffiliated with SCANA to propose construction of an approximately 600-mile pipeline that would bring natural gas from West Virginia to Virginia and North Carolina. This pipeline is expected to be completed in late 2019 and, if successful, it may drive economic development along its path, including areas within PSNC Energy's service territory, and may serve to assist in keeping natural gas competitively priced in the region.

Gas Marketing

SCANA Energy markets natural gas in the southeast and provides energy-related services to customers, including retail customers in Georgia. Operating results for energy marketing are influenced by customer demand for natural gas and the ability to control costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, the availability of certain pipeline capacity to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the Georgia retail market. SCANA Energy sells natural gas to over 425,000 customers (as of December 31, 2017) throughout Georgia. This market is mature, resulting in low margins and significant competition from affiliates of large energy companies and electric membership cooperatives, among others. SCANA Energy's ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy's operating results are sensitive to the impacts of weather on customer demand.

RESULTS OF OPERATIONS

Earnings (Loss) and dividends were as follows:

	2017	2016	2015
The Company			
Earnings (loss) per share	$ (0.83)	$ 4.16	$ 5.22
Cash dividends declared per share	$ 2.45	$ 2.30	$ 2.18
Consolidated SCE&G			
Net income (loss) (millions of dollars)	$ (171.9)	$ 525.8	$ 479.5

On February 22, 2018, SCANA declared a quarterly cash dividend on its common stock of $0.6125 per share.

2017 vs 2016

The Company's earnings (loss) per share and Consolidated SCE&G's net income (loss) primarily reflects an operating loss from Electric Operations, which includes an impairment loss associated with the abandonment of the Nuclear Project, partially offset by improved operating income from Gas Distribution. In addition, the Company's earnings (loss) per share reflects a loss resulting from enactment of the Tax Act. These and other results are discussed below.

2016 vs 2015

The Company's earnings per share and Consolidated SCE&G's net income reflects higher operating income from Electric Operations and Gas Distribution. The Company's earnings per share also reflects higher net income from Gas Marketing. These and other results are discussed below.

Matters Impacting Future Results

The Company's decision on July 31, 2017 to stop construction of Unit 2 and Unit 3 and to pursue recovery of the cost of the abandoned Nuclear Project has had and could continue to have significant impacts on the Company's and Consolidated SCE&G's future earnings, cash flows and financial position, including those related to the ultimate recovery of regulatory assets and the sustainability of tax positions. The Company continues to believe the decision to abandon the Nuclear Project was prudent and that costs incurred with respect to the project were prudent, have contested specific challenges to this decision, and believe that the issues related to the recovery of the cost of the abandoned Nuclear Project and related to the rates currently being collected under the BLRA for financing costs should be resolved in future proceedings before the SCPSC. However, based on various events following the abandonment, there is significant uncertainty as to SCE&G's ultimate ability to fully recover its costs of Unit 2 and Unit 3 and a return on them from its customers. These events include the contentious nature of ongoing reviews by legislative committees and others, legislative proposals being considered by the General Assembly and promoted by the Governor, and the Request being considered by the SCPSC that could result in the suspension of rates currently being collected under the BLRA, as well as the return of such amounts previously collected.

The Company and Consolidated SCE&G have determined that a disallowance of recovery of part of the cost of the abandoned plant is both probable and reasonably estimable under applicable accounting guidance, and have recorded a pre-tax impairment loss with respect to disallowance of unrecovered nuclear project costs and other related deferred costs totaling approximately $1.118 billion. This amount includes $210 million recorded in the third quarter of 2017 and the remaining $908 million recorded in the fourth quarter of 2017. For additional discussion, see Impairment Considerations in Critical Accounting Policies and Estimates and Note 10 to the consolidated financial statements.

It is reasonably possible that further changes in these estimates will occur in the near term and could be material; however, all such changes cannot be reasonably estimated. The above impairment loss reflects impacts similar to those that would have resulted had the proposed solution announced November 16, 2017 been implemented. If the merger benefits and cost recovery plan outlined in the Joint Petition is implemented (upon closing of the merger as contemplated in the Merger Agreement), an additional impairment loss and other charges totaling as much as approximately $1.7 billion would be expected to be recorded. If instead the Joint Petition is not approved and the Request by the ORS is approved, if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, the Company and Consolidated SCE&G may be required to record an additional impairment loss and other charges totaling as much as approximately $4.8 billion. This additional impairment loss would result from the write-off of the remaining unrecovered Nuclear Project costs of $3.976 billion recorded within regulatory assets and the refund of revised rates collections under the BLRA described above of approximately $1.9 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. The Company and Consolidated SCE&G do not currently anticipate that any of the $1.9 billion in revenue previously collected will be subject to refund; however, no assurance can be given as to the outcome of this matter.

In December 2017, the Tax Act was enacted, resulting in the remeasurement of all federal deferred income tax assets and liabilities to reflect a 21% federal statutory corporate tax rate. Due to the regulated nature of the Company's and Consolidated SCE&G's operations, the effect of this remeasurement is primarily reflected in excess deferred income tax balances within regulatory liabilities. As described in Note 2 to the consolidated financial statements, SCE&G and PSNC Energy have responded to orders from state regulators seeking information on the effects the Tax Act would have on their respective operations. The Company and Consolidated SCE&G cannot determine the amount or timing of any refunds to customers that may result. Going forward, the Company and Consolidated SCE&G expect that the lower tax expense resulting from the reduced federal statutory tax rate will result in similar reductions to amounts collected from customers through electric and gas rates, and no significant impact on financial results are expected. See also Note 5 to the consolidated financial statements for additional discussion related to deferred tax assets and deferred tax liabilities.

These matters impacting future results are further discussed under Impact of Abandonment of Nuclear Project within LIQUIDITY AND CAPITAL RESOURCES, in Note 2 and Note 10 to the consolidated financial statements and in Part I, Item 1A. Risk Factors.

Electric Operations

Electric Operations for the Company and for Consolidated SCE&G is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric Operations operating income (including transactions with affiliates) was as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Operating revenues	$ 2,664.4	$ 2,619.4	$ 2,557.1	$ 2,664.4	$ 2,619.4	$ 2,557.1
Fuel used in electric generation	593.6	576.1	660.6	593.6	576.1	660.6
Purchased power	80.1	63.7	52.1	80.1	63.7	52.1
Other operation and maintenance	519.0	526.1	497.1	533.4	540.2	509.6
Impairment loss	1,118.1	—	—	1,118.1	—	—
Depreciation and amortization	294.7	286.5	277.3	282.8	274.9	266.9
Other taxes	220.3	210.4	194.5	217.8	207.9	192.4
Operating Income (Loss)	$ (161.4)	$ 956.6	$ 875.5	$ (161.4)	$ 956.6	$ 875.5

Electric operations can be significantly impacted by the effects of weather. SCE&G estimates the effects on its electric business of actual temperatures in its service territory as compared to historical averages to develop an estimate of electric revenue and fuel costs attributable to the effects of abnormal weather. Results in 2017 reflect milder than normal weather in the first and fourth quarters and warmer than normal weather in the second and third quarters. Results in 2016 reflect significantly warmer than normal weather in the second and third quarters and milder than normal weather in the first and fourth quarters. Results in 2015 reflect colder than normal weather in the first quarter, warmer than normal weather in the second and third quarters and milder than normal weather in the fourth quarter.

2017 vs 2016

- Operating revenue increased due to revised rates increases under the BLRA of $57.6 million, residential and commercial growth of $29.4 million, industrial growth and higher usage of $5.5 million, increased revenue recognized under the DER program of $7.3 million and higher fuel cost recovery of $48.1 million. These revenue increases were partially offset by the effects of milder weather of $77.7 million, lower residential and commercial average use of $18.9 million and lower collections under the rate rider for pension costs of $4.0 million. The lower pension rider collections had no impact on net income as they were fully offset by the recognition, within other operation and maintenance expenses, of lower pension costs.

- Fuel used in electric generation and purchased power expenses increased due to higher fuel prices of $48.1 million, amortization of DER program costs of $3.9 million and increased sales volumes associated with residential and commercial customer growth of $5.8 million. These increases were partially offset due to lower sales volumes associated with the effects of milder weather of $15.9 million, lower residential and commercial average use of $4.1 million, lower industrial usage of $1.6 million and lower fuel handling expenses of $2.4 million.

- Other operation and maintenance expenses decreased due to lower labor costs of $24.0 million, primarily due to lower incentive compensation costs and lower pension costs associated with the lower pension rider collections, partially offset by nuclear abandonment-related severance costs of $12.3 million. This decrease was offset by higher non-labor electric generation costs of $2.2 million and due to wind down and other costs associated with the abandonment of the Nuclear Project of $10.9 million.

- Impairment loss represents the estimate of the probable disallowance of recovery associated with the abandonment of the Unit 2 and Unit 3 of $670 million, a write down to estimated fair value of the carrying value of nuclear fuel acquired for use in Unit 2 and Unit 3 of $87 million and an aggregate amount of $361 million to write off costs which had been previously deferred primarily within regulatory assets in connection with the Nuclear Project.

- Depreciation and amortization increased primarily due to net plant additions.

- Other taxes increased primarily due to higher property taxes associated with net plant additions.

2016 vs 2015

- Operating revenue increased due to revised rates increases under the BLRA of $60.7 million, residential and commercial growth of $29.0 million, industrial growth and higher usage of $9.7 million, increased revenue recognized under the DER program of $5.8 million, the effects of weather of $28.2 million and higher collections under the rate rider for pension costs of $13.5 million. The higher pension rider collections had no impact on net income as they were fully offset by the recognition, within other operation and maintenance expenses, of higher pension costs. Revenue also increased due to downward adjustments in 2015, pursuant to orders from the SCPSC, to apply $14.5 million as an offset to fuel cost recovery upon the adoption of new (lower) electric depreciation rates and by $5.2 million related to DSM Programs. These adjustments had no effect on net income in 2015 as they were fully offset by the recognition of $14.5 million of lower depreciation expense and by the recognition, within other income, of $5.2 million of gains realized upon the settlement of certain interest rate contracts. These revenue increases were partially offset by lower fuel cost recovery of $84.1 million and lower residential and commercial average use of $19.5 million.

- Fuel used in electric generation and purchased power expenses decreased due to lower fuel prices of $84.1 million, lower sales volumes associated with residential and commercial average use of $4.2 million and lower fuel handling expenses of $2.3 million. These decreases were partially offset due higher to amortization of DER program costs of $4.6 million, higher industrial usage of $1.9 million, increased sales volumes associated with residential and commercial customer growth of $6.4 million and higher sales volumes associated with the effects of weather of $4.9 million.

- Other operation and maintenance expenses increased due to higher labor costs of $25.4 million, primarily due to increased pension costs associated with the higher pension rider collections and higher incentive compensation costs. Other operation and maintenance expenses also increased due to higher amortization of DSM program costs of $2.0 million.

- Depreciation and amortization increased primarily due to net plant additions.

- Other taxes increased primarily due to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric operations above, by class, were as follows:

Classification	2017	2016	2015
Residential	7,782	8,140	7,978
Commercial	7,372	7,506	7,386
Industrial	6,212	6,265	6,201
Other	584	600	595
Total retail sales	21,950	22,511	22,160
Wholesale	916	947	942
Total Sales	22,866	23,458	23,102

2017 vs 2016

Retail and wholesale sales volumes decreased primarily due to the effects of weather, partially offset by increases associated with customer growth.

2016 vs 2015

Retail sales volumes increased primarily due to the effects of weather and customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G, and for the Company, also includes PSNC Energy. Gas Distribution operating income (including transactions with affiliates) was as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	2017	2016	2015	2017	2016	2015
Operating revenues	$ 876.0	$ 789.8	$ 811.7	$ 405.8	$ 366.8	$ 372.7
Gas purchased for resale	393.0	345.9	383.7	205.9	182.9	192.5
Other operation and maintenance	168.9	172.7	161.4	70.6	73.6	69.8
Depreciation and amortization	84.9	82.0	77.5	29.0	27.3	26.8
Other taxes	42.5	41.5	37.5	28.5	26.8	24.9
Operating Income	$ 186.7	$ 147.7	$ 151.6	$ 71.8	$ 56.2	$ 58.7

The effect of abnormal weather conditions on gas distribution margin is mitigated by the WNA at SCE&G and the CUT at PSNC Energy as further described in Revenue Recognition in Note 1 of the consolidated financial statements. The WNA and CUT do not affect sales volumes.

2017 vs 2016

- Operating revenue increased at SCE&G primarily due to increased base rates under the RSA of $6.7 million, customer growth of $11.7 million and higher gas cost recovery of $14.9 million. These increases were partially offset by lower average use of $1.6 million. In addition to these factors, operating revenue increased at the Company due to PSNC Energy's higher gas cost collections of $28.9 million, a rate increase of $14.9 million, customer growth of $8.1 million and higher CUT of $17.2 million. These increases at PSNC Energy were partially offset by milder weather and declining consumption of $18.8 million.

- Gas purchased for resale at SCE&G increased due to higher gas prices of $15.7 million and increased sales volumes associated with firm customer growth of $7.1 million. In addition to these factors, gas purchased for resale at the Company increased primarily due to PSNC Energy's higher gas costs of $28.9 million and customer growth of $2.2 million that were partially offset by milder weather and declining consumption of $7.3 million.

- Other operation and maintenance expenses decreased primarily due to lower labor costs of $4.9 million at SCE&G and $10.9 million at PSNC Energy, due primarily to lower incentive compensation costs. These decreases were partially offset by higher non-labor costs of $1.7 million at SCE&G and $8.6 million at PSNC Energy.

- Depreciation and amortization increased primarily due to net plant additions.

- Other taxes increased primarily due to higher property taxes associated with net plant additions.

2016 vs 2015

- Operating revenue decreased at SCE&G primarily due to lower gas cost recovery of $17.6 million and lower firm average use of $6.1 million. These decreases were partially offset by increased base rates under the RSA of $2.6 million and firm customer growth of $13.1 million. In addition to these factors, operating revenue decreased at the Company due to PSNC Energy's lower gas cost collections of $45.4 million. These decreases at PSNC Energy were partially offset by a rate increase of $6.5 million, increased customer growth of $10.3 million and higher CUT of $13.8 million.

- Gas purchased for resale at SCE&G decreased due to lower gas prices of $17.6 million. These decreases at SCE&G were partially offset by increased sales volumes associated with firm customer growth of $6.5 million. In addition to these factors, gas purchased for resale at the Company decreased due to PSNC Energy's decreased gas cost of $45.4 million and an excess state deferred income tax refund of $1.9 million. This decrease at PSNC Energy was partially offset by customer growth of $3.8 million, as well as higher CUT of $15.5 million.

- Other operation and maintenance expenses increased due to higher labor costs of $2.1 million at SCE&G and $6.7 million at the Company, due primarily to higher incentive compensation costs.

- Depreciation and amortization increased due to net plant additions, partially offset by the implementation of SCPSC-approved revised (lower) depreciation rates at SCE&G of $1.1 million.

- Other taxes increased primarily due to net plant additions.

Sales volumes (in MMBTU) related to gas distribution by class, including transportation, were as follows:

	The Company			Consolidated SCE&G		
Classification (in thousands)	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Residential	37,251	40,142	39,090	11,285	12,420	12,086
Commercial	28,429	29,078	28,064	12,565	12,879	12,580
Industrial	20,108	19,364	20,101	18,091	17,228	17,901
Transportation gas	51,587	49,769	49,297	6,229	5,250	4,781
Total	137,375	138,353	136,552	48,170	47,777	47,348

2017 vs 2016

Residential and commercial sales volumes decreased due to the effects of weather and lower average use. These decreases were partially offset by customer growth. Industrial sales volumes at SCE&G increased due to fewer curtailments and customer growth. Transportation volumes at SCE&G increased primarily due to firm customers transporting rather than purchasing system supply. Transportation volumes at PSNC Energy increased primarily due to firm service expansion partly offset by a decline in natural gas fired electric generation transportation and milder weather.

2016 vs 2015

Residential and commercial firm sales volumes increased primarily due to customer growth. Commercial and industrial interruptible volumes decreased, and firm volumes increased, due to customers switching from interruptible to firm service at SCE&G. Industrial volumes decreased and transportation volumes increased due to customers switching to transportation only service.

Gas Marketing

Gas Marketing is comprised of the Company’s nonregulated marketing operation, SCANA Energy, which operates in the southeast and includes Georgia’s retail natural gas market. Gas Marketing operating revenues and net income were as follows:

Millions of dollars	**2017**	**2016**	**2015**
Operating revenues	$ 1,001.4	$ 936.7	$ 1,146.7
Net Income	26.9	29.8	27.6

2017 vs 2016

Operating revenues increased primarily due to higher natural gas prices. Net income decreased primarily due to the impact of the remeasurement of deferred income taxes upon enactment of the Tax Act.

2016 vs 2015

Operating revenues decreased due to the lower market price of natural gas and lower industrial sales volume. Net income increased primarily due to a weather-related increase in demand.

Other Operating Expenses

Other operating expenses were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Other operation and maintenance	$ 736.7	$ 755.6	$ 715.3	$ 604.0	$ 613.8	$ 579.4
Impairment loss	1,118.1	—	—	1,118.1	—	—
Depreciation and amortization	381.6	370.9	357.5	311.8	302.2	293.7
Other taxes	264.2	253.9	234.2	246.4	234.7	217.3

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in their respective discussions of operating income (loss). In addition, overall increases in other operating expenses in 2016 were partially offset by the Company's sale of CGT in early 2015, which resulted in decreases in other operation and maintenance expenses of $2.2 million, depreciation and amortization of $0.7 million and other taxes of $0.5 million.

Net Periodic Pension Benefit Cost

Other operation and maintenance expense includes net periodic pension benefit cost, which was recorded on the income statements and balance sheets as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Income Statement Impact:						
Employee benefit costs	$ 15.3	$ 19.2	$ 5.3	$ 12.3	$ 16.4	$ 2.8
Other expense	0.5	0.9	1.1	0.3	0.2	0.2
Balance Sheet Impact:						
Increase in capital expenditures	5.2	5.3	3.9	4.7	4.7	3.4
Component of amount receivable from Summer Station co-owner	2.1	2.1	1.5	2.1	2.1	1.5
Increase (decrease) in regulatory assets	(0.8)	(4.6)	6.2	(0.8)	(4.6)	6.2
Net periodic benefit cost	$ 22.3	$ 22.9	$ 18.0	$ 18.6	$ 18.8	$ 14.1

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were $2.0 million for retail electric operations and $1.0 million for gas operations for each period presented. Pursuant to regulatory orders, PSNC Energy recovers current pension expense through cost of service rates.

Other Income (Expense), net

Other income (expense), net includes the results of certain incidental non-utility activities of regulated subsidiaries, the activities of certain non-regulated subsidiaries, governance activities of the parent company and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. An equity portion of AFC is included in nonoperating income and a debt portion of AFC is included in interest charges (credits), both of which have the effect of increasing reported net income. Components of other income (expense), net were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Other income	$ 78.4	$ 64.4	$ 74.5	$ 44.9	$ 29.3	$ 31.1
Other expense	(46.2)	(38.5)	(60.1)	(24.9)	(24.1)	(31.1)
Gain on sale of SCI, net of transaction costs	—	—	106.6	—	—	—
AFC - equity funds	23.2	29.4	27.0	14.8	26.1	24.8

2017 vs 2016

Other income at the Company and Consolidated SCE&G increased by $10.9 million due to the accrual of carrying costs on unrecovered nuclear project costs and by $6.3 million due to SCPSC-approved carrying cost accrual on certain deferred items. Other expenses at the Company increased primarily due to higher legal costs at the parent company. AFC decreased due to the abandonment of the Nuclear Project and a lower AFC rate as a result of removing Nuclear Project related capital costs from the average construction work in progress balance used to determine the annual AFC rate following the abandonment decision.

2016 vs 2015

Other income at the Company and Consolidated SCE&G decreased by $3.5 million due to lower gains on the sale of land and due to the recognition in 2015 of $5.2 million of gains realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to electric operating revenues and had no effect on net income (see electric margin discussion). At the Company, other income also decreased by $3.9 million and other expenses decreased by $2.3 million due to the sale of SCI, and other income and other expenses decreased by $10.5 million for billings to DECG for transition services provided at cost pursuant to the terms of the sale of CGT. Other expenses at the Company and Consolidated SCE&G decreased by $5.2 million due to lower contribution expenses. In 2015, the Company's other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC increased due to construction activity.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Interest on long-term debt, net	$ 346.7	$ 330.3	$ 311.3	$ 266.1	$ 253.8	$ 236.0
Other interest expense	16.7	12.0	6.5	21.5	16.2	12.1
Total	$ 363.4	$ 342.3	$ 317.8	$ 287.6	$ 270.0	$ 248.1

Interest expense increased in each year primarily due to increased borrowings, and in 2017 due to lower AFC on borrowed funds.

Income Taxes

At the Company, the income tax benefit for 2017 was primarily due to the impairment loss. Additionally, the impact of remeasuring deferred taxes upon enactment of the Tax Act increased deferred tax expense and resulted in additional net loss of approximately $30 million. Exclusive of these items, income tax expense increased from 2016 to 2017 primarily due to higher income before taxes. Income tax expense decreased from 2015 to 2016 primarily due to lower income before taxes. In 2015 income tax expense and income before taxes were affected by the sales of CGT and SCI. At Consolidated SCE&G, income tax expense decreased from 2016 to 2017 primarily due to impacts related to the impairment loss. Without these impacts, income tax expense increased from 2016 to 2017 primarily due to higher income before taxes. Income tax expense increased from 2015 to 2016 primarily due to higher income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Considerations

The Company and Consolidated SCE&G have experienced significant adverse events leading up to their decision to stop construction of Unit 2 and Unit 3, as well as significant adverse events since that decision was made. These events include the bankruptcy filing of the Consortium, the anticipated rejection by the Consortium of the EPC Contract with its fixed-price provisions, and the ongoing contentious proceedings before regulatory and legislative bodies, among others things described in Note 10. In addition, downgrades by credit ratings agencies have occurred since the beginning of 2017, including recent rating actions. The Company and Consolidated SCE&G have significant obligations that must be paid within the next 12 months, including long-term debt maturities and capital lease payments of $727 million for the Company (including $723 million for Consolidated SCE&G), short-term borrowings of $350 million for the Company (including $252 million for Consolidated SCE&G), interest payments of approximately $335 million for the Company (including $259 million for Consolidated SCE&G), and future minimum payments for operating leases of $34 million for the Company (including $26 million for Consolidated SCE&G). Working capital requirements, such as those for fuel supply and similar obligations, also arise due to the lag between when such amounts are paid and when related collection of such costs through customer rates occurs.

Management believes as of the date of issuance of these financial statements that it has access to available sources of cash to pay obligations when due over the next 12 months. These sources include committed lines of credit that expire in December 2018 totaling $200 million for the Company, all of which pertains to Consolidated SCE&G, and committed long-term lines of credit that expire in December 2020 totaling $1.8 billion for the Company (including $1.2 billion for Consolidated SCE&G). In addition, as of the date of issuance of these financial statements, SCE&G continues to collect in customer rates amounts previously approved under the BLRA, as well as amounts provided for in other orders related to non-BLRA electric and gas rates. However, as further described below, SCANA's credit rating has fallen below investment grade, which has constricted its ability and that of Consolidated SCE&G to issue commercial paper.

As described in Note 10, on January 31, 2018, the South Carolina House of Representatives passed a bill (H.4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Such regulatory, legislative or judicial proceedings outside of the Company’s and Consolidated SCE&G’s control may result in the temporary or permanent suspension of the approximately $445 million annually of rates being collected currently under the BLRA, the return of such amounts previously collected of $1.9 billion, or the requirement that SCE&G's share of payments received from the Toshiba Settlement ($1.095 billion) be placed in escrow or be refunded to customers. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

Were the SCPSC to grant the relief sought by ORS in the Request or grant similar relief resulting from legislative action, and as further discussed in Note 10 in the consolidated financial statements, an additional impairment loss or other charges totaling as much as approximately $4.8 billion may be required. Such an impairment loss or other charges would further stress the Company’s and Consolidated SCE&G’s equity to total capitalization ratio and may result in the Company’s and Consolidated SCE&G’s ratio of equity to total capitalization falling below minimum levels prescribed in the Company’s credit agreements. In such an event, the Company’s and Consolidated SCE&G’s ability to borrow under their commercial paper programs and credit facilities and their ability to pay future dividends would likely be limited or may trigger events of default under such agreements.

Known and knowable conditions and events when considered in the aggregate as of the date of issuance of these financial statements do not suggest it is probable that the Company and Consolidated SCE&G will not be able to meet obligations as they come due over the next 12 months. However, possible future actions related to rates or refunds could have a material adverse effect on the Company’s and Consolidated SCE&G’s financial condition, liquidity, results of operations and cash flows such that management’s conclusion with respect to its ability to pay obligations when due could change.

Impact of Abandonment of Nuclear Project

Toshiba provided a parental guaranty for WEC’s payment obligations under the EPC Contract. Following the bankruptcy of WEC, the Toshiba Settlement was executed under which Toshiba was to make periodic settlement payments in the total amount of approximately $2.2 billion ($1.2 billion for SCE&G's 55% share), including certain amounts with respect to contractor liens. In 2017, the first payment under the Toshiba Settlement was received and the remaining amounts due were monetized, resulting in total cash inflows of approximately $2 billion (approximately $1.1 billion for SCE&G's 55% share), including amounts related to the contractor liens. See also Note 10 to the consolidated financial statements. Portions of these proceeds have been utilized to repay maturing commercial paper balances. Such short-term borrowings had been incurred primarily for the construction of Unit 2 and Unit 3 prior to the decision to stop their construction.

Regulatory proceedings being considered by the SCPSC include the Request filed by the ORS which, if granted, would require SCE&G to (1) immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA, and (2) make credits to future bills or refunds to customers for prior revised rates collections in the event that the BLRA is found to be unconstitutional or the South Carolina General Assembly amends or revokes it. SCE&G estimates that revised rates collections, including collections related to transmission assets expected to be placed into service, currently total approximately $445 million annually, and such amounts accumulated as of December 31, 2017 total approximately $1.9 billion.

In an amendment to the Request, the ORS has asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. Parties who filed to intervene in these proceedings or who filed a letter in support of the Request, as amended, include the Governor, the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, the SCEUC, certain large industrial customers, and several environmental groups. On December 20, 2017, the SCPSC denied SCE&G's motion to dismiss the Request and requested that the ORS carry out an inspection, audit and examination of SCE&G's revenue requirements to assist the SCPSC in determining whether SCE&G's present schedule of rates is fair and reasonable and also ordered that a hearing be scheduled to consider the Request. The hearing has not yet been scheduled. See Note 2 for additional developments. SCE&G intends to continue vigorously contesting the Request, but cannot give any assurance as to the timing or outcome of this matter. Any adverse action by the SCPSC, such as that sought by the ORS in the Request, could have a material adverse impact on the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

Should the SCPSC or a court direct that proceeds arising from the Toshiba Settlement be refunded to customers in the near-term, or direct that such funds be escrowed or otherwise made unavailable to SCE&G, it is anticipated that SCE&G would reissue commercial paper, draw on its credit facilities or issue long-term debt to fund such requirement if such sources are available. However, were the SCPSC to rule in favor of the ORS in response to the Request that SCE&G suspend collections from customers of amounts previously authorized under the BLRA, or were other actions of the SCPSC or others taken in order to significantly restrict SCE&G’s access to revenues or impose additional adverse refund obligations on SCE&G, the Company’s and Consolidated SCE&G's assessments regarding the recoverability of all or a portion of the remaining balance of unrecovered nuclear project costs (see Note 2 to the consolidated financial statements) would be adversely impacted and additional impairment losses would likely be recorded. Further, the recognition of significant additional impairment losses with respect to unrecovered Nuclear Project costs could increase the Company’s and Consolidated SCE&G’s debt to total capitalization to a level which may limit their ability to borrow under their commercial paper programs or under their credit facilities and also could constitute a default under these credit facilities. Borrowing costs for long-term debt issuances and access to capital markets could also be negatively impacted.

For additional background on the Nuclear Project and further details on the matters described above, see Note 10 to the consolidated financial statements under Abandoned Nuclear Project - Toshiba Settlement and Subsequent Monetization and Determination to Stop Construction and Related Regulatory, Political and Legal Developments.

In the first quarter of 2017, credit ratings agencies placed SCANA and SCE&G’s credit ratings on negative outlook or watch status due to adverse developments relating to the WEC Bankruptcy. In the third quarter of 2017, two agencies lowered their ratings for SCANA and its rated subsidiaries, citing a decline in the regulatory environment as a principal reason for the downgrades, and both agencies maintained their negative outlook or watch status. On January 3, 2018, after SCANA announced a proposed merger with Dominion Energy, each of the three agencies affirmed or reported no change to their respective credit ratings, and one agency revised its rating outlook for SCANA and its rated operating companies from negative to evolving. However, on January 31, 2018, the South Carolina House of Representatives overwhelmingly approved a bill (H.4375) that, if enacted, would temporarily repeal rates SCE&G collects under the BLRA. As a result, on February 5, 2018, one agency downgraded its ratings for SCANA and SCE&G, and attributed the downgrade to the action taken by the House of Representatives and the politically charged environment that is expected to weigh heavily on any decisions by the SCPSC related to SCE&G's electric rates. With this recent downgrade, the issuer ratings and the senior unsecured debt ratings for SCANA are considered below investment grade by two credit agencies; the issuer ratings for SCE&G are considered to be at the threshold for investment grade by two credit agencies while its senior secured debt ratings remain above investment grade; and the issuer ratings for PSNC Energy are considered to be at the threshold for investment grade by one credit agency while its senior secured debt ratings remain above investment grade. All of the ratings for SCANA, SCE&G and PSNC Energy are either under review for possible downgrade or have a negative or evolving outlook.

Any actions taken by or anticipated to be taken by regulators or legislators that are viewed as adverse, including a change to the BLRA or a requirement that SCE&G make credits to future bills or refunds to customers above such amounts as are included in the Merger Agreement or any requirement that SCE&G make such credits or refunds in the absence of the merger being consummated, or deterioration of the rated companies' commonly monitored financial credit metrics or any additional adverse developments with respect to the Nuclear Project, could further negatively affect their debt ratings. If these rating agencies were to further lower any of these ratings, borrowing costs on new issuances of long-term debt and commercial paper would increase, which could adversely impact financial results or limit or eliminate refinancing opportunities, and the potential pool of investors and funding sources could decrease. In addition, further ratings downgrades may result in lower collateral thresholds being applied to the Company's and Consolidated SCE&G's commodity derivatives, or the removal of such thresholds altogether. This action would have the effect of requiring the Company to post additional collateral for commodity derivative instruments with unfavorable fair values. Ratings downgrades have also resulted in prepayments and demands from vendors for letters of credit, cash deposits, or other forms of credit support under certain gas supply and other agreements, and further ratings downgrades could result in requirements for additional deposits or the provision of additional credit support in order to conduct business under these agreements. See further discussion under the heading Credit Risk Considerations in Note 6 to the consolidated financial statements.

Significant Tax Deductions and Credits

The Company and Consolidated SCE&G have claimed significant research and experimentation tax deductions and credits related to the design and construction activities of Unit 2 and Unit 3. A significant portion of these claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. (See also Note 5 to the consolidated financial statements.) The Company and Consolidated SCE&G also expect to claim a significant tax deduction related to the decision to stop construction and to abandon the Nuclear Project in 2017.

These tax claims primarily involve the timing of recognition of tax deductions rather than permanent tax attributes, and their permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to them, had been deferred within regulatory assets. As such, until December 31, 2017 when it was determined to treat these deferrals as impaired (see Note 10 to the consolidated financial statements), these claims had not had, and were not expected to have in the future, significant direct effects on the Company's and Consolidated SCE&G's results of operations. Nonetheless, the claims have contributed significantly to the Company's and Consolidated SCE&G's cash flows by providing a significant source of capital and lessening the level of debt and equity financing that the Company and Consolidated SCE&G have needed to raise in the financial markets.

The claims made to date are under examination, and are considered controversial, by the IRS. Tax deductions which are expected to be claimed in connection with the determination to abandon the construction of Unit 2 and Unit 3 may also be considered controversial; therefore, it is also expected that the IRS will examine future tax returns. To the extent that any of these claims are not sustained as ordinary losses on examination or through any subsequent appeal, the Company and Consolidated SCE&G will be required to repay any cash received for tax benefit claims which are ultimately disallowed, along with interest on those amounts. Such amounts could be significant and could adversely affect the Company's and Consolidated SCE&G's liquidity, cash flows, results of operations and financial condition. In certain circumstances, which management considers to be remote, penalties for underpayment of income taxes could also be assessed. Additionally, in such circumstances, the Company and Consolidated SCE&G may need to access the capital markets to fund those tax and interest payments, which could in turn adversely impact their ability to access financial markets for other purposes.

Other Liquidity Requirements and Restrictions

The terms of the Merger Agreement place limits on the Company and its subsidiaries as to certain investing and financing transactions. While the Merger Agreement permits the Company and its subsidiaries to refinance and issue certain long-term debt, make capital expenditures at certain levels, consummate certain planned investments, and make regular quarterly dividend payments to its shareholders at certain levels, transactions above these levels would require consent from Dominion Energy, which consent cannot be unreasonably withheld. Permitted transactions include, but are not limited to, the planned refinancing of $710 million of long-term debt maturing in 2018 at Consolidated SCE&G and the planned new issuance of $100 million of long-term debt at PSNC Energy, the purchase of an existing 540-MW gas fired power plant, and the payment by SCANA of regular quarterly dividends to its shareholders subject to certain limits. See Capital Expenditures herein for additional restrictions. In addition, SCANA's Supplementary Key Executive Severance Benefits Plan provides certain payments to qualified senior executive officers in connection with a change in control. In January 2018, approximately $110.7 million was placed irrevocably in a rabbi trust to fund payments pursuant to this and certain other deferred compensation, incentive and retirement plans, which might arise in connection with a change in control and/or a termination of employment or service if and when such payments become due.

The Company expects to meet contractual cash obligations in 2018 through internally generated funds and additional short- and long-term borrowings. Subject to the outcome of the regulatory, legislative and legal proceedings discussed above, the Company expects that, barring a future impairment of the capital markets or its access to such markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for refinancing maturing long-term debt. As noted above, adverse developments in regulatory, legislative or legal proceedings could alter these conclusions.

The terms of the Merger Agreement limit the dividends that SCANA can pay on its shares of common stock to an amount not greater than $0.6125 per share for any quarter. In order to preserve liquidity, the Company may revise its dividend policy to reduce or eliminate dividend payments. Such a decision could result in a significant decrease in the price of SCANA's common stock and an increase in the cost of raising equity capital.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including the legislative and regulatory environment, capital structure and the ability to meet liquidity requirements. As previously noted, adverse developments with respect to recovery of Nuclear Project costs have negatively affected the Company's and Consolidated SCE&G's debt ratings. Further adverse developments, changes in the legislative and regulatory environment or deterioration of SCANA's or its rated operating companies' commonly monitored financial credit metrics could cause the Company and Consolidated SCE&G to pay higher interest rates on its long- and short-term indebtedness, could limit the Company's and Consolidated SCE&G's access to capital markets and liquidity, and could trigger more stringent collateral requirements on interest rate and commodity hedges and under gas supply agreements and other contracts.

Cash provided from operating activities in 2016 and 2017 reflect significant tax benefits (reductions in income tax payments) arising from the deductions previously described under Significant Tax Deductions and Credits. The Company's decision in 2017 to stop construction of Unit 2 and Unit 3 and to abandon the Nuclear Project is expected to result in a significant tax deduction and an associated NOL for tax purposes. The Company expects to obtain a refund of taxes paid in certain prior years as a result of the carryback of the NOL, and expects to benefit from the carryforward of the NOL in future years. These cash flows are expected to supplant portions of financing which would otherwise be obtained in the capital markets.

Enactment of the Tax Act resulted in the remeasurement of deferred income tax assets and liabilities and the recognition as regulatory liabilities of certain excess deferred income taxes (see Note 2 and Note 5 to the consolidated financial statements). These regulatory liabilities will be amortized to the benefit of customers in accordance with the normalization provisions of the IRC and Code of Federal Regulations, which will serve to mitigate significant negative cash impact. Similarly, since the majority of the Company's and Consolidated SCE&G's businesses are rate regulated, lower income taxes payable in future years due to the Tax Act should ultimately result in lower collections from customers in rates.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.2 billion in 2017. Estimates of capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2018	2019
SCE&G		
Generation	$ 124	$ 145
Transmission & Distribution	229	203
Other	12	23
Gas	98	105
Common	3	11
Total SCE&G	466	487
PSNC Energy	288	275
Other	37	24
Total Normal	791	786
Nuclear Fuel - SCE&G	54	51
Total Estimated Capital Expenditures	$ 845	$ 837

Under the terms of the Merger Agreement, the Company may increase the amounts of the above estimated capital expenditures in 2018 and 2019 by not more than 10% without obtaining the consent of Dominion Energy.

Contractual cash obligations as of December 31, 2017 are summarized as follows:

Contractual Cash Obligations	Payments due by periods				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long- and short-term debt, including interest	$ 13,352	$ 1,406	$ 1,721	$ 768	$ 9,457
Capital leases	28	5	14	3	6
Operating leases	112	34	42	9	27
Purchase obligations	3,159	2,345	812	2	—
Other commercial commitments	2,929	1,057	846	258	768
Total	$ 19,580	$ 4,847	$ 3,435	$ 1,040	$ 10,258

As of December 31, 2017, the SCPSC has taken no final action with regard to the Request by the ORS or in connection with the effect of the Tax Act on customer rates, including any action with respect to excess deferred income taxes. Therefore, no amounts have been included in the table above for these matters. See Note 2 to the consolidated financial statements.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty. Purchase obligations also includes amounts related to the EPC Contract, which the Company anticipates that WEC and WECTEC will reject. The Company does not expect that such amounts will be expended. See Note 10 to the consolidated financial statements.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases. The Company has included certain amounts related to nuclear fuel commitments based on its interpretation of its obligations under existing contract terms that are currently disputed by the supplier.

Unrecognized tax benefits of approximately $19 million have been excluded from the table above due to uncertainty as to the timing of any future payments. In addition, the table excludes amounts that may be required to be paid to federal or state taxing authorities related to tax deductions and credits on tax returns for which examinations have not been completed or closed. For additional information, see Note 5 to the consolidated financial statements.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $12.5 million in 2017, and such annual payments are expected to be the same or increase to as much as $16.5 million in the future.

The Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. The Company, including Consolidated SCE&G, is also party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash collateral. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated for accounting purposes as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 6 to the consolidated financial statements. As of December 31, 2017, the Company had posted approximately $29 million in cash collateral related to interest rate derivative contracts.

The Company has a legal obligation associated with the decommissioning and dismantling of Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements. SCE&G's method for funding decommissioning costs is described in Note 1 to the consolidated financial statements.

Financing Limits and Related Matters

Issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018. Were adverse developments to occur with respect to uncertainties highlighted elsewhere, the ability of SCE&G or GENCO to secure renewal of this short-term borrowing authority may be adversely impacted.

At December 31, 2017 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $400 million, $1.2 billion, of which $500 million relates to Fuel Company, and $200 million, respectively, which expire in December 2020. In addition, at December 31, 2017 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2017, the Company had no outstanding borrowings under its credit facilities, had approximately $350 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC-supported letters of credit, and held approximately $409 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. The Company's average short-term borrowings outstanding during 2017 were approximately $870 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2017, the Company’s long-term debt portfolio has a weighted average maturity of approximately 19 years and bears an average cost of 5.75%. Substantially all long-term debt bears fixed interest rates or is swapped to fixed.

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, the terms of the Merger Agreement limit the dividends that SCANA can pay on its shares of common stock to an amount not greater than $0.6125 per share for any quarter.

SCE&G’s bond indenture (relating to the hereinafter defined Bonds) contains provisions that could limit the payment of cash dividends on its common stock. SCE&G's bond indenture permits the payment of dividends on SCE&G's common stock only either (1) out of its Surplus (which as defined equates to its retained earnings) or (2) in case there is no Surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, the Federal

Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2017, approximately $94.0 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

PSNC Energy's note purchase and debenture purchase agreements contain provisions that could limit the payment of cash distributions, including dividends, on PSNC Energy's common stock. These agreements generally limit the sum of distributions to an amount that does not exceed $30 million *plus* 85% of Consolidated Net Income (as therein defined) accumulated after December 31, 2008 *plus* the net proceeds of issuances by PSNC Energy of equity or convertible debt securities (as therein defined). As of December 31, 2017, this limitation would permit PSNC Energy to pay cash distributions in excess of $100 million.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. At December 31, 2017, SCE&G's Unfunded Net Property Additions (which are based on property certified November 30, 2017) totaled approximately $754 million, and the aggregate principal of retired Bonds totaled approximately $491 million. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be issued (Bond Ratio). For the year ended December 31, 2017, the Bond Ratio was 5.24. Adjusted Net Earnings, as therein defined, excludes the impairment loss.

Financing Activities

During 2017, net cash outflows related to financing activities totaled approximately $802 million, primarily associated with short-term borrowings and the payment of dividends. During 2016, net cash inflows related to financing activities totaled approximately $560 million, primarily associated with the proceeds from the issuance of long-term debt and short-term borrowings, partially offset by the payment of dividends.

On November 1, 2016, Consolidated SCE&G paid at maturity $100 million related to a nuclear fuel financing which had an imputed interest rate of 0.78%.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. Also in June 2016, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of the $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2017, PSNC Energy issued $150 million of 4.18% senior notes due June 22, 2047. In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from these sales were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $39 million in 2017, $113 million in 2016, and $253 million, net, in 2015.

For additional information, see Note 4 to the consolidated financial statements.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2017, were as follows:

December 31,	2017	2016	2015	2014	2013
The Company	0.43	3.38	4.40	3.39	3.22
Consolidated SCE&G	(0.10)	3.66	3.69	3.77	3.48

The earnings deficiency below fixed charges for 2017 is approximately $226 million for the Company and approximately $338 million for Consolidated SCE&G. Ratios for 2017 reflect impairment losses related to the Nuclear Project. See Note 10 to the consolidated financial statements. The Company's ratio for 2015 reflects the impact of gains recorded upon the sale of certain subsidiaries. See Note 1 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

The operations of the Company are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on financial condition, results of operations and cash flows. In addition, the conditions or requirements that will be imposed by regulatory or legislative proposals often cannot be predicted. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, recovery of such expenditures and costs are expected through existing ratemaking provisions.

For the three years ended December 31, 2017, capital expenditures for environmental control equipment at fossil fuel generating stations totaled $60.7 million. During this same period, expenditures were made for the construction and retirement of landfills and ash ponds, net of disposal proceeds, of approximately $23.6 million. In addition, expenditures were made to operate and maintain environmental control equipment at fossil plants of $8.2 million in 2017, $9.5 million in 2016 and $8.7 million in 2015, which are included in other operation and maintenance expense, and expenditures were made to handle waste ash, net of disposal proceeds, of $1.2 million in 2017, $2.4 million in 2016 and $1.3 million in 2015, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2017, 2016 and 2015 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $28 million for 2018 and $329 million for the four-year period 2019-2022. These expenditures are included in the Estimated Capital Expenditures table, discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the New Source Review provisions and the NSPS of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to the Company's electric and gas systems, as well as impacts on employees and customers, the supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow for the protection of assets and the return of systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted below. In addition, see Environmental Matters above for a discussion of related regulations to which the Company's operations are subject.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC, under Dodd-Frank, concerning record keeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCANA and any of its subsidiaries engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and other matters, including accounting; the DOE under the Federal Power Act as to use of emergency authority and coordination of all applicable federal authorizations and related environmental reviews to site an electric transmission facility; and the NRC with respect to the ownership, construction, operation and decommissioning of its nuclear facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings); the FERC as to issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters; and the DOE under the Federal Power Act as to use of emergency authority.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.
SCE&G and PSNC Energy	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively. The ORS and the NCUC as to enforcement of federal and state pipeline safety requirements in South Carolina (SCE&G) and North Carolina (PSNC Energy), respectively. The FERC as to participation in wholesale natural gas markets.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract. The FERC as to participation in wholesale natural gas markets.

Material retail rate proceedings, and significant uncertainties with respect to certain of these proceedings, are described in Note 2 and Note 10 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system and certain facilities related to generation and distribution are subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and the CFTC and the SEC continue to modify the implementation of Dodd-Frank through rule makings. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Impairment Considerations

Under the current regulatory construct in South Carolina, pursuant to the BLRA or through other means, the ability of SCE&G to recover costs incurred in connection with Unit 2 and Unit 3, and a reasonable return on them, will be subject to review and approval by the SCPSC. In light of the contentious nature of the reviews by legislative committees and others, the adverse impact that would result if proposed legislation is enacted, and the Request being considered by the SCPSC that could result in the suspension of rates currently being collected under the BLRA, as well as the return of such amounts previously collected, there is significant uncertainty as to SCE&G's ultimate ability to fully recover its costs of Unit 2 and Unit 3 and a return on them from its customers. SCE&G continues to contest the specific challenges set forth in regulatory, legislative and legal proceedings (see also Note 10 to the consolidated financial statements). However, based on the consideration of those challenges, and particularly in light of SCE&G's proposed solution announced on November 16, 2017 and details in the Joint Petition filed by SCE&G and Dominion Energy with the SCPSC on January 12, 2018, the Company and Consolidated SCE&G have determined that a disallowance of recovery of part of the cost of the abandoned plant is both probable and reasonably estimable under applicable accounting guidance. In addition, the Company and Consolidated SCE&G have determined that recovery of certain other related costs deferred within regulatory assets is less than probable. As a result, as of December 31, 2017, the Company and Consolidated SCE&G have recognized a pre-tax impairment loss totaling $1.118 billion ($690 million net of tax). With the exception of the $210 million loss recorded in the third quarter of 2017 as explained below, this impairment loss was recorded in the fourth quarter of 2017. A discussion of this impairment loss follows:

- A pre-tax impairment loss was recorded with respect to disallowance of unrecovered nuclear project costs of approximately $670 million. This amount includes $210 million recorded in the third quarter of 2017, which represented costs of approximately $1.2 billion that had been expended on the project, exclusive of transmission costs, but which had not yet been determined to be prudent by the SCPSC in connection with revised rates proceedings under the BLRA, offset by the amount of approximately $1 billion, which amount represents the recovery of the Toshiba Settlement proceeds that are in excess of amounts from that settlement that the Company and Consolidated SCE&G estimated may be necessary to satisfy certain project liens. This impairment loss also includes $180 million, which amount arises from SCE&G's entry into an agreement in the fourth quarter of 2017 to purchase in 2018 an existing 540-MW combined cycle gas generating station along with SCE&G's commitment to regulators and the public that the recovery of the initial capital investment in the facility would not be sought from customers. The remaining $280 million of this impairment loss was recorded after consideration of the regulatory and political developments in the fourth quarter of 2017 and early 2018 described in Note 10 to the consolidated financial statements.
- A pre-tax impairment loss was recorded in the aggregate amount of $361 million to write off costs which had been previously deferred, primarily as regulatory assets, in connection with the Nuclear Project. Such regulatory assets included deferred losses on interest rate swaps for which debt will not be issued due to the abandonment of the Nuclear Project, carrying costs on deferred tax assets arising from the capitalization of interest costs for tax purposes, net deferred costs and tax benefits related to foregone domestic production activities deductions (net of uncertain tax positions and credits) taken with respect to the project, and taxes associated with equity AFC.
- Finally, an $87 million pre-tax impairment loss was recorded in order to reduce to estimated fair value the carrying value of nuclear fuel acquired for use in Unit 2 and Unit 3.

With the exception of the $87 million related to nuclear fuel, the above impairment loss reflects impacts similar to those that may have resulted had the proposed solution announced November 16, 2017 been implemented. That proposal is presented by SCE&G as a less-favored alternative to the merger benefits and cost recovery plan in the January 12, 2018 Joint Petition. It is reasonably possible that a change in the estimated impairment loss could occur in the near term. If the merger benefits and cost recovery plan outlined in the Joint Petition is implemented (upon closing of the merger as contemplated in the Merger Agreement), an additional impairment loss and other charges totaling as much as approximately $1.7 billion would be expected to be recorded. This additional impairment loss would result from the write-off of unrecovered Nuclear Project costs of approximately $856 million recorded within regulatory assets and the recording of additional liabilities for customer refunds totaling approximately $1.875 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. If instead the Joint Petition is not approved and the Request by the ORS is approved, and if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, the Company and Consolidated SCE&G may be required to record an additional impairment loss and other charges totaling as much as approximately $4.8 billion. This additional impairment loss would result from the write-off of the remaining unrecovered Nuclear Project costs of $3.976 billion recorded within regulatory assets and the refund of revised rates collections under the BLRA described above of approximately $1.9 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens.

Accounting for Rate Regulated Operations

Regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the criteria of accounting for rate-regulated utilities may no longer be met, and the write off of regulatory assets and liabilities could be required. Such an event could have a material effect on the results of operations, liquidity or financial position of the Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the regulatory assets and liabilities.

Generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write down in those assets could be required. It is not possible to predict whether any write-downs would be necessary and, if they were, the extent to which they would affect results of operations in the period in which they would be recorded. As of December 31, 2017, net investments in fossil/hydro and nuclear generation assets (excluding assets associated with the Nuclear Project, which are discussed under Impairment Considerations above) were approximately $2.2 billion and $825 million, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, estimates are recorded for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. The Company's accounts receivable included unbilled revenues of $220.9 million at December 31, 2017 and $178.9 million at December 31, 2016, compared to total revenues of $4.4 billion in 2017 and $4.2 billion in 2016. See Note 1 to the consolidated financial statements for a discussion of the impact expected from the adoption of new revenue recognition guidance in 2018.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G’s accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates, less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The asset balance held in the trust reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Asset Retirement Obligations

AROs are accrued for legal obligations associated with the retirement of long-lived tangible assets that result from acquisition, construction, development and normal operation in accordance with applicable accounting guidance. These obligations are recognized at present value in the period in which they are incurred, and associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2017, the Company has recorded AROs of $208 million for nuclear plant decommissioning (as discussed above) and AROs of $360 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of precision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as a liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $22.3 million recorded in 2017 reflects the use of a 4.22% discount rate derived using a cash flow matching technique, and an assumed 7.25% long-term rate of return on plan assets. The Company believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2017 would have increased the Company’s pension cost by $1.7 million and increased the pension obligation by $25.2 million. Further, had the assumed long-term rate of return on assets been 7.00%, the Company’s pension cost for 2017 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2017, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.1%, 5.4%, 6.9% and 8.2%, respectively. The 2017 expected long-term rate of return of 7.25% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2018, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.1%, 7.8%, 6.6% and 8.5%, respectively. For 2018, it is anticipated that the long-term expected rate of return will be 7.00%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's and PSNC Energy's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after 2023. As a result, the significance of pension costs and the criticality of the related estimates will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future based on current market conditions and assumptions.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.30%, derived using a cash flow matching technique, and recorded a net cost for 2017 of $17.0 million. Had the selected discount rate been 4.05% (25 basis points lower than the discount rate referenced above), the expense for 2017 would have been $0.6 million higher and the obligation would have increased by $8.6 million. Because the plan provisions include “caps” on company per capita costs, and because employees hired after 2010 are responsible for the full cost of retiree medical benefits elected by them, health care cost inflation rate assumptions do not materially impact the net expense recorded.

Uncertain Income Tax Positions

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In 2016 and 2017, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the design and construction activities of the Nuclear Project, in its 2015 and 2016 income tax returns. SCANA expects to claim similar deductions and credits on its 2017 tax return when it is filed in 2018. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. See also Note 5 to the consolidated financial statements.

These IRC Section 174 income tax deductions and IRC Section 41 credits were considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities were recorded as unrecognized tax benefits in the financial statements. Following the abandonment of the Nuclear Project, SCANA anticipates that an abandonment loss deduction under IRC Section 165 will be claimed on the 2017 tax return. As such, certain of the IRC Section 174 deductions, to the extent they are denied, would instead be deductible in 2017 under IRC Section 165. The abandonment loss deduction is also considered an uncertain tax position; however, under relevant accounting guidance, no such estimated unrecognized tax benefits were recorded as of December 31, 2017. The remaining unrecognized tax benefits include the impact of the IRC Section 174 deductions on domestic production activities deductions, credits, and certain unrecognized state tax benefits.

As of December 31, 2017, the Company and Consolidated SCE&G have recorded an unrecognized tax benefit of $98 million ($19 million net of the impact of state deductions on federal returns, net of NOLs and credit carryforwards, and net of receivables related to the uncertain tax positions). If recognized, $98 million of the tax benefit would affect the Company's and Consolidated SCE&G's effective tax rates. These unrecognized tax benefits are not expected to increase significantly within the next 12 months. It is also reasonably possible that these unrecognized tax benefits may decrease by $11 million within the next 12 months. No other material changes in the status of the Company's or Consolidated SCE&G's tax positions have occurred through December 31, 2017.

The estimates of unrecognized tax benefits were computed with consideration as to whether the claims are (or are not) more likely than not to be sustained and with consideration of analyses of cumulative probabilities regarding potential outcomes. Such estimates involve significant management judgment and varying levels of precision. Changes in such estimates are required to be recorded as circumstances change and additional information regarding the claims and potential outcomes becomes available, and these changes could be significant.

Historically, because the unrecognized tax benefit through December 31, 2017 primarily involved the timing of recognition of tax deductions rather than permanent tax attributes, the estimates regarding their recognition did not have a significant impact on the Company's effective tax rate. Further, until December 31, 2017, when such deferrals were considered to be less than probable of recovery (see Note 10), these permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to the unrecognized tax benefits, had been deferred within regulatory assets. As such, the impacts of these significant accounting estimates, and changes therein, had primarily been reflected on the balance sheet rather than in results of operations. In the future, the impact of changes in estimates with respect to these permanent attributes (net) are not expected to be deferred within regulatory assets (see Note 10) and the impact of such changes to the unrecognized tax benefit related to these permanent attributes (net) could be significant.

Upon resolution of the uncertainties, the Company will be required to re-pay any tax benefits claimed which are ultimately disallowed, along with interest on those amounts. In certain circumstances, which the Company considers to be remote, penalties for underpayment of income taxes could also be assessed. Such re-payment amounts could be significant and adversely affect cash flow and financial condition.

OTHER MATTERS

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. The Company does not engage in significant off-balance sheet financing or similar transactions, although it is party to various operating leases in the normal course of business for land, office space, furniture, equipment, rail cars, a purchase power agreement, and airplanes.

Claims and Litigation

For a description of claims and litigation, see Note 10 to the consolidated financial statements.

Other

As Georgia's regulated provider, SCANA Energy provides service to customers considered to be low-income or that are otherwise unable to obtain natural gas service from other marketers. SCANA Energy provides this service at rates approved by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA's natural gas distribution and gas marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating natural gas commodity prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or placed under contract.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provide information about long-term debt issued by the Company and Consolidated SCE&G and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

The Company

December 31, 2017	**Expected Maturity Date**							
Millions of dollars	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	722.5	12.0	361.5	490.2	259.3	4,683.9	6,529.4	7,261.8
Average Fixed Interest Rate (%)	6.01	4.31	6.31	4.63	5.26	5.71	5.68	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	120.6	142.6	137.8
Average Variable Interest Rate (%)	2.18	2.18	2.18	2.18	2.18	1.64	1.72	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	554.4	4.4	4.4	4.4	4.4	124.2	696.2	20.4
Average Pay Interest Rate (%)	2.14	6.17	6.17	6.17	6.17	4.51	2.66	—
Average Receive Interest Rate (%)	1.48	2.18	2.18	2.18	2.18	1.91	1.58	—

December 31, 2016	**Expected Maturity Date**							
Millions of dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	12.5	721.7	11.1	360.2	489.0	4,789.7	6,384.3	7,040.6
Average Fixed Interest Rate (%)	4.21	6.01	4.40	6.33	4.64	5.73	5.70	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	125.0	147.0	142.7
Average Variable Interest Rate (%)	1.63	1.63	1.63	1.63	1.63	1.16	1.23	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	554.4	704.4	4.4	4.4	4.4	128.6	1,400.6	12.3
Average Pay Interest Rate (%)	2.91	2.22	6.17	6.17	6.17	4.57	2.74	—
Average Receive Interest Rate (%)	1.00	1.00	1.63	1.63	1.63	1.08	1.02	—

Consolidated SCE&G

December 31, 2017	Expected Maturity Date							
Millions of dollars	2018	2019	2020	2021	2022	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	722.5	12.0	11.5	40.2	9.3	4,333.9	5,129.4	5,726.8
Average Fixed Interest Rate (%)	6.01	4.31	4.38	3.58	4.74	5.76	5.77	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	63.5
Average Variable Interest Rate (%)	—	—	—	—	—	1.21	1.21	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	550.0	—	—	—	—	71.4	621.4	37.4
Average Pay Interest Rate (%)	2.10	—	—	—	—	3.29	2.24	—
Average Receive Interest Rate (%)	1.48	—	—	—	—	1.71	1.51	—

December 31, 2016	Expected Maturity Date							
Millions of dollars	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	12.0	721.7	11.1	10.2	39.0	4,339.7	5,133.7	5,687.3
Average Fixed Interest Rate (%)	4.27	6.01	4.40	4.54	3.60	5.75	5.76	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	64.9
Average Variable Interest Rate (%)	—	—	—	—	—	0.76	0.76	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	550.0	700.0	—	—	—	71.4	1,321.4	31.7
Average Pay Interest Rate (%)	2.88	2.19	—	—	—	3.29	2.54	—
Average Receive Interest Rate (%)	1.00	1.00	—	—	—	0.64	0.98	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of long-term debt and interest rate derivatives, see the Liquidity and Capital Resources section in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 4 and Note 6 to the consolidated financial statements.

Commodity Price Risk

The following table provides information about the Company's financial instruments, which are limited to financial positions of Energy Marketing and PSNC Energy, that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	2018	2019	2020
Futures - Long			
Settlement Price (a)	2.87	2.94	—
Contract Amount (b)	53.1	13.3	—
Fair Value (b)	49.8	13.0	—
Futures - Short			
Settlement Price (a)	2.85	—	—
Contract Amount (b)	5.6	—	—
Fair Value (b)	5.1	—	—
Options - Purchased Call (Long)			
Strike Price (a)	3.35	—	—
Contract Amount (b)	20.7	—	—
Fair Value (b)	0.7	—	—
Swaps - Commodity			
Pay fixed/receive variable (b)	15.9	6.7	3.0
Average pay rate (a)	3.2293	2.9298	2.8730
Average received rate (a)	2.8587	2.8613	2.8211
Fair Value (b)	14.1	6.5	2.9

Pay variable/receive fixed (b)	29.6	11.5	2.7
Average pay rate (a)	2.8505	2.8710	2.8211
Average received rate (a)	3.0993	2.9410	2.8764
Fair Value (b)	32.2	11.8	2.8
Swaps - Basis			
Pay variable/receive variable (b)	7.0	0.3	—
Average pay rate (a)	2.8191	3.0876	—
Average received rate (a)	2.7935	3.0306	—
Fair Value (b)	7.0	0.3	—

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), changes in common equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedule listed in the Part IV at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Emphasis of Matter

As discussed in Note 10 to the financial statements, the abandoned Nuclear Project has led to legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

We have served as the Company's auditor since 1945.

SCANA Corporation and Subsidiaries
Consolidated Balance Sheets

December 31, (Millions of dollars)	2017	2016
Assets		
Utility Plant In Service	$ 14,370	$ 13,444
Accumulated Depreciation and Amortization	(4,611)	(4,446)
Construction Work in Progress	471	4,845
Nuclear Fuel, Net of Accumulated Amortization	208	271
Goodwill	210	210
Utility Plant, Net	10,648	14,324
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $133 and $138	270	276
Assets held in trust, net-nuclear decommissioning	136	123
Other investments	68	76
Nonutility Property and Investments, Net	474	475
Current Assets:		
Cash and cash equivalents	409	208
Receivables:		
Customer, net of allowance for uncollectible accounts of $6 and $6	665	616
Income taxes	198	142
Other	105	127
Inventories:		
Fuel	143	136
Materials and supplies	161	155
Prepayments	99	105
Other current assets	17	17
Derivative financial instruments	54	—
Total Current Assets	1,851	1,506
Deferred Debits and Other Assets:		
Regulatory assets	5,580	2,130
Other	186	272
Total Deferred Debits and Other Assets	5,766	2,402
Total	$ 18,739	$ 18,707

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2017	2016
Capitalization and Liabilities		
Common Stock - no par value, 143 million shares outstanding for all periods presented	$ 2,390	$ 2,390
Retained Earnings	2,915	3,384
Accumulated Other Comprehensive Loss	(50)	(49)
Total Common Equity	5,255	5,725
Long-Term Debt, Net	5,906	6,473
Total Capitalization	11,161	12,198
Current Liabilities:		
Short-term borrowings	350	941
Current portion of long-term debt	727	17
Accounts payable	438	404
Customer deposits and customer prepayments	112	168
Taxes accrued	214	201
Interest accrued	87	84
Dividends declared	86	80
Derivative financial instruments	6	35
Other	93	135
Total Current Liabilities	2,113	2,065
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,261	2,159
Asset retirement obligations	568	558
Pension and postretirement benefits	360	373
Unrecognized tax benefits	19	219
Regulatory liabilities	3,059	930
Other	198	205
Total Deferred Credits and Other Liabilities	5,465	4,444
Commitments and Contingencies (Note 10)	—	—
Total	$ 18,739	$ 18,707

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Operations

Years Ended December 31, (Millions of dollars, except per share amounts)	2017	2016	2015
Operating Revenues:			
Electric	$ 2,659	$ 2,614	$ 2,551
Gas-regulated	874	788	811
Gas-nonregulated	874	825	1,018
Total Operating Revenues	4,407	4,227	4,380
Operating Expenses:			
Fuel used in electric generation	594	576	660
Purchased power	80	64	52
Gas purchased for resale	1,156	1,054	1,287
Other operation and maintenance	737	755	715
Impairment loss	1,118	—	—
Depreciation and amortization	382	371	358
Other taxes	264	254	234
Total Operating Expenses	4,331	3,074	3,306
Gain on sale of CGT, net of transaction costs	—	—	234
Operating Income	76	1,153	1,308
Other Income (Expense), net	56	55	42
Gain on sale of SCI, net of transaction costs	—	—	107
Interest charges, net of allowance for borrowed funds used during construction of $18, $19 and $15	(363)	(342)	(318)
Income (Loss) Before Income Tax Expense	(231)	866	1,139
Income Tax Expense (Benefit)	(112)	271	393
Net Income (Loss)	$ (119)	$ 595	$ 746
Earnings (Loss) Per Share of Common Stock	$ (0.83)	$ 4.16	$ 5.22
Weighted Average Common Shares Outstanding (millions)	143	143	143
Dividends Declared Per Share of Common Stock	$ 2.45	$ 2.30	$ 2.18

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)

Years Ended December 31, (Millions of dollars)	2017	2016	2015
Net Income (Loss)	$ (119)	$ 595	$ 746
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $(4), $2 and $(7)	(7)	4	(12)
Cash flow hedging activities reclassified to interest expense, net of tax of $4, $4 and $4	7	7	7
Cash flow hedging activities reclassified to gas purchased for resale, net of tax of $-, $4 and $9	(1)	6	15
Net unrealized gains (losses) on cash flow hedging activities	(1)	17	10
Deferred Costs of Employee Benefit Plans:			
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	—	(1)	—
Net deferred costs of employee benefit plans	—	(1)	—
Other Comprehensive Income (Loss)	(1)	16	10
Total Comprehensive Income (Loss)	$ (120)	$ 611	$ 756

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2017	2016	2015
Cash Flows From Operating Activities:			
Net Income (Loss)	$ (119)	$ 595	$ 746
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain on sale of subsidiaries	—	—	(355)
Impairment loss	1,118	—	—
Deferred income taxes, net	(911)	242	(31)
Depreciation and amortization	406	389	368
Amortization of nuclear fuel	44	57	46
Allowance for equity funds used during construction	(23)	(29)	(27)
Carrying cost recovery	(34)	(17)	(12)
Changes in certain assets and liabilities:			
Receivables	(56)	(112)	188
Income tax receivable	(56)	(142)	—
Inventories	(93)	(43)	(16)
Prepayments	(5)	11	211
Regulatory assets	181	(114)	(31)
Regulatory liabilities	1,051	(2)	(1)
Accounts payable	24	44	(78)
Unrecognized tax benefits	(224)	175	31
Taxes accrued	13	(41)	61
Pension and other postretirement benefits	(20)	51	(6)
Derivative financial instruments	(3)	(9)	(9)
Other assets	(47)	(44)	(3)
Other liabilities	(77)	81	(23)
Net Cash Provided From Operating Activities	1,169	1,092	1,059
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,225)	(1,579)	(1,153)
Proceeds from sale of subsidiaries	—	—	647
Proceeds from guaranty settlement	1,096	—	—
Proceeds from investments (including derivative collateral returned)	145	860	1,117
Purchase of investments (including derivative collateral posted)	(143)	(788)	(1,018)
Payments upon interest rate derivative contract settlement	(39)	(113)	(263)
Proceeds from interest rate derivative contract settlement	—	—	10
Net Cash Used For Investing Activities	(166)	(1,620)	(660)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	—	—	14
Proceeds from issuance of long-term debt	150	592	491
Repayments of long-term debt	(17)	(117)	(166)
Dividends	(344)	(325)	(309)
Short-term borrowings, net	(591)	410	(387)
Deferred financing costs	—	—	(3)
Net Cash Provided From (Used For) Financing Activities	(802)	560	(360)
Net Increase in Cash and Cash Equivalents	201	32	39
Cash and Cash Equivalents, January 1	208	176	137
Cash and Cash Equivalents, December 31	$ 409	$ 208	$ 176
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $18, $19 and $15)	$ 346	$ 328	$ 306
—Income taxes paid	2	229	184
—Income taxes received	184	166	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures (including nuclear fuel)	139	109	244
Capital leases	8	15	6

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Changes in Common Equity

	Common Stock				Accumulated Other Comprehensive Income (Loss)			
Millions	Shares	Outstanding Amount	Treasury Amount	Retained Earnings	Gains (Losses) on Cash Flow Hedges	Deferred Costs of Employee Benefit Plans	Total AOCI	Total
Balance as of January 1, 2015	143	$ 2,388	$ (10)	$ 2,684	$ (63)	$ (12)	$ (75)	$ 4,987
Net Income				746				746
Other Comprehensive Income (Loss)								
Losses arising during the period					(12)	—	(12)	(12)
Losses/amortization reclassified from AOCI					22	—	22	22
Total Comprehensive Income (Loss)				746	10	—	10	756
Issuance of Common Stock	—	14	(2)					12
Dividends Declared				(312)				(312)
Balance as of December 31, 2015	143	$ 2,402	(12)	3,118	(53)	(12)	(65)	5,443
Net Income				595				595
Other Comprehensive Income (Loss)								
Gains (Losses) arising during the period					4	(1)	3	3
Losses/amortization reclassified from AOCI					13	—	13	13
Total Comprehensive Income				595	17	(1)	16	611
Dividends Declared				(329)				(329)
Balance as of December 31, 2016	143	$ 2,402	(12)	3,384	(36)	(13)	(49)	5,725
Net Loss				(119)				(119)
Other Comprehensive Income (Loss)								
Losses arising during the period					(7)	—	(7)	(7)
Losses/amortization reclassified from AOCI					6	—	6	6
Total Comprehensive Income (Loss)				(119)	(1)	—	(1)	(120)
Dividends Declared				(350)				(350)
Balance as of December 31, 2017	143	$ 2,402	$ (12)	$ 2,915	$ (37)	$ (13)	$ (50)	$ 5,255

Dividends declared per share of common stock were $2.45, $2.30 and $2.18 for 2017, 2016 and 2015, respectively.

See Notes to Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of comprehensive income (loss), changes in equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedule listed in the Part IV at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Emphasis of Matter

As discussed in Note 10 to the financial statements, the abandoned Nuclear Project has led to legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

We have served as the Company's auditor since 1945.

South Carolina Electric & Gas Company and Affiliates
Consolidated Balance Sheets

December 31, (Millions of dollars)	2017	2016
Assets		
Utility Plant In Service	$ 12,161	$ 11,510
Accumulated Depreciation and Amortization	(4,124)	(3,991)
Construction Work in Progress	375	4,813
Nuclear Fuel, Net of Accumulated Amortization	208	271
Utility Plant, Net ($711 and $756 related to VIEs)	8,620	12,603
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	71	69
Assets held in trust, net-nuclear decommissioning	136	123
Other investments	2	3
Nonutility Property and Investments, Net	209	195
Current Assets:		
Cash and cash equivalents	395	164
Receivables:		
Customer, net of allowance for uncollectible accounts of $4 and $3	390	378
Affiliated companies	32	16
Income taxes	198	53
Other	85	94
Inventories:		
Fuel	90	83
Materials and supplies	149	143
Prepayments	82	88
Derivative financial instrument	54	—
Other current assets	2	1
Total Current Assets ($191 and $85 related to VIEs)	1,477	1,020
Deferred Debits and Other Assets:		
Regulatory assets	5,476	2,030
Other	164	243
Total Deferred Debits and Other Assets ($50 and $52 related to VIEs)	5,640	2,273
Total	$ 15,946	$ 16,091

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2017	2016
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,860	$ 2,860
Retained Earnings	1,982	2,481
Accumulated Other Comprehensive Loss	(4)	(3)
Total Common Equity	4,838	5,338
Noncontrolling interest	142	134
Total Equity	4,980	5,472
Long-Term Debt, net	4,441	5,154
Total Capitalization	9,421	10,626
Current Liabilities:		
Short-term borrowings	252	804
Current portion of long-term debt	723	12
Accounts payable	251	247
Affiliated payables	102	122
Customer deposits and customer prepayments	70	126
Taxes accrued	208	195
Interest accrued	67	68
Dividends declared	82	79
Derivative financial instruments	2	28
Other	47	55
Total Current Liabilities	1,804	1,736
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,173	1,939
Asset retirement obligations	529	522
Pension and postretirement benefits	217	232
Unrecognized tax benefits	19	236
Regulatory liabilities	2,667	695
Other	97	89
Other - affiliate	19	16
Total Deferred Credits and Other Liabilities	4,721	3,729
Commitments and Contingencies (Note 10)	—	—
Total	$ 15,946	$ 16,091

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Comprehensive Income (Loss)

For the Years Ended December 31, (Millions of dollars)	2017	2016	2015
Operating Revenues:			
Electric	$ 2,659	$ 2,614	$ 2,551
Electric - nonconsolidated affiliate	5	5	6
Gas	405	366	372
Gas - nonconsolidated affiliate	1	1	1
Total Operating Revenues	3,070	2,986	2,930
Operating Expenses:			
Fuel used in electric generation	465	472	559
Fuel used in electric generation - nonconsolidated affiliate	129	104	102
Purchased power	80	64	52
Gas purchased for resale	206	174	162
Gas purchased for resale - nonconsolidated affiliate	—	9	31
Other operation and maintenance	417	403	380
Other operation and maintenance - nonconsolidated affiliate	187	211	199
Impairment loss	1,118	—	—
Depreciation and amortization	312	302	294
Other taxes	241	227	211
Other taxes - nonconsolidated affiliate	5	7	6
Total Operating Expenses	3,160	1,973	1,996
Operating Income (Loss)	(90)	1,013	934
Other Income (Expense), net	35	31	25
Interest charges, net of allowance for borrowed funds used during construction of $15, $18 and $14	(288)	(270)	(248)
Income (Loss) Before Income Tax Expense	(343)	774	711
Income Tax Expense (Benefit)	(171)	248	231
Net Income (Loss) and Total Comprehensive Income (Loss)	(172)	526	480
Less Net Income and Total Comprehensive Income Attributable to Noncontrolling Interest	13	13	14
Earnings (Loss) and Comprehensive Income Available (Loss Attributable) to Common Shareholder	$ (185)	$ 513	$ 466
Dividends Declared on Common Stock	$ 323	$ 305	$ 285

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Cash Flow

For the Years Ended December 31, (Millions of dollars)	2017	2016	2015
Cash Flows From Operating Activities:			
Net income (Loss)	$ (172)	$ 526	$ 480
Adjustments to reconcile net income to net cash provided from operating activities:			
Impairment loss	1,118	—	—
Deferred income taxes, net	(780)	207	8
Depreciation and amortization	323	310	294
Amortization of nuclear fuel	44	57	46
Allowance for equity funds used during construction	(15)	(26)	(25)
Carrying cost recovery	(34)	(17)	(12)
Changes in certain assets and liabilities:			
Receivables	(32)	(47)	85
Receivables - affiliate	12	(3)	16
Income tax receivable	(145)	(53)	—
Inventories	(60)	(35)	(24)
Prepayments	6	(4)	70
Regulatory assets	185	(94)	(29)
Other regulatory liabilities	899	(5)	(3)
Accounts payable	20	8	11
Accounts payable - affiliate	(28)	13	(17)
Unrecognized tax benefits	(241)	192	31
Taxes accrued	13	(104)	129
Pension and other postretirement benefits	(21)	39	(5)
Other assets	(46)	(99)	57
Other liabilities	(43)	58	(28)
Other liabilities - affiliate	3	(1)	(6)
Net Cash Provided From Operating Activities	1,006	922	1,078
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(928)	(1,399)	(1,008)
Proceeds from guaranty settlement	1,096	—	—
Proceeds from investments and sales of assets (including derivative collateral returned)	118	794	975
Purchase of investments (including derivative collateral posted)	(122)	(740)	(887)
Payments upon interest rate derivative contract settlement	(39)	(113)	(263)
Proceeds from interest rate derivative contract settlement	—	—	10
Proceeds from investment in affiliate	—	9	71
Investment in affiliate	(28)	—	—
Net Cash Used For Investing Activities	97	(1,449)	(1,102)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	—	494	491
Repayment of long-term debt	(12)	(112)	(11)
Dividends	(319)	(301)	(285)
Short-term borrowings, net	(552)	384	(289)
Short-term borrowings-nonconsolidated affiliate, net	8	(4)	(50)
Contribution from parent	3	100	204
Return of capital to parent	—	—	(4)
Deferred financing costs	—	—	(2)
Net Cash Provided From Financing Activities	(872)	561	54
Net Increase in Cash and Cash Equivalents	231	34	30
Cash and Cash Equivalents, January 1	164	130	100
Cash and Cash Equivalents, December 31	$ 395	$ 164	$ 130
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $15, $18 and $14)	$ 269	$ 251	$ 228
—Income taxes paid	47	289	89
—Income taxes received	145	189	84
Noncash Investing and Financing Activities:			
Accrued construction expenditures (including nuclear fuel)	99	95	230

Capital leases	8	14	6

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Changes in Equity

Millions	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total Equity
Balance at January 1, 2015	40	$ 2,560	$ 2,077	$ (3)	$ 123	$ 4,757
Earnings available for common shareholder			466		14	480
Deferred cost of employee benefit plans, net of tax $-				—		—
Total Comprehensive Income			466	—	14	480
Capital contributions from parent		200			—	200
Cash dividends declared			(278)		(8)	(286)
Balance at December 31, 2015	40	2,760	2,265	(3)	129	5,151
Earnings Available for Common Shareholder			513		13	526
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			513	—	13	526
Capital contributions from parent		100			—	100
Cash dividends declared			(297)		(8)	(305)
Balance at December 31, 2016	40	2,860	2,481	(3)	134	5,472
Earnings (Loss) Available for (Attributable to) Common Shareholder			(185)		13	(172)
Deferred Cost of Employee Benefit Plans, net of tax $-				(1)		(1)
Total Comprehensive Income (Loss)			(185)	(1)	13	(173)
Capital contributions from parent		—			3	3
Cash dividends declared			(314)		(8)	(322)
Balance at December 31, 2017	40	$ 2,860	$ 1,982	$ (4)	$ 142	$ 4,980

See Notes to Consolidated Financial Statements.

The following notes to the consolidated financial statements are a combined presentation. Except as otherwise indicated herein, each note applies to the Company and Consolidated SCE&G; however, Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation or its subsidiaries (other than Consolidated SCE&G).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

The Company

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina, the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia and conducts other energy-related business.

The accompanying consolidated financial statements reflect the accounts of SCANA, the following wholly-owned subsidiaries, and subsidiaries that formerly were wholly-owned during the periods presented.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	SCANA Services, Inc.
South Carolina Generating Company, Inc.	SCANA Corporate Security Services, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Communications Holdings, Inc.

SCANA reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance. Discussions regarding the Company's financial results necessarily include the results of Consolidated SCE&G.

Consolidated SCE&G

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs) and accordingly, Consolidated SCE&G's consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G’s parent. As a result, GENCO’s and Fuel Company’s equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G’s consolidated financial statements.

GENCO owns a coal-fired electric generating station with a 605 MW net generating capacity (summer rating). GENCO’s electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO’s property (carrying value of approximately $503 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G’s nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Dispositions

In the first quarter of 2015, SCANA sold CGT and SCI. CGT was an interstate natural gas pipeline regulated by FERC that transported natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provided fiber optic communications and other services and built, managed and leased communications towers in several southeastern states, and it was sold to Spirit Communications. These sales resulted in recognition of pre-tax gains totaling approximately $342 million. The pre-tax gain from the sale of CGT is included within Operating Income and the pre-tax gain from the sale of SCI is included within Other Income (Expense) on the Company's consolidated statement of operations.

CGT and SCI operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment. The sales of CGT and SCI did not represent a strategic shift that had a major effect on the Company's operations; therefore, these sales did not meet the criteria for classification as discontinued operations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

No estimate is made for legal costs expected to be incurred in connection with loss contingencies. Such costs are recorded when incurred.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset’s life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company’s regulated subsidiaries calculated AFC using average composite rates of 5.6% for 2017, 5.3% for 2016, and 6.1% for 2015. Consolidated SCE&G calculated AFC using average composite rates of 3.9% for 2017, 4.7% for 2016, and 5.6% for 2015. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property, and in most cases, include provisions for future cost of removal. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. In addition, CGT was sold in the first quarter of 2015 (see Dispositions herein) and excluded from the 2015 calculation of composite weighted average depreciation rates. The composite weighted average depreciation rates for utility plant assets were as follows:

	2017	2016	2015
SCE&G	2.55%	2.56%	2.55%
GENCO	2.66%	2.66%	2.66%
PSNC Energy	3.03%	2.90%	2.94%
Weighted average of above	2.63%	2.61%	2.61%
Consolidated SCE&G	2.55%	2.56%	2.56%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in Fuel used in electric generation and recovered through the fuel cost component of retail electric rates.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Unit 1. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership. SCE&G’s share of the direct expenses is included in the corresponding operating expenses on its income statement. Unit 2 and Unit 3 have been reclassified from construction work in progress to a regulatory asset as a result of the decision to stop their construction. See additional discussion at Note 2.

As of December 31,		2017		2016		
		Unit 1		Unit 1		Unit 2 and Unit 3
Percent owned		66.7%		66.7%		55.0%
Plant in service	$	1.5 billion	$	1.3 billion		—
Accumulated depreciation	$	637.6 million	$	634.4 million		—
Construction work in progress	$	110.1 million	$	167.7 million	$	4.2 billion

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for the units. These amounts totaled $53.8 million at December 31, 2017 and $76.2 million at December 31, 2016.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2017, and 2016, SCE&G incurred $26.1 million and $23.8 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, SCE&G accrues $17.2 million annually for its portion of the nuclear refueling outages scheduled from the spring of 2014 through the spring of 2020. Refueling outage costs incurred for which SCE&G was responsible totaled $1.8 million in 2016 in preparation for the Spring 2017 outage and $23.2 million in 2017.

Goodwill

The Company considers certain amounts categorized by FERC as acquisition adjustments to be goodwill. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. Accounting guidance adopted by the Company gives it the option to perform a qualitative assessment of impairment ("step zero"). Based on this qualitative assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with a two-step quantitative assessment. If the quantitative assessment becomes necessary, step one requires estimation of the fair value of the reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Should a write-down be required, such a charge would be treated as an operating expense.

For each period presented, assets with a carrying value of $210 million for PSNC Energy (Gas Distribution segment), net of a writedown of $230 million taken in 2002, were classified as goodwill. The Company utilized the step zero qualitative assessment in its evaluations as of January 1, 2018 and as of January 1, 2017 and was not required to use the two-step quantitative assessment.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The asset balance held in trust reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Temporary cash investments having original maturities of three months or less at time of purchase are considered to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements, treasury bills and money market funds.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Unbilled revenues totaled $220.9 million at December 31, 2017 and $178.9 million at December 31, 2016 for the Company. Unbilled revenues totaled $140.3 million at December 31, 2017 and $117.6 million at December 31, 2016 for Consolidated SCE&G. Other receivables consist primarily of amounts due from Santee Cooper related to the jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable.

PSNC Energy, a subsidiary of SCANA, utilizes an asset management and supply service agreement with a counterparty for certain natural gas storage facilities. Such counterparty held, through an agency relationship, 39% and 40% of PSNC Energy's natural gas inventory at December 31, 2017 and December 31, 2016, respectively, with a carrying value of $11.5 million and $9.8 million, respectively. Under the terms of this agreement, PSNC Energy receives storage asset management fees of which 75% are credited to customers. This agreement expires on March 31, 2019.

Income Taxes

SCANA files consolidated federal income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if such impacts are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, such adjustments are charged or credited to deferred income tax expense. Also, see Note 5 for a discussion of the impact of adjustments recorded upon enactment of the Tax Act.

Consolidated SCE&G is included in the consolidated federal income tax returns of SCANA. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities, including Consolidated SCE&G, record costs that have been or are expected to be allowed in the ratemaking process in periods different from the periods in which the costs would be charged to expense, or record revenues in periods different from the periods in which the revenues would be recorded, by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations for refunds to customers are primarily classified on the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Certain deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as Receivables - Customer or Customer deposits and customer prepayments, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Premiums, discounts and debt issuance costs are presented within long-term debt and are amortized as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Statement of Operations Presentation

Revenues and expenses arising from regulated businesses and, in the case of the Company, the retail natural gas marketing business (including those activities of segments described in Note 12) are presented within Operating Income (Loss), and all other activities are presented within Other Income (Expense). Consistent with this presentation, the Company presents the 2015 gain on the sale of CGT within Operating Income and the 2015 gain on the sale of SCI within Other Income (Expense).

Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not billed.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost proceedings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent proceedings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy's PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings (Loss) Per Share

The Company computes basic earnings (loss) per share by dividing net income (loss) by the weighted average number of common shares outstanding for the period. When applicable, the Company computes diluted earnings (loss) per share using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method.

New Accounting Matters

Recently Adopted

In the first quarter of 2017, the Company and Consolidated SCE&G adopted the following accounting guidance issued by the FASB. The adoption of this guidance had no impact on their respective financial statements except as indicated.

- Guidance issued in August 2014 requires an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern. See related disclosure at Note 10.
- Guidance issued in July 2015 requires most inventory to be measured at the lower of cost and net realizable value.
- Guidance issued in October 2016 requires entities to recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs.

In January 2017, the FASB issued accounting guidance to simplify the accounting for goodwill impairment by removing Step 2 of the goodwill impairment test. The guidance is effective for years beginning in 2020, though early adoption after January 1, 2017 is allowed. The Company adopted this guidance on January 1, 2018, and its adoption had no impact on its financial statements.

Pending Adoption

In the first quarter of 2018, the Company and Consolidated SCE&G will adopt the following accounting guidance issued by the FASB.

- Guidance issued in May 2014 for revenue arising from contracts with customers supersedes most prior revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides for a five-step analysis in determining when and how revenue is recognized, and requires revenue recognition to depict the transfer of promised goods or services to customers, based on the transfer of control, in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. In addition, this guidance requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The analysis of contracts with customers to which the guidance might be applicable has been completed and activities of the FASB's Transition Resource Group for Revenue Recognition, particularly as they relate to the treatment of CIAC, ARP and the collectability of revenue of utilities subject to rate regulation have been considered. Specifically, the Company and Consolidated SCE&G have concluded that their use of CIAC is outside the scope of the new revenue recognition guidance. The Company and Consolidated SCE&G have determined that aspects of SCE&G’s WNA and, for the Company, PSNC Energy's CUT allow for revenue adjustments to be recognized prior to amounts being reflected in customer bills. These revenue adjustments, which give rise to regulatory assets or liabilities, represent ARPs that are outside the scope of the new guidance and will be reported as Other operating revenue separately from revenue from contracts with customers on the statement of operations. An evaluation of the enhanced disclosure requirements is being completed, including determining the appropriate disaggregation of revenue.

  The Company and Consolidated SCE&G will adopt this guidance using the modified retrospective method, and comparative periods will not be restated. In connection with this adoption, the Company has determined that its gas marketing subsidiary serves as an agent for gas distribution services in its retail market. Accordingly, certain pass through charges that the Company currently records within Gas-nonregulated revenues, and which are entirely offset within Gas purchased for resale, in the future will be recorded net on the statements of operations. The Company and Consolidated SCE&G do not anticipate that the adoption of this guidance will have any material impacts on their respective financial statements, but its adoption will result in additional disclosures. The adoption of this guidance will not result in a cumulative effect adjustment to beginning retained earnings.

- Guidance issued in January 2016 changes how entities measure certain equity investments and financial liabilities, among other things. Entities will be required to make a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective, with certain exceptions. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018 and do not anticipate that its adoption will have a significant impact on their respective financial statements.

- Guidance issued in August 2016 is intended to reduce diversity in cash flow statement classification related to certain transactions, and entities must apply the guidance retrospectively to all periods presented. The adoption of this guidance will have no impact on the financial statements of the Company and Consolidated SCE&G.

- Guidance issued in November 2016 clarifies how restricted cash should be presented on the statement of cash flows, and entities must apply the guidance retrospectively to all periods presented. The adoption of this guidance will have no impact on the financial statements of the Company and Consolidated SCE&G.

- Guidance issued in March 2017 changes the required presentation of net periodic pension and postretirement benefit costs. Under this guidance, such costs will be separated into service cost components and other components. The service cost components will be presented in the same line item (or items) as other compensation costs arising from services rendered by employees during the period. The other components will be reported in the income statement separately from the service cost component and outside operating income. Only the service cost component will be eligible for capitalization in assets. Entities must apply this guidance on a retrospective basis for the presentation of the service cost component and the other components, and on a prospective basis for the capitalization of only the service cost component. As permitted, service cost and other costs disclosed in related footnotes to previously issued financial statements will be used when estimating retrospective changes for such costs in the income statements for prior periods. Due to regulatory overlay, non-service cost components related to regulated operations that are capitalized in assets under current accounting guidance will be deferred within regulatory assets in the future. As a result, the adoption of this guidance will not have a material impact on the financial statements of the Company and Consolidated SCE&G.

The Company and Consolidated SCE&G will adopt the following accounting guidance issued by the FASB when indicated below.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over 12 months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further,
and without consideration of any regulatory accounting requirements which may apply, depending primarily on the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight-line basis, also depending on the nature of the assets and relative consumption. In January 2018, FASB amended this accounting guidance to provide an optional transition practical expedient that would allow adopters to not evaluate under the new guidance existing or expired land easements that were not previously accounted for as leases under existing guidance. The new guidance is effective for years beginning in 2019, and the Company and Consolidated SCE&G do not anticipate that its adoption will impact their respective financial statements other than increasing amounts reported for assets and liabilities on the balance sheet and changing the place on their respective statements of operations on which certain expenses are recorded. No impact on net income (loss) is expected. The identification and analysis of leasing and related contracts to which the guidance might be applicable has begun. In addition, the Company and Consolidated SCE&G have begun implementation of a third party software tool that will assist with initial adoption and ongoing compliance. Specifically, preliminary system configuration has been completed and data from certain leases are being entered.

In June 2016, the FASB issued accounting guidance requiring the use of a current expected credit loss impairment model for certain financial instruments. The new model is applicable to trade receivables and most debt instruments, among other financial instruments, and in certain instances may result in impairment losses being recognized earlier than under current guidance. The Company and Consolidated SCE&G must adopt this guidance beginning in 2020, including interim periods, though the guidance may be adopted in 2019. The Company and Consolidated SCE&G have not determined when this guidance will be adopted or what impact it will have on their respective financial statements.

In August 2017, the FASB issued accounting guidance to simplify the application of hedge accounting. Among other things, the new guidance will enable more hedging strategies to qualify for hedge accounting, will allow entities more time to perform an initial assessment of hedge effectiveness, and will permit an entity to perform a qualitative assessment of effectiveness for certain hedges instead of a quantitative one. For cash flow hedges that are highly effective, all changes in the fair value of the derivative hedging instrument will be recorded in other comprehensive income and will be reclassified to earnings in the same period that the hedged item impacts earnings. Fair value hedges will continue to be recorded in current earnings, and any ineffectiveness will impact the income statement. In addition, changes in the fair value of a derivative will be recorded in the same income statement line as the earnings effect of the hedged item, and additional disclosures will be required related to the effect of hedging on individual income statement line items. The guidance must be applied to all outstanding instruments using a modified retrospective method, with any cumulative effect adjustment recorded to opening retained earnings as of the beginning of the first period in which the guidance becomes effective. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2019, though early adoption is permitted, and have not determined what impact such adoption will have on their respective financial statements.

In February 2018, the FASB issued accounting guidance allowing entities to reclassify from AOCI to retained earnings any amounts for stranded tax effects resulting from the Tax Act. The guidance must be applied either in the period of adoption or retrospectively to each period in which the effect of the change was recognized. The Company and Consolidated SCE&G must adopt this guidance beginning in 2019, including interim periods, though the guidance may be adopted earlier. The Company and Consolidated SCE&G have not determined when this guidance will be adopted or what impact it will have on their respective statements of financial position. No impact is expected on statements of operations or cash flows.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved SCE&G's participation in a DER program and recovery of related costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G is to implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. This nameplate capacity goal was achieved in 2017.

By order dated April 29, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties to decrease the total fuel cost component of retail electric rates. SCE&G reduced the total fuel cost component of retail electric rates to reflect lower projected fuel costs and to eliminate over-collected balances of approximately $61 million for base fuel and environmental costs over a 12-month period beginning with the first billing cycle of May 2016. SCE&G also began to recover projected DER program costs of approximately $6.9 million beginning with the first billing cycle of May 2016.

By order dated April 27, 2017, the SCPSC approved a settlement agreement among SCE&G, the ORS and the SCEUC, to increase the total fuel cost component of retail electric rates. SCE&G agreed to set its base fuel component to produce a projected under recovery of $61.0 million over a 12-month period beginning with the first billing cycle of May 2017. SCE&G also agreed to recover, over a 12-month period beginning with the first billing cycle of May 2017, projected DER program costs of approximately $16.5 million. Additionally, deferral of carrying costs will be allowed for base fuel component under-collected balances as they occur.

In October 2017, the SCPSC initiated its 2018 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 10, 2018.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G has removed from rate base certain deferred income tax assets arising from capital expenditures related to Unit 2 and Unit 3 and accrued carrying costs on those amounts during periods in which they were not included in rate base. Such carrying costs were determined at SCE&G’s weighted average long-term debt borrowing rate and were recorded as a regulatory asset and other income. Carrying costs totaled $18.8 million and $14.0 million during 2017 and 2016, respectively. As part of the impairment loss described in Note 10, accumulated carrying costs related to the Nuclear Project totaling $51.0 million were written off.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2017	First billing cycle of May	$37.0 million
2016	First billing cycle of May	$37.6 million
2015	First billing cycle of May	$32.0 million

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider was designed to allow SCE&G to recover projected pension costs, including under-collections, over a 12-month period, beginning with the first billing cycle in May 2016.

By order dated March 1, 2017, the SCPSC approved SCE&G's request to decrease its pension costs rider. The change in the pension rider decreased annual revenue by approximately $11.9 million. The pension rider is designed to allow SCE&G to recover projected pension costs, net of the previously over-collected balance, over a 12-month period, beginning with the first billing cycle in May 2017.

In December 2017, the ORS filed a petition with the SCPSC requesting all investor-owned utilities under the SCPSC's jurisdiction to report the impact of the Tax Act on their individual company's operations. The Tax Act contains provisions that lower the federal corporate tax rate from 35% to 21% effective January 1, 2018. The petition requested that utilities file an estimate of the Tax Act's effects on their most recent test year information available, including an explanation of those effects, and requested that utilities propose procedures for changing rates to reflect the impacts. Lastly, the petition requested that the SCPSC state in its order that rates in effect as of January 1, 2018, be subject to refund so that ratepayers receive the benefit of the tax law changes as of January 1, 2018. By order dated January 10, 2018, the SCPSC granted the ORS petition but did not state that rates in effect as of January 1, 2018 would be subject to refund. SCE&G provided its comments on January 24, 2018, concerning the timing and the format of the report.

In January 2018, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved the filing would allow recovery of $37.0 million of costs and net lost revenues associated with DSM programs, along with an incentive to invest in such programs.

Electric - BLRA and Joint Petition

Under the BLRA, SCE&G filed revised rates with the SCPSC in 2015 and 2016 to incorporate the financing cost of incremental construction work in progress incurred for the Nuclear Project. Rate adjustments were based on SCE&G's updated cost of debt and capital structure and on an allowed ROE. No revised rates filing was pursued in 2017. The SCPSC approved recovery of the following amounts.

Increase	Effective for bills rendered on and after	Amount	Allowed ROE
2.7%	November 27, 2016	$64.4 million	10.50% *
2.6%	October 30, 2015	$64.5 million	11.00%

*Applied prospectively for purposes of calculating revised rates under the BLRA on and after January 1, 2016.

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for Unit 2 and Unit 3 which had been developed in connection with the October 2015 Amendment (see Note 10). On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, the ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. By order dated February 28, 2017, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement, and that denial was not appealed.

The construction schedule approved by the SCPSC in November 2016 provided for contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively. The approved capital cost schedule included incremental capital costs that totaled $831 million, raising SCE&G's total project capital cost as then approved to an estimated amount of approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for the Nuclear Project from 10.5% to 10.25%. This revised ROE was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G could not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request was denied because SCE&G was out of compliance with its approved capital cost schedule or BLRA construction milestone schedule, subject to certain extensions. See also Abandoned Nuclear Project in Note 10.

Following WEC and WECTEC's bankruptcy filing on March 29, 2017, on June 22, 2017, the Friends of the Earth and the Sierra Club filed a complaint against SCE&G with the SCPSC, requesting that the SCPSC initiate a formal proceeding to direct SCE&G to immediately cease and desist from expending any further capital costs related to the construction of Unit 2 and Unit 3; to determine the prudence of acts and omissions by SCE&G in connection with this construction; to review and determine the prudence of abandonment of Unit 2 and Unit 3 and of the available least cost efficiency and renewable energy alternatives; and to remedy, abate and make due reparations for the rates charged to ratepayers related to the construction of Unit 2 and Unit 3. SCE&G filed its answer to the complaint and a motion to dismiss the complaint on July 19, 2017. On October 4, 2017, the SCPSC ordered proceedings under this complaint to be coordinated with proceedings for the Request filed by the ORS on September 26, 2017, described below, and allowed discovery to proceed. SCE&G's subsequent petition for rehearing and reconsideration was denied by the SCPSC on November 1, 2017. Proceedings related to this complaint have been consolidated with proceedings for the Request and the Joint Petition as described below.

On August 1, 2017, SCE&G filed the Abandonment Petition with the SCPSC which sought recovery of costs expended on the construction of Unit 2 and Unit 3, including certain costs incurred subsequent to SCE&G's last revised rates update, other costs under the abandonment provisions of the BLRA, and affirmation of SCE&G's decision to abandon construction of Unit 2 and Unit 3, among other things. Subsequently, SCE&G management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew the Abandonment Petition on August 15, 2017. See additional discussion at Note 10.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which had been previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed with the SCPSC a motion to amend its request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. A hearing on the parties' motions was held on December 12, 2017, and included the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, a large industrial customer, and several environmental groups.

By order dated December 20, 2017, the SCPSC denied SCE&G's Motion to Dismiss the Request and ordered that a hearing be set on the Request. In addition, the SCPSC ordered the ORS to perform a thorough inspection and audit, within 30 days, to determine the reasonableness of SCE&G's retail electric rates and to determine the reasonableness of SCE&G's statements regarding the potential effect that the removal of approximately $445 million in annual revenues, as requested by the ORS, could have on SCE&G. The SCPSC also granted the ORS's motion to amend the Request and consider the monetization of the Toshiba payout along with any other related factors that may be appropriate in determining a fair and reasonable rate. SCE&G intends to vigorously contest the Request, but cannot give any assurance as to the timing or outcome of this matter. Proceedings for the Request, the complaint filed by Friends of the Earth and the Sierra Club on June 22, 2017, and the Joint Petition discussed below have been consolidated.

On November 20, 2017, the ORS filed a letter with the SCPSC providing the ORS's preliminary list for stabilization and protection of the site where Unit 2 and Unit 3 are located and suggesting that the SCPSC have SCE&G respond to the ORS's November 20, 2017 letter and "explain why there is no violation of S.C. Code Ann. § 58-27-1300." The SCPSC granted the ORS's request, and SCE&G filed its response with the SCPSC on December 27, 2017.

On January 12, 2018, SCE&G and Dominion Energy filed with the SCPSC the Joint Petition for review and approval of a proposed business combination whereby SCANA would become a wholly-owned subsidiary of Dominion Energy. In the Joint Petition, approval of a customer benefits plan and a cost recovery plan for the Nuclear Project is also sought. Key provisions of this Joint Petition are summarized at Note 10. A hearing on this matter has not yet been scheduled.

On January 19, 2018, the ORS filed a report with the SCPSC in response to the SCPSC's order for a thorough inspection and audit of SCE&G's statements regarding potential adverse effects that could result from the removal of annual BLRA revenues. The ORS report relied on the analysis of bankruptcy counsel to conclude that the suspension of revised rates collections is unlikely to force SCE&G into bankruptcy. Notwithstanding this conclusion, the ORS predicted that there is 35% likelihood of an SCE&G bankruptcy if revised rates are terminated. The report also indicated that a full audit, as ordered by the SCPSC, would require upwards of 90 days to complete. SCE&G filed responses to the ORS report alleging numerous deficiencies in it, including that the report was not verified by an accountant and that it contained incorrect and misleading accounting conclusions, particularly with regard to the timing and magnitude of any impairment loss that would be required by GAAP. On January 31, 2018, the SCPSC ordered the ORS to complete this previously ordered thorough audit, inspection and examination of SCE&G's accounting records by March 30, 2018, encouraged them to employ the assistance of a utility financial professional if needed, and indicated that a request by the ORS for an extension of time would not be considered unreasonable.

Gas - SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action		Amount
2017	2.2%	Increase	$8.6 million
2016	1.2%	Increase	$4.1 million
2015	No change		—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2017, 2016 and 2015 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent. See Electric - Base Rates for a discussion of the ORS petition related to the Tax Act, which also applies to Gas - SCE&G.

Gas - PSNC Energy

PSNC Energy's Rider D rate mechanism allows it to recover from customers all prudently incurred gas costs and certain related uncollectible expenses as well as losses on negotiated gas and transportation sales.

PSNC Energy establishes rates using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy’s gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

On October 28, 2016, the NCUC granted PSNC Energy a net annual increase of approximately $19.1 million, or 4.39%, in rates and charges to customers, and set PSNC Energy's authorized ROE at 9.7%. In addition, the NCUC has authorized PSNC Energy to use a tracker mechanism to recover the incurred capital investment and associated costs of complying with federal standards for pipeline integrity and safety requirements that are not in current base rates. PSNC Energy has filed biannual applications to adjust its rates for this purpose, and the NCUC has approved those applications for the incremental annual revenue requirements, as follows:

Rates Effective	Incremental Increase
March 1, 2017	$1.9 million
September 1, 2017	$0.7 million

In December 2017, in connection with PSNC Energy's 2017 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2017.

On January 3, 2018, the NCUC sought reports from its jurisdictional utilities as to how they planned to respond to the Tax Act. In its response on February 1, 2018, PSNC Energy proposed certain adjustments to its rates that, if enacted, would serve to reduce amounts that are currently being collected from customers based on pre-Tax Act rates. PSNC Energy cannot determine when the NCUC may take action on this matter.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, the Company and Consolidated SCE&G have recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Except for certain unrecovered Nuclear Project costs and other unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	The Company		Consolidated SCE&G	
	December 31,		December 31,	
Millions of dollars	2017	2016	2017	2016
Regulatory Assets:				
Unrecovered Nuclear Project costs	$ 3,976	—	$ 3,976	—
Accumulated deferred income taxes	—	$ 316	—	$ 307
AROs and related funding	434	425	410	403
Deferred employee benefit plan costs	305	342	273	309
Deferred losses on interest rate derivatives	456	620	456	620
Other unrecovered plant	105	117	105	117
DSM Programs	59	59	59	59
Carrying costs on deferred tax assets related to the Nuclear Project	—	32	—	32
Pipeline integrity management costs	51	33	8	6
Environmental remediation costs	30	32	25	26
Deferred storm damage costs	24	20	24	20
Deferred costs related to uncertain tax position	—	15	—	15
Other	140	119	140	116
Total Regulatory Assets	$ 5,580	$ 2,130	$ 5,476	$ 2,030
Regulatory Liabilities:				
Monetization of guaranty settlement	$ 1,095	—	$ 1,095	—
Accumulated deferred income taxes	1,076	23	914	14
Asset removal costs	757	755	527	529
Deferred gains on interest rate derivatives	131	151	131	151
Other	—	1	—	1
Total Regulatory Liabilities	$ 3,059	$ 930	$ 2,667	$ 695

Regulatory assets for unrecovered Nuclear Project costs have been recorded based on such amounts not being probable of loss in accordance with the accounting guidance on abandonments, whereas the other regulatory assets have been recorded based on the probability of their recovery. All regulatory assets represent incurred costs that may be deferred under applicable GAAP for regulated operations. The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders certain of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by one of these regulatory agencies, including unrecovered nuclear project costs that are the subject of regulatory proceedings as further discussed in Note 10. In recording such costs as regulatory assets, management believes the costs would be allowable under existing rate-making concepts that are embodied in rate orders or current state law. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation, changes in state law, other changes in the regulatory environment or changes in accounting requirements, the Company or Consolidated SCE&G could be required to write off all or a portion of its regulatory assets and liabilities. Such an event could have a material effect on the Company's and Consolidated SCE&G's financial statements in the period the write-off would be recorded.

Unrecovered Nuclear Project costs represents expenditures by SCE&G that have been reclassified from construction work in progress as a result of the decision to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs under the abandonment provisions of the BLRA or through other regulatory means, net of an estimated impairment loss and the transfer of certain assets described at Note 10.

Accumulated deferred income taxes contained within regulatory assets represent deferred tax liabilities that arise from utility operations that have not been included in customer rates. A portion of these regulatory assets related to depreciation and are netted within regulatory liabilities in the current period.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Unit 1 and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 107 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. SCE&G recovers deferred pension costs through utility rates of approximately $2 million annually for electric operations, which will end in 2044, and approximately $1 million annually for gas operations, which will end in 2027. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees up to approximately 11 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when such amounts are applied otherwise at the direction of the SCPSC. See also Note 10 for a discussion of certain amounts that were treated as impaired as of December 31, 2017.

Other unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent SCE&G's deferred costs associated with electric demand reduction programs, and such deferred costs are currently being recovered over approximately five years through an approved rate rider.

Carrying costs on deferred tax assets related to the Nuclear Project were calculated on accumulated deferred income tax assets associated with Unit 2 and Unit 3 which were not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs were written off as a part of the impairment loss in 2017. See also Note 10.

Pipeline integrity management costs represent operating and maintenance costs incurred to comply with federal regulatory requirements related to natural gas pipelines. PSNC Energy is recovering costs totaling $4.1 million annually through 2021. PSNC Energy is continuing to defer pipeline integrity costs, and as of December 31, 2017 costs of $26.6 million have been deferred pending future approval of rate recovery. SCE&G amortizes $1.9 million of such costs annually.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G or PSNC Energy. SCE&G's remediation costs are expected to be recovered over periods of up to approximately 17 years, and PSNC Energy's remediation costs total $6.9 million are being recovered over a five year period that will end in 2021.

Deferred storm damage costs represent costs incurred in excess of amounts previously collected through SCE&G's SCPSC-approved storm damage reserve, and for which SCE&G expects to receive future recovery through customer rates.

Deferred costs related to uncertain tax position primarily represented the estimated amounts of domestic production activities deductions foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest expense and other costs arising from this uncertain tax position. SCE&G's current customer rates reflect the availability of domestic production activities deductions. These net deferred costs were written off as a part of the impairment loss in 2017. See Note 5 and Note 10.

Various other regulatory assets are expected to be recovered through rates over periods through 2047.

Monetization of guaranty settlement represents proceeds received under or arising from the monetization of the Toshiba Settlement, net of certain expenses.

Accumulated deferred income taxes contained within regulatory liabilities represent (i) excess deferred income taxes arising from the remeasurement of deferred income taxes upon the enactment of the Tax Act (certain of which are protected under normalization regulations and will be amortized over the remaining lives of related property, and certain of which will be amortized to the benefit of customers over a prescribed period as instructed by regulators) and (ii) deferred income taxes arising from investment tax credits, offset by (iii) deferred income taxes that arise from utility operations that have not been included in customer rates (a portion of which relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years). See also Note 5.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

3. COMMON EQUITY

Authorized shares of SCANA common stock were 200 million as of December 31, 2017 and 2016. Authorized shares of SCE&G common stock were 50 million as of December 31, 2017 and 2016. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2017 and 2016.

SCANA's articles of incorporation do not limit the dividends that may be paid on its common stock, and the articles of incorporation of each of SCANA's subsidiaries contain no such limitations on their respective common stock. SCANA has agreed to obtain the consent of Dominion Energy, which consent cannot be unreasonably withheld, prior to making dividend payments to shareholders greater than $0.6125 per share for any quarter while the Merger Agreement is pending.

SCE&G's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. SCE&G's bond indenture permits the payment of dividends on SCE&G's common stock only either (1) out of its Surplus (which as defined in the bond indenture equates to its retained earnings) or (2) in case there is no Surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, the Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2017 and 2016, retained earnings of approximately $93.9 million and $79.0 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

PSNC Energy's note purchase and debenture purchase agreements contain provisions that could limit the payment of cash distributions, including dividends, on PSNC Energy's common stock. These agreements generally limit the sum of distributions to an amount that does not exceed $30 million *plus* 85% of Consolidated Net Income (as therein defined) accumulated after December 31, 2008 *plus* the net proceeds of issuances by PSNC Energy of equity or convertible debt securities (as therein defined). As of December 31, 2017, this limitation would permit PSNC Energy to pay cash distributions in excess of $100 million.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

The Company

December 31, Dollars in millions	Maturity	2017 Balance	2017 Rate	2016 Balance	2016 Rate
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%
SCANA Senior Notes (unsecured) (a)	2018 - 2034	75	2.18%	79	1.63%
SCE&G First Mortgage Bonds (secured)	2018 - 2065	4,840	5.80%	4,840	5.79%
GENCO Notes (secured)	2018 - 2024	207	5.94%	213	5.93%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.52%	122	3.51%
PSNC Energy Senior Debentures and Notes	2020 - 2046	600	5.19%	450	5.53%
Other	2018 - 2027	28	2.83%	27	2.76%
Total debt		6,672		6,531	
Current maturities of long-term debt		(727)		(17)	
Unamortized discount, net		(1)		(1)	
Unamortized debt issuance costs		(38)		(40)	
Total long-term debt, net		$ 5,906		$ 6,473	

Consolidated SCE&G

December 31, Dollars in millions	Maturity	2017 Balance	2017 Rate	2016 Balance	2016 Rate
First Mortgage Bonds (secured)	2018 - 2065	$ 4,840	5.80%	$ 4,840	5.79%
GENCO Notes (secured)	2018 - 2024	207	5.94%	213	5.93%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.52%	122	3.51%
Other	2018 - 2027	28	2.83%	26	2.76%
Total debt		5,197		5,201	
Current maturities of long-term debt		(723)		(12)	
Unamortized premium, net		1		1	
Unamortized debt issuance costs		(34)		(36)	
Total long-term debt, net		$ 4,441		$ 5,154	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%).
(b) Includes variable rate debt of $67.8 million at December 31, 2017 (rate of 1.85%) and 2016 (rate of 0.76%) which are hedged by fixed swaps.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. Also in June 2016, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2017, PSNC Energy issued $150 million of 4.18% senior notes due June 30, 2047. In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from these sales were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

The Company's long-term debt maturities will be $727 million in 2018, $16 million in 2019, $366 million in 2020, $494 million in 2021 and $264 million in 2022. These amounts include, for Consolidated SCE&G, $723 million in 2018, $12 million in 2019, $11 million in 2020, $40 million in 2021 and $9 million in 2022.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be issued (Bond Ratio). For the year ended December 31, 2017, the Bond Ratio was 5.24. Adjusted Net Earnings, as therein defined, excludes the impairment loss.

Lines of Credit and Short-Term Borrowings

At December 31, 2017 and 2016, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	Total	SCANA	SCE&G	PSNC Energy
December 31, 2017				
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 350.3	—	$ 251.6	$ 98.7
Weighted average interest rate		—	1.92%	1.93%
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,646.4	$ 397.0	$ 1,148.1	$ 101.3
December 31, 2016				
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 940.5	$ 64.4	$ 804.3	$ 71.8
Weighted average interest rate		1.43%	1.04%	1.07%
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,056.2	$ 332.6	$ 595.4	$ 128.2

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to credit agreements in the amounts and for the terms described above. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018. Were adverse developments to occur with respect to uncertainties highlighted elsewhere, the ability of SCE&G or GENCO to secure renewal of this short-term borrowing authority may be adversely impacted.

Each of the Company and Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2017, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $37 million and investments due from an affiliate of $28 million. At December 31, 2016, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $29 million. On SCE&G's consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense (benefit) are as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Current taxes (benefit):						
Federal	$ (414)	$ 36	$ 382	$ (410)	$ 50	$ 208
State	18	13	57	(18)	13	32
Total current taxes (benefit)	(396)	49	439	(428)	63	240
Deferred tax (benefit) expense, net:						
Federal	323	203	(36)	261	167	(3)
State	(37)	21	(7)	(2)	20	(3)
Total deferred taxes (benefit)	286	224	(43)	259	187	(6)
Investment tax credits:						
Amortization of amounts deferred-state	—	—	(1)	—	—	(1)
Amortization of amounts deferred-federal	(2)	(2)	(2)	(2)	(2)	(2)
Total investment tax credits	(2)	(2)	(3)	(2)	(2)	(3)
Total income tax expense (benefit)	$ (112)	$ 271	$ 393	$ (171)	$ 248	$ 231

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Net income (loss)	$ (119)	$ 595	$ 746	$ (185)	$ 513	$ 466
Income tax expense (benefit)	(112)	271	393	(171)	248	231
Noncontrolling interest	—	—	—	13	13	14
Total pre-tax income (loss)	$ (231)	$ 866	$ 1,139	$ (343)	$ 774	$ 711
Income taxes (benefit) on above at statutory federal income tax rate	$ (81)	$ 303	$ 399	$ (120)	$ 271	$ 249
Increases (decreases) attributed to:						
State income taxes (less federal income tax effect)	(7)	27	38	(8)	26	24
State investment tax credits (less federal income tax effect)	(5)	(5)	(6)	(5)	(5)	(6)
Allowance for equity funds used during construction	(8)	(10)	(9)	(5)	(9)	(9)
Deductible dividends—401(k) Retirement Savings Plan	(9)	(10)	(10)	—	—	—
Amortization of federal investment tax credits	(2)	(2)	(2)	(2)	(2)	(2)
Section 45 tax credits	(8)	(8)	(9)	(8)	(8)	(9)
Domestic production activities deduction	(18)	(23)	(18)	(18)	(23)	(18)
Remeasurement of deferred taxes upon enactment of Tax Act	30	—	—	(1)	—	—
Realization of basis differences upon sale of subsidiaries	—	—	7	—	—	—
Other differences, net	(4)	(1)	3	(4)	(2)	2
Total income tax expense (benefit)	$ (112)	$ 271	$ 393	$ (171)	$ 248	$ 231

The tax effects of significant temporary differences comprising net deferred tax liabilities are as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	**2017**	**2016**	**2017**	**2016**
Deferred tax assets:				
Net operating loss and tax credit carryforward	$ 600	—	$ 541	—
Toshiba settlement	273	—	273	—
Nondeductible accruals	88	$ 148	42	$ 53
Asset retirement obligation, including nuclear decommissioning	141	213	132	200
Regulatory liability, non-property accumulated deferred income tax	54	—	54	—
Financial instruments	15	22	—	—
Unamortized investment tax credits	8	15	8	15
Deferred fuel costs	—	17	—	17
Other	6	10	5	8
Total deferred tax assets	1,185	425	1,055	293
Deferred tax liabilities:				
Property, plant and equipment	1,220	2,159	1,035	1,856
Regulatory asset, unrecovered nuclear plant costs	962	—	962	—
Deferred employee benefit plan costs	60	105	53	93
Regulatory asset, asset retirement obligation	91	143	85	135
Regulatory asset, other unrecovered plant	27	45	27	45
Demand side management costs	16	23	16	23
Prepayments	21	32	19	30
Other	49	77	31	50
Total deferred tax liabilities	2,446	2,584	2,228	2,232
Net deferred tax liabilities	$ 1,261	$ 2,159	$ 1,173	$ 1,939

The federal and state tax credits and NOL carryforwards are presented below:

	December 31, 2017		
Millions of dollars	**The Company**	**Consolidated SCE&G**	**Expiration Year**
Federal NOL Carryforwards	$ 2,052	$ 1,905	2037
Federal Tax Credits	35	35	2035 - 2037
Federal Charitable Carryforwards	7	5	2021 - 2022
State NOL Carryforwards	2,382	2,301	2037
State Charitable Carryforwards	3	2	2022
Total Tax Credits and NOL Carryforwards	$ 4,479	$ 4,248	

A valuation allowance is needed when it is more likely than not that all or a portion of a deferred tax asset will not be realized. In determining whether a valuation allowance is required, the Company and Consolidated SCE&G consider such factors as prior earnings history, expected future earnings, carryback and carryforward periods, and tax strategies that could potentially enhance the likelihood of the realization of a deferred tax asset. Based on this evaluation, management has concluded that a valuation allowance is not needed.

In December 2017, the Tax Act was enacted, resulting in the remeasurement of all federal deferred income tax assets and liabilities to reflect a 21% federal statutory tax rate. Due to the regulated nature of the Company's and Consolidated SCE&G's operations, the effect of this remeasurement is primarily reflected in deferred income tax balances within regulatory liabilities (see Note 2). In connection with this remeasurement, however, the Company recorded additional deferred income tax expense of approximately $30 million, and Consolidated SCE&G recorded a deferred income tax benefit of approximately $1 million in their respective statements of operations for the year ended December 31, 2017. Upon the eventual filing of the Company's 2017 consolidated income tax return, adjustments to deferred income taxes and deferred income taxes may be recorded; however, these adjustments are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

The State of North Carolina lowered its corporate income tax rate from 6.0% to 5.0% in 2015, 4.0% in 2016, 3% in 2017 and 2.5% effective January 1, 2019. In connection with these changes in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The changes in income tax rates did not and are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

The Company files consolidated federal income tax returns which includes Consolidated SCE&G, and the Company and its subsidiaries file various applicable state and local income tax returns.

The IRS has completed examinations of the Company's federal returns through 2004, and the Company's federal returns through 2009 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2015 as a result of claims discussed below. With few exceptions, the Company, including Consolidated SCE&G, is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes in Unrecognized Tax Benefits

	The Company			Consolidated SCE&G		
Millions of dollars	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Unrecognized tax benefits, January 1	$ 350	$ 49	$ 16	$ 350	$ 49	$ 16
Gross increases—uncertain tax positions in prior period	—	94	33	—	94	33
Gross decreases—uncertain tax positions in prior period	(273)	—	(2)	(273)	—	(2)
Gross increases—current period uncertain tax positions	21	207	2	21	207	2
Unrecognized tax benefits, December 31	$ 98	$ 350	$ 49	$ 98	$ 350	$ 49

During 2013 and 2014, the Company amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). The Company also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In 2016 and 2017, the Company claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the design and construction activities of the Nuclear Project, in its 2015 and 2016 income tax returns. The Company expects to claim similar deductions and credits in its 2017 tax return when it is filed in 2018. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models.

The IRS examined the claims in the amended returns, and as the examination progressed without resolution, the Company and Consolidated SCE&G evaluated and recorded adjustments to unrecognized tax benefits; however, none of these changes materially affected the Company's and Consolidated SCE&G's effective tax rate. In October 2016, the examination of the amended tax returns progressed to the IRS Office of Appeals. In addition, the IRS has begun an examination of SCANA's 2013 through 2015 income tax returns, and it is expected that the IRS will also examine later returns.

These IRC Section 174 income tax deductions and IRC Section 41 credits were considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities were recorded as unrecognized tax benefits in the financial statements. Following the abandonment of the Nuclear Project, the Company and Consolidated SCE&G anticipate that an abandonment loss deduction under IRC Section 165 will be claimed on the 2017 tax return. As such, certain of the IRC Section 174 deductions, to the extent they are denied, would instead be deductible in 2017 under IRC Section 165. The abandonment loss deduction is also considered an uncertain tax position; however, under relevant accounting guidance, no estimated unrecognized tax benefits were recorded as of December 31, 2017. The remaining unrecognized tax benefits include the impact of the IRC Section 174 deductions on domestic production activities deductions, credits, and certain unrecognized state tax benefits.

As of December 31, 2017, the Company and Consolidated SCE&G have recorded an unrecognized tax benefit of $98 million ($19 million net of the impact of state deductions on federal returns, net of NOL and credit carryforwards, and net of receivables related to the uncertain tax positions). If recognized, $98 million of the tax benefit would affect the Company's and Consolidated SCE&G's effective tax rates. These unrecognized tax benefits are not expected to increase significantly within the next 12 months. It is also reasonably possible that these unrecognized tax benefits may decrease by $11 million within the next 12 months. No other material changes in the status of the Company's or Consolidated SCE&G's tax positions have occurred through December 31, 2017.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 and 2016 income tax returns and similar claims made in determining taxable income for 2017, and under the terms of an SCPSC order, the Company and Consolidated SCE&G recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, with the expectation that these deferred costs and related interest thereon would be recoverable through customer rates in future years (see Note 2). However, as further described in Note 10, as of December 31, 2017, an impairment loss with respect to such deferred regulatory asset was recorded. SCE&G's current customer rates reflect the availability of domestic production activities deductions.

Also under the terms of an SCPSC order, estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 and 2016 income tax returns was deferred as a regulatory asset and was expected to be recoverable through customer rates in future years. An impairment loss with respect to these deferred amounts was also recorded as of December 31, 2017 (see Note 10). Otherwise, the Company and Consolidated SCE&G recognize interest accrued related to unrecognized tax benefits within interest expense or interest income and recognize tax penalties within other expenses. Amounts recorded for such interest income, interest expense or tax penalties have not been material for any period presented.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Derivative instruments are recognized either as assets or liabilities in the statement of financial position and are measured at fair value. Changes in the fair value of derivative instruments are recognized either in earnings, as a component of other comprehensive income (loss) or, for regulated operations, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures, and in some cases risk limits, are established to control the level of market, credit, liquidity and operational and administrative risks. SCANA’s Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Risk Management Officer and other senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statements of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and NYMEX futures and options. PSNC Energy’s tariffs include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the under- or over-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SCANA Energy, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

Interest rate swaps may be used to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which swaps designated as cash flow hedges are used to synthetically convert variable rate debt to fixed rate debt, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

Forward starting swap agreements that are designated as cash flow hedges may be used in anticipation of the issuance of debt. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For SCANA and its nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated for accounting purposes as cash flow hedges and fair value changes and settlement amounts related to them have been recorded as regulatory assets and liabilities. Settlement losses on swaps have generally been amortized over the lives of subsequent debt issuances and gains have been amortized to interest expense or may be applied as otherwise directed by the SCPSC. However, see Note 10 for a discussion of the impairment of previously deferred regulatory asset amounts related to settlement losses on swaps that had been entered into for debt that was anticipated to be issued in connection with the Nuclear Project.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)		
Hedge designation	**Gas Distribution**	**Gas Marketing**	**Total**
As of December 31, 2017			
Commodity	6,430,000	13,433,000	19,863,000
Energy Management (a)	—	41,856,890	41,856,890
Total (a)	6,430,000	55,289,890	61,719,890
As of December 31, 2016			
Commodity	4,510,000	11,947,000	16,457,000
Energy Management (a)	—	67,447,223	67,447,223
Total (a)	4,510,000	79,394,223	83,904,223

(a) Includes amounts related to basis swap contracts totaling 2,582,000 MMBTU in 2017 and 730,721 MMBTU in 2016.

The aggregate notional amounts of the interest rate swaps were as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	**December 31, 2017**	**December 31, 2016**	**December 31, 2017**	**December 31, 2016**
Designated as hedging instruments	$ 111.2	$ 115.6	$ 36.4	$ 36.4
Not designated as hedging instruments	735.0	1,285.0	735.0	1,285.0

The following table shows the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the consolidated balance sheet, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Fair Values of Derivative Instruments

Millions of dollars	Balance Sheet Location	The Company Asset	The Company Liability	Consolidated SCE&G Asset	Consolidated SCE&G Liability
As of December 31, 2017					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 3		$ 1
	Other deferred credits and other liabilities		24		9
Commodity contracts					
	Prepayments		2		
	Other current liabilities		1		
Total		—	$ 30	—	$ 10
Not designated as hedging instruments					
Interest rate contracts					
	Other deferred debits and other assets				
	Derivative financial instruments	$ 54	$ 1	$ 54	$ 1
	Other deferred credits and other liabilities		4		4
Commodity contracts					
	Other current assets	1			
Energy management contracts					
	Prepayments		1		
	Other current assets	3			
	Other deferred debits and other assets	1			
	Derivative financial instruments		2		
Total		$ 59	$ 8	$ 54	$ 5
As of December 31, 2016					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 4		$ 1
	Other deferred credits and other liabilities		24		8
Commodity contracts					
	Prepayments	$ 5			
	Other current assets	1			
Total		$ 6	$ 28	—	$ 9
Not designated as hedging instruments					
Interest rate contracts					
	Other deferred debits and other assets	$ 71		$ 71	
	Derivative financial instruments		$ 27		$ 27
	Other deferred credits and other liabilities		3		3
Commodity contracts					
	Other current assets	3			
Energy management contracts					
	Prepayments	6	2		
	Other current assets	2	1		
	Other deferred debits and other assets	2			
	Derivative financial instruments		4		
	Other deferred credits and other liabilities		2		
Total		$ 84	$ 39	$ 71	$ 30

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

The Company and Consolidated SCE&G:	**Loss Deferred in Regulatory Accounts**		**Loss Reclassified from Deferred Accounts into Income (Effective Portion)**		
Millions of dollars	**(Effective Portion)**		**Location**	**Amount**	
Year Ended December 31, 2017					
Interest rate contracts	$	(2)	Interest expense	$	(2)
Year Ended December 31, 2016					
Interest rate contracts		—	Interest expense	$	(2)
Year Ended December 31, 2015					
Interest rate contracts	$	(3)	Interest expense	$	(3)

The Company:	**Gain or (Loss) Recognized in OCI, net of tax**		**Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion)**		
Millions of dollars	**(Effective Portion)**		**Location**	**Amount**	
Year Ended December 31, 2017					
Interest rate contracts		—	Interest expense	$	(7)
Commodity contracts	$	(7)	Gas purchased for resale		1
Total	$	(7)		$	(6)
Year Ended December 31, 2016					
Interest rate contracts	$	(1)	Interest expense	$	(7)
Commodity contracts		5	Gas purchased for resale		(6)
Total	$	4		$	(13)
Year Ended December 31, 2015					
Interest rate contracts	$	(2)	Interest expense	$	(7)
Commodity contracts		(10)	Gas purchased for resale		(15)
Total	$	(12)		$	(22)

As of December 31, 2017, the Company expects that during the next 12 months reclassifications from AOCI to earnings arising from cash flow hedges will include approximately $3.3 million as an increase to gas cost, assuming natural gas markets remain at their current levels, and approximately $7.2 million as an increase to interest expense, assuming financial markets remain at their current levels. As of December 31, 2017, all of the Company's commodity cash flow hedges settle by their terms before the end of the fourth quarter of 2020.

As of December 31, 2017, each of the Company and Consolidated SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.5 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

For the Company and Consolidated SCE&G, ineffectiveness on interest rate hedges designated as cash flow hedges was insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

The Company and Consolidated SCE&G:	**Loss Deferred in**		**Gain (Loss) Reclassified from Deferred Accounts into Income**		
Millions of dollars	**Regulatory Accounts**		**Location**	**Amount**	
Year Ended December 31, 2017					
Interest rate contracts	$	(32)	Interest Expense	$	(3)
Interest rate contracts			Impairment Loss		(173)
Year Ended December 31, 2016					
Interest rate contracts	$	(34)	Other income	$	(2)
Year Ended December 31, 2015					
Interest rate contracts	$	(69)	Other income	$	5

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2. For more discussion of amounts reclassified to Impairment Loss, see Note 10.

As of December 31, 2017, the Company and Consolidated SCE&G expect that during the next 12 months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $2.7 million as an increase to interest expense.

Credit Risk Considerations

Certain derivative contracts contain contingent credit features. These features may include (i) material adverse change clauses or payment acceleration clauses that could result in immediate payments or (ii) the posting of letters of credit or termination of the derivative contract before maturity if specific events occur, such as a credit rating downgrade below investment grade or failure to post collateral.

Derivative Contracts with Credit Contingent Features

	The Company				**Consolidated SCE&G**			
Millions of dollars	**December 31, 2017**		**December 31, 2016**		**December 31, 2017**		**December 31, 2016**	
in Net Liability Position								
Aggregate fair value of derivatives in net liability position	$	33.7	$	50.3	$	14.7	$	30.3
Fair value of collateral already posted		28.9		29.2		10.1		9.2
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered		4.8		21.1		4.6		21.1
in Net Asset Position								
Aggregate fair value of derivatives in net asset position	$	53.5	$	62.9	$	53.5	$	62.0
Fair value of collateral already posted		—		—		—		—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered		53.5		62.9		53.5		62.0

In addition, for fixed price supply contracts offered to certain of SCANA Energy's customers, the Company could have called on letters of credit in the amount of $1.2 million related to $4.0 million in commodity derivatives that are in a net asset position at December 31, 2017, compared to letters of credit of $1.5 million related to derivatives of $9.0 million at December 31, 2016, if all the contingent features underlying these instruments had been fully triggered.

Information related to the offsetting derivative assets follows:

Derivative Assets	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2017					
Gross Amounts of Recognized Assets	$ 54	$ 1	$ 4	$ 59	$ 54
Gross Amounts Offset in Statement of Financial Position			—	—	
Net Amounts Presented in Statement of Financial Position	54	1	4	59	54
Gross Amounts Not Offset - Financial Instruments	—			—	—
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 54	$ 1	$ 4	$ 59	$ 54
Balance sheet location					
Other current assets				$ 58	$ 54
Other deferred debits and other assets				1	
Total				$ 59	$ 54
As of December 31, 2016					
Gross Amounts of Recognized Assets	$ 71	$ 9	$ 10	$ 90	$ 71
Gross Amounts Offset in Statement of Financial Position			(4)	(4)	
Net Amounts Presented in Statement of Financial Position	71	9	6	86	71
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 62	$ 9	$ 6	$ 77	$ 62
Balance sheet location					
Prepayments				$ 9	
Other current assets				5	
Other deferred debits and other assets				72	$ 71
Total				$ 86	$ 71

Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2017					
Gross Amounts of Recognized Liabilities	$ 32	3	$ 3	$ 38	$ 15
Gross Amounts Offset in Statement of Financial Position			(1)	(1)	
Net Amounts Presented in Statement of Financial Position	32	3	2	37	15
Gross Amounts Not Offset - Financial Instruments	—			—	—
Gross Amounts Not Offset - Cash Collateral Posted	28		(1)	27	—
Net Amount	$ 60	$ 3	$ 1	$ 64	$ 15
Balance sheet location					
Other current assets				$ 2	
Derivative financial instruments				7	$ 2
Other deferred credits and other liabilities				28	13
Total				$ 37	$ 15

As of December 31, 2016					
Gross Amounts of Recognized Liabilities	$ 58		$ 9	$ 67	$ 39
Gross Amounts Offset in Statement of Financial Position			(3)	(3)	
Net Amounts Presented in Statement of Financial Position	58	—	6	64	39
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Posted	(29)			(29)	(9)
Net Amount	$ 20	—	$ 6	$ 26	$ 21
Balance sheet location					
Derivative financial instruments				$ 35	$ 28
Other deferred credits and other liabilities				29	11
Total				$ 64	$ 39

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Available for sale securities are valued using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded or are open-ended mutual funds registered with the SEC which maintain a stable NAV and are invested in government money market agreements or fully collateralized repurchase agreements. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2017				As of December 31, 2016		
	The Company		Consolidated SCE&G		The Company		Consolidated SCE&G
Millions of dollars	**Level 1**	**Level 2**	**Level 1**	**Level 2**	**Level 1**	**Level 2**	**Level 2**
Assets:							
Available for sale securities	$ 119	—	$ 100	—	$ 14	—	—
Held to maturity securities	—	$ 6	—	—	—	$ 7	—
Interest rate contracts	—	54	—	$ 54	—	71	$ 71
Commodity contracts	1	—	—	—	8	1	—
Energy management contracts	—	4	—	—	6	4	—
Liabilities:							
Interest rate contracts	—	32	—	15	—	58	39
Commodity contracts	2	1	—	—	—	—	—
Energy management contracts	1	4	—	—	2	10	—

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2017 and December 31, 2016 were as follows:

	As of December 31, 2017		As of December 31, 2016	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
The Company	$ 6,632.9	$ 7,399.7	$ 6,489.8	$ 7,183.3
Consolidated SCE&G	5,163.3	5,790.3	5,166.0	5,752.3

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

In connection with the impairment loss described in Note 10, the Company and Consolidated SCE&G determined that the fair value of certain of their nuclear fuel was lower than its carrying amount. At December 31, 2017, this nuclear fuel had an estimated fair value of $43.8 million. This estimate is based on quoted prices received from vendors of nuclear fuel, which are considered to be Level 3 fair value measurements. The Company and Consolidated SCE&G assess the fair value of nuclear fuel in connection with the analysis of impairment described in Note 10 on a quarterly basis.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. SCE&G participates in SCANA's pension plan. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. SCE&G participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	The Company				Consolidated SCE&G			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2017	2016	2017	2016	2017	2016	2017	2016
Benefit obligation, January 1	$ 904.3	$ 855.4	$ 274.7	$ 253.6	$ 768.4	$ 724.0	$ 207.2	$ 191.7
Service cost	21.7	20.7	4.5	4.4	18.1	16.9	3.7	3.6
Interest cost	37.4	39.4	11.5	12.1	31.9	33.4	9.5	9.9
Plan participants' contributions	—	—	1.3	1.7	—	—	1.1	1.3
Actuarial (gain) loss	42.2	45.0	9.7	14.0	36.6	41.8	6.8	11.5
Benefits paid	(72.4)	(56.2)	(12.5)	(11.1)	(62.0)	(47.7)	(10.3)	(9.1)
Amounts Funded to parent	n/a	n/a	n/a	n/a	—	—	(1.4)	(1.7)
Benefit obligation, December 31	$ 933.2	$ 904.3	$ 289.2	$ 274.7	$ 793.0	$ 768.4	$ 216.6	$ 207.2

The accumulated benefit obligation for pension benefits for the Company was $905.8 million at the end of 2017 and $874.3 million at the end of 2016. The accumulated benefit obligation for pension benefits for Consolidated SCE&G was $769.7 million at the end of 2017 and $742.9 million at the end of 2016.The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
Annual discount rate used to determine benefit obligation	3.71%	4.22%	3.74%	4.30%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease gradually to 5.0% for 2023 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate for the Company would increase the postretirement benefit obligation by $1.6 million at December 31, 2017 and by $0.8 million at December 31, 2016. A one percent decrease in the assumed health care cost trend rate for the Company would decrease the postretirement benefit obligation by $1.4 million at December 31, 2017 and by $0.7 million at December 31, 2016. A one percent increase in the assumed health care cost trend rate for Consolidated SCE&G would increase the postretirement benefit obligation by $1.3 million at December 31, 2017 and by $0.6 million at December 31, 2016. A one percent decrease in the assumed health care cost trend rate for Consolidated SCE&G would decrease the postretirement benefit obligation by $1.1 million at December 31, 2017 and by $0.6 million at December 31, 2016.

Funded Status

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Fair value of plan assets	$ 849.6	$ 793.6	—	—	$ 781.3	$ 732.9	—	—
Benefit obligation	933.2	904.3	$ 289.2	$ 274.7	793.0	768.4	$ 216.6	$ 207.2
Funded status	$ (83.6)	$ (110.7)	$ (289.2)	$ (274.7)	$ (11.7)	$ (35.5)	$ (216.6)	$ (207.2)

Amounts recognized on the consolidated balance sheets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Current liability	—	—	$ (13.5)	$ (12.6)	—	—	$ (10.8)	$ (10.4)
Noncurrent liability	$ (83.6)	$ (110.7)	(275.7)	(262.1)	$ (11.7)	$ (35.5)	(205.8)	(196.8)

Amounts recognized in accumulated other comprehensive loss were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Net actuarial loss	$ 8.8	$ 10.4	$ 3.5	$ 2.5	$ 2.1	$ 1.9	$ 1.5	$ 1.0
Prior service cost	0.1	0.1	—	—	—	—	—	—
Total	$ 8.9	$ 10.5	$ 3.5	$ 2.5	$ 2.1	$ 1.9	$ 1.5	$ 1.0

Amounts recognized in regulatory assets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**		**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Net actuarial loss	$ 194.8	$ 236.1	$ 43.3	$ 34.7	$ 171.4	$ 208.8	$ 35.9	$ 29.3
Prior service cost	1.2	2.5	—	—	1.0	2.2	—	—
Total	$ 196.0	$ 238.6	$ 43.3	$ 34.7	$ 172.4	$ 211.0	$ 35.9	$ 29.3

In connection with the joint ownership of Summer Station, costs related to the pension benefit obligation attributable to Santee Cooper as of December 31, 2017 and 2016 totaled $21.4 million and $23.4 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2017 and 2016 totaled $14.7 million and $15.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

Pension Benefits	**The Company**		**Consolidated SCE&G**	
Millions of dollars	**2017**	**2016**	**2017**	**2016**
Fair value of plan assets, January 1	$ 793.6	$ 781.7	$ 732.9	$ 720.1
Actual return on plan assets	128.4	68.1	110.4	60.5
Benefits paid	(72.4)	(56.2)	(62.0)	(47.7)
Fair value of plan assets, December 31	$ 849.6	$ 793.6	$ 781.3	$ 732.9

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. SCANA uses a dynamic investment strategy for the management of the pension plan assets. This strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2017 and 2016 and the target allocation for 2018 are as follows:

	Percentage of Plan Assets		
	Target Allocation	**December 31,**	
Asset Category	**2018**	**2017**	**2016**
Equity Securities	58%	58%	57%
Fixed Income	33%	31%	32%
Hedge Funds	9%	11%	11%

For 2018, the expected long-term rate of return on assets will be 7%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan’s historical cumulative actual returns over several periods, considers the expected active and passive returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2017 and 2016, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	The Company 2017	The Company 2016	Consolidated SCE&G 2017	Consolidated SCE&G 2016
Investments with fair value measure at Level 2:				
Mutual funds	$ 120	$ 125	$ 110	$ 115
Short-term investment vehicles	17	16	16	15
US Treasury securities	15	18	14	17
Corporate debt securities	91	82	84	76
Municipals	17	14	15	13
Total assets in the fair value hierarchy	260	255	239	236
Investments at net asset value:				
Common collective trust	498	453	458	418
Joint venture interests	92	86	84	79
Total investments at fair value	$ 850	$ 794	$ 781	$ 733

For all periods presented, assets with fair value measurements classified as Level 1 were insignificant, and there were no assets with fair value measurements classified as Level 3. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2017 or 2016.

Mutual funds held by the plan are open-ended mutual funds registered with the SEC. The price of the mutual funds' shares is based on its NAV, which is determined by dividing the total value of portfolio investments, less any liabilities, by the total number of shares outstanding. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. US Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Common collective trust assets and limited partnerships are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds' net assets at fair value by the units outstanding at each valuation date. Joint venture interests are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and not traded on a daily basis. The valuation of such multi-strategy hedge fund of funds is estimated based on the NAV of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may influence their fair value.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	The Company Pension Benefits	The Company Other Postretirement Benefits	Consolidated SCE&G Pension Benefits	Consolidated SCE&G Other Postretirement Benefits
2018	$ 66.9	$ 13.8	$ 66.9	$ 11.0
2019	64.6	14.6	64.6	11.7
2020	63.9	15.4	63.9	12.3
2021	66.5	16.0	66.5	12.8
2022	72.0	16.5	72.0	13.1
2023-2027	303.0	87.3	303.0	69.6

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals at the end of 2023, no significant contributions to the pension plan are expected to be made for the foreseeable future based on current market conditions and assumptions.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

The Company	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Service cost	$ 21.7	$ 20.7	$ 24.1	$ 4.5	$ 4.4	$ 5.3
Interest cost	37.4	39.4	38.2	11.5	12.1	11.4
Expected return on assets	(54.7)	(55.9)	(62.0)	n/a	n/a	n/a
Prior service cost amortization	1.6	3.9	4.1	—	0.3	0.4
Amortization of actuarial losses	16.3	14.8	13.6	1.0	0.5	2.1
Net periodic benefit cost	$ 22.3	$ 22.9	$ 18.0	$ 17.0	$ 17.3	$ 19.2

Consolidated SCE&G	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Service cost	$ 18.1	$ 16.9	$ 19.3	$ 3.7	$ 3.6	$ 4.4
Interest cost	31.9	33.4	32.2	9.5	9.9	9.4
Expected return on assets	(46.7)	(47.4)	(52.2)	n/a	n/a	n/a
Prior service cost amortization	1.4	3.4	3.4	—	0.3	0.3
Amortization of actuarial losses	13.9	12.5	11.4	0.8	0.4	1.7
Net periodic benefit cost	$ 18.6	$ 18.8	$ 14.1	$ 14.0	$ 14.2	$ 15.8

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

The Company	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Current year actuarial (gain) loss	$ (1.0)	$ 0.6	$ 2.7	$ 1.1	$ 0.8	$ (1.2)
Amortization of actuarial losses	(0.6)	(0.6)	(0.4)	(0.1)	—	(0.1)
Amortization of prior service cost	—	(0.1)	(0.1)	—	—	(0.1)
Total recognized in OCI	$ (1.6)	$ (0.1)	$ 2.2	$ 1.0	$ 0.8	$ (1.4)

Consolidated SCE&G	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Current year actuarial (gain) loss	$ 0.3	—	$ 0.2	$ 0.5	$ 0.3	$ (0.3)
Amortization of actuarial losses	(0.1)	$ (0.1)	(0.1)	—	—	—
Amortization of prior service cost	—	—	(0.1)	—	—	—
Total recognized in OCI	$ 0.2	$ (0.1)	—	$ 0.5	$ 0.3	$ (0.3)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

The Company	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Current year actuarial (gain) loss	$ (27.1)	$ 29.4	$ 9.2	$ 9.4	$ 11.1	$ (18.0)
Amortization of actuarial losses	(14.1)	(12.7)	(11.9)	(0.8)	(0.4)	(1.8)
Amortization of prior service cost	(1.4)	(3.4)	(3.7)	—	(0.3)	(0.3)
Total recognized in regulatory assets	$ (42.6)	$ 13.3	$ (6.4)	$ 8.6	$ 10.4	$ (20.1)

Consolidated SCE&G	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2017	2016	2015	2017	2016	2015
Current year actuarial (gain) loss	$ (24.8)	$ 26.3	$ 12.2	$ 7.3	$ 9.2	$ (14.0)
Amortization of actuarial losses	(12.5)	(11.2)	(10.4)	(0.7)	(0.3)	(1.5)
Amortization of prior service cost	(1.3)	(3.0)	(3.1)	—	(0.2)	(0.3)
Total recognized in regulatory assets	$ (38.6)	$ 12.1	$ (1.3)	$ 6.6	$ 8.7	$ (15.8)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Discount rate	4.22%	4.68%	4.20%	4.30%	4.78%	4.30%
Expected return on plan assets	7.25%	7.50%	7.50%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Health care cost trend rate	n/a	n/a	n/a	6.60%	7.00%	7.00%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2021	2021	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2018 are as follows for the Company. For Consolidated SCE&G such amounts are insignificant:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 0.5	$ 0.1

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2018 are as follows:

	The Company		Consolidated SCE&G	
Millions of Dollars	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 10.2	$ 1.8	$ 9.0	$ 1.5
Prior service cost	0.4	—	0.4	—
Total	$ 10.6	$ 1.8	$ 9.4	$ 1.5

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCANA sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. SCE&G participates in this plan. Contributions are matched 100% up to 6% of an employee's eligible earnings. Such matching contributions made by the Company totaled $27.9 million in 2017, $27.5 million in 2016 and $26.2 million in 2015. These matching contributions included those made by Consolidated SCE&G, which totaled $23.4 million in 2017, $22.9 million in 2016 and $21.8 million in 2015. Employee deferrals, matching contributions, and earnings on all contributions are fully vested and nonforfeitable at all times.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2015-2017, 2016-2018 and 2017-2019 performance cycles provide for performance measurement and award determination based on performance over a single three-year cycle, with payment of awards being deferred until after the end of the three-year performance cycle. In each of these performance cycles, 30% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash, and 70% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Cash-settled liabilities related to performance cycles totaled approximately $28.0 million in 2017, $18.4 million in 2016 and $20.8 million in 2015 for the Company and approximately $20.2 million in 2017, $13.2 million in 2016 and $6.3 million in 2015 for Consolidated SCE&G.

Fair value adjustments for all performance cycles resulted in compensation expense (benefit) recognized in the statements of operations totaling approximately $(9.0) million in 2017, $25.6 million in 2016 and $18.0 million in 2015 for the Company, of which approximately $(6.3) million in 2017, $17.3 million in 2016 and $12.2 million in 2015 for Consolidated SCE&G (including amounts allocated from SCANA Services). Such fair value adjustments also resulted in capitalized compensation costs of $(1.3) million in 2017, $3.3 million in 2016 and $2.3 million in 2015 for the Company and $(0.9) million in 2017, $3.1 million in 2016 and $0.6 million in 2015 for Consolidated SCE&G. At December 31, 2017, unrecognized compensation cost, which is expected to be recognized over a weighted-average period of 18 months, was $5.4 million for the Company and $4.1 million for Consolidated SCE&G. Large declines in stock price and relative performance in 2017 resulted in reductions of liabilities previously accrued with respect to open performance cycles. In the event of consummation of the merger, additional compensation cost arising from these liability awards may also be recognized.

10. COMMITMENTS AND CONTINGENCIES

Abandoned Nuclear Project

SCE&G, on behalf of itself and as agent for Santee Cooper, entered into the EPC Contract with the Consortium in 2008 for the design and construction of Unit 2 and Unit 3. SCE&G's ownership share in these units is 55%. As discussed below, various difficulties were encountered in connection with the project. The ability of the Consortium to adhere to established budgets and construction schedules was affected by many variables, including unanticipated difficulties encountered in connection with project engineering and the construction of project components, constrained financial resources of the contractors, regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected time frames, the availability of labor and materials at estimated costs and the efficiency of project labor. There were also contractor and supplier performance issues, difficulties in timely meeting critical regulatory requirements, contract disputes, and changes in key contractors or subcontractors. These matters, and others more fully discussed below, were the subject of comprehensive analyses performed by the Company and Santee Cooper (see Contractor Bankruptcy Proceedings and Related Uncertainties below). Based on the results of the Company's analysis, and in light of Santee Cooper's decision to suspend construction on Unit 2 and Unit 3, on July 31, 2017, the Company determined to stop the construction of the units and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means.

EPC Contract and BLRA Matters

The Nuclear Project and SCE&G's related recovery of financing costs through rates has been subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC approved, among other things, a milestone schedule and a capital costs estimates schedule for Unit 2 and Unit 3. Pursuant to the BLRA, this approval constituted a final and binding determination that the units were used and useful for utility purposes, and that the capital costs associated with them were prudent utility costs and expenses and were properly included in rates, so long as Unit 2 and Unit 3 were constructed or were being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the Nuclear Project. As of December 31, 2017, financing costs on $3.5 billion of SCE&G's construction costs for the Nuclear Project, excluding related transmission assets, have been reflected in revised rates under the BLRA, with the last revised rates increase having gone into effect in November 2016. SCE&G estimates that revised rates collections that have accumulated as of December 31, 2017, including collections related to transmission assets expected to be placed into service, total approximately $1.9 billion.

As a result of the decision to abandon the Nuclear Project, amounts reclassified from construction work in progress into regulatory assets, net of impairments described below, are summarized as follows:

Unrecovered Nuclear Project Costs		**Millions of dollars**
Nuclear Project costs as of September 30, 2017, prior to impairment loss and excluding transmission assets	$	4,730
Less Impairment loss recorded in the third quarter of 2017 (See below)		210
Balance of unrecovered Nuclear Project costs as of September 30, 2017		4,520
Less Impairment loss recorded in the fourth quarter of 2017 (See below)		460
Less Nuclear Project and switchyard assets transferred for use by Unit 1		84
Balance of unrecovered Nuclear Project costs as of December 31, 2017 (See Note 2)	$	3,976

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued combined Construction and Operating Licenses in March 2012. In November 2012, and again in September 2015 and November 2016 (see discussion below), the SCPSC approved SCE&G's requested updates to the milestone schedule, revised contractual substantial completion dates, and increases in capital and other costs. As further discussed below, under the current regulatory construct in South Carolina, approval by the SCPSC of cost recovery under the abandonment provisions of the BLRA or through other means will be required as a consequence of the Company's determination on July 31, 2017 to cease construction of the Nuclear Project.

October 2015 Amendment and WEC's Engagement of Fluor

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The amendment became effective in December 2015, at which time Fluor began serving as a subcontracted construction manager for the Consortium. The October 2015 Amendment provided SCE&G and Santee Cooper an option to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G's 55% portion being approximately $3.345 billion). This total amount to be paid would be reduced by amounts paid since June 30, 2015. SCE&G, on behalf of itself and as agent for Santee Cooper, elected the fixed price option, subject to SCPSC approval, on July 1, 2016.

Among other things, the October 2015 Amendment revised the contractual guaranteed substantial completion dates of Unit 2 and Unit 3 to August 31, 2019 and August 31, 2020, respectively, and provided for development of a revised construction milestone payment schedule. In February 2017, WEC notified the Company and Consolidated SCE&G that the contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively, which were reflected in the October 2015 Amendment, would not be met. Instead, WEC provided further revised estimated substantial completion dates of April 2020 and December 2020.

November 2016 SCPSC Order

In May 2016, SCE&G petitioned the SCPSC for approval of the updated construction and capital cost schedules for Unit 2 and Unit 3 which had been developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, the ORS and certain other parties concerning this petition. The

SCPSC also approved SCE&G's election of the fixed price option. By order dated February 28, 2017, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement, and that order was not appealed.

The construction schedule approved by the SCPSC in November 2016 provided for contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Unit 2 and Unit 3, respectively. The approved capital cost schedule included incremental capital costs that totaled $831 million, raising SCE&G's total project capital cost as then approved to an estimated amount of approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for the Nuclear Project from 10.5% to 10.25%. This revised ROE was to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. No such revised rates have been sought since that time.

Contractor Bankruptcy Proceedings and Related Uncertainties

On March 29, 2017, WEC and WECTEC, the two members of the Consortium, and certain of their affiliates filed petitions for protection under Chapter 11 of the U.S. Bankruptcy Code, citing a liquidity crisis arising from project contract losses attributable to the Nuclear Project and similar units being built for an unaffiliated company as a material factor that caused WEC and WECTEC to seek protection under the bankruptcy laws. As part of such filing, WEC and WECTEC publicly announced their inability to complete Unit 2 and Unit 3 under the terms of the EPC Contract.

In connection with the bankruptcy filing, SCE&G, Santee Cooper, WEC and WECTEC entered into an Interim Assessment Agreement under which engineering and construction continued on the project and under which SCE&G and Santee Cooper were provided the right to discuss project status with Fluor and other subcontractors and vendors and to obtain from them relevant project information and documents that had been previously contractually unavailable in order for SCE&G and Santee Cooper to perform comprehensive analyses regarding whether or how to proceed with the Nuclear Project. As part of the Interim Assessment Agreement, and to avoid an immediate rejection of the EPC Contract upon the filing of the bankruptcy case, WEC and WECTEC required SCE&G and Santee Cooper to make estimated weekly payments to WEC, WECTEC, subcontractors and vendors, irrespective of the fixed price provisions of the EPC Contract, to permit the time to conduct analyses. SCE&G and Santee Cooper agreed to pay specified costs incurred by the Consortium, Fluor, other subcontractors and vendors for work performed or services rendered while the Interim Assessment Agreement remained in effect.

During the period of the Interim Assessment Agreement, as amended and extended, SCE&G and Santee Cooper evaluated the various elements of the Nuclear Project, including forecasted costs and completion dates, while construction continued and SCE&G and Santee Cooper continued to make payments for such work.

As part of its evaluation, SCE&G considered that, as a result of the bankruptcy process (including WEC and WECTEC's public announcements that they could not perform under the terms of the EPC Contract), the EPC Contract would likely be rejected and that the benefit of the fixed-price terms provided by the EPC Contract would be lost. As such, any cost overruns that would have been absorbed by the Consortium would become the responsibility of SCE&G and Santee Cooper. Additionally, these cost increases and other costs identified by SCE&G would not be fully recoverable from the Consortium or from Toshiba under its payment guaranty or the related Toshiba Settlement, discussed below, and such costs would likely substantially exceed the amount of the Consortium's payment obligations guaranteed by Toshiba.

SCE&G also considered that even the newly revised substantial completion dates identified by WEC of April and December 2020 for Unit 2 and Unit 3, respectively, likely would not be met. As such, the electricity to be produced by each of the units would not qualify for nuclear production tax credits under Section 45J of the IRC. SCE&G's 55% share of these nuclear production tax credits for both Unit 2 and Unit 3 could have totaled as much as approximately$1.4 billion. Failure to meet the newly revised substantial completion dates identified by WEC would result in the nuclear production tax credits not being earned.

On September 1, 2017, SCE&G, for itself and as agent for Santee Cooper, filed with the Bankruptcy Court Proofs of Claim for unliquidated damages against each of WEC and WECTEC. The Proofs of Claim are based upon the anticipatory repudiation and material breach by the Consortium of the EPC Contract, and assert against WEC and WECTEC any and all claims that are based thereon or that may be related thereto. These claims were sold to Citibank on September 27, 2017 as part of the monetization transaction discussed below. Notwithstanding the sale of the claims, SCE&G and Santee Cooper remain responsible for any claims that may be made by WEC and WECTEC against them relating to the EPC Contract.

Toshiba Settlement and Subsequent Monetization

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and WECTEC, and in connection with the October 2015 Amendment, Toshiba, WEC's parent company, reaffirmed its guaranty of WEC's payment obligations. In satisfaction of such guaranty obligations, on July 27, 2017, the Toshiba Settlement was executed under which Toshiba was to make periodic settlement payments from October 2017 through September 2022 in the total amount of approximately $2.2 billion ($1.2 billion for SCE&G's 55% share). The $2.2 billion is subject to offset for payments by WEC that have the effect of satisfying the liens on the project discussed below.

On September 27, 2017, the scheduled payments under the Toshiba Settlement, exclusive of the payment due in October 2017, were purchased by Citibank for a one-time upfront payment of $1.847 billion (approximately $1.016 billion for SCE&G's 55% share), including amounts related to the contractor liens discussed below. The initial payment was then received from Toshiba on October 2, 2017, as scheduled, in the amount of $150 million ($82.5 million for SCE&G's 55% share). SCE&G's share of amounts received, net of certain expenses, total $1.095 billion. The purchase agreement provides that SCE&G and Santee Cooper (each according to its pro rata share) would indemnify Citibank for its losses arising from misrepresentations or covenant defaults under the purchase agreement. SCE&G and Santee Cooper also assigned their claims under the WEC bankruptcy process to Citibank, and agreed to use commercially reasonable efforts to cooperate with Citibank and provide reasonable support necessary for its enforcement of those claims. The proceeds received under or arising from the monetization of the Toshiba Settlement were recorded as cash and as a regulatory liability on the accompanying consolidated balance sheets, as the net value of the proceeds will be utilized to benefit SCE&G's customers in a manner to be determined by the SCPSC. While this determination is pending, SCE&G has utilized portions of the proceeds to repay maturing commercial paper balances, which short-term borrowings had been incurred primarily for the construction of Unit 2 and Unit 3 prior to the decision to stop their construction. See further discussion in Note 4.

A number of subcontractors and vendors to the Consortium have alleged non-payment by the Consortium for amounts owed for work performed on the Nuclear Project and have filed liens on property in Fairfield County, South Carolina, where Unit 2 and Unit 3 were to be located. SCE&G is contesting the filed liens. Payments under the Toshiba Settlement are subject to reduction if WEC pays creditors holding these liens directly. Under these circumstances, SCE&G and Santee Cooper, each in its pro rata share, would be required to make Citibank whole for the reduction. On January 2, 2018, the purchase agreement among SCE&G, Santee Cooper and Citibank was amended to limit the amount that SCE&G and Santee Cooper could be required to reimburse Citibank for valid subcontractor and vendor liens to $60 million ($33 million for SCE&G's 55% share).

Determination to Stop Construction and Related Regulatory, Political and Legal Developments

The BLRA provides that, in the event of abandonment prior to plant completion, costs incurred, including AFC, and a return on those costs, may be recoverable through rates, if the SCPSC determines that the decision to abandon the Nuclear Project was prudent. Based on the evaluation previously discussed, and in light of Santee Cooper's decision to suspend construction, on July 31, 2017, the Company determined to stop construction of Unit 2 and Unit 3 and to pursue recovery of costs incurred in connection with such construction under the abandonment provisions of the BLRA or through other means. On July 31, 2017, SCE&G gave WEC a five-day notice of termination of the Interim Assessment Agreement and notified WEC of its determination to stop construction of Unit 2 and Unit 3.

On August 1, 2017, SCE&G senior management provided an allowable ex parte briefing to the SCPSC regarding the Nuclear Project and this decision, and SCE&G also filed a petition with the SCPSC which included its plan of abandonment and certain proposed actions which would mitigate related customer rate increases, including a proposal to return to customers the net value of proceeds received by SCE&G under or arising from the monetization of the Toshiba Settlement. Through this petition, SCE&G had sought recovery of such costs expended on the construction of the Nuclear Project, including certain costs incurred subsequent to SCE&G's last revised rates update, and certain other costs under the abandonment provisions of the BLRA. Subsequently, SCE&G's management met with various stakeholders and members of the South Carolina General Assembly, including legislative leaders, to discuss the abandonment of the Nuclear Project and to hear their concerns. In response to those concerns, and to allow for adequate time for governmental officials to conduct their reviews, SCE&G voluntarily withdrew its petition to abandon the project from the SCPSC on August 15, 2017.

In August 2017, special committees of the South Carolina General Assembly, both in the House of Representatives and in the Senate, began conducting public hearings regarding the decision to abandon the Nuclear Project. Members of SCE&G's senior management, along with representatives from Santee Cooper, the ORS and other interested parties, testified before these committees. Several legislative proposals adverse to the Company and Consolidated SCE&G resulted from the work of these committees and certain adverse proposals have been or are being considered by the General Assembly in 2018. In January 2018, these committees reconvened for the purpose of considering the effects of the proposed merger discussed below on Nuclear Project stakeholders. On January 31, 2018, the South Carolina House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

In September 2017, the Company was served with a subpoena issued by the United States Attorney's Office for the District of South Carolina seeking documents relating to the Nuclear Project. The subpoena requires the Company to produce a broad range of documents related to the project. Also in September 2017, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. In October 2017, the staff of the SEC's Division of Enforcement also issued a subpoena for documents related to an investigation they are conducting related to the Nuclear Project. The Company and Consolidated SCE&G intend to fully cooperate with these investigations. Also in connection with the abandonment of the Nuclear Project, various state or local governmental authorities have attempted and may further attempt to challenge, reverse or revoke one or more previously-approved tax or economic development incentives, benefits or exemptions and may attempt to apply such action retroactively. No assurance can be given as to the timing or outcome of these matters.

On September 26, 2017, the South Carolina Office of Attorney General issued an opinion stating, among other things, that "as applied, portions of the BLRA are constitutionally suspect," including the abandonment provisions. Also on September 26, 2017, the ORS filed the Request with the SCPSC asking for an order directing SCE&G to immediately suspend all revised rates collections from customers which were previously approved by the SCPSC pursuant to the authority of the BLRA. In the Request, the ORS relied upon the opinion from the Office of Attorney General to assert that it is not just and reasonable or in the public interest to allow SCE&G to continue collecting revised rates. Further, the ORS noted the existence of an allegation that SCE&G failed to disclose information to the ORS that should have been disclosed and that would have appeared to provide a basis for challenging prior requests, and asserted that SCE&G should not be allowed to continue to benefit from nondisclosure. The ORS also asked for an order that, if the BLRA is found to be unconstitutional or the South Carolina General Assembly amends or revokes the BLRA, then SCE&G should make credits to future bills or refunds to customers for prior revised rates collections. SCE&G estimates that revised rates collections, including collections related to transmission assets expected to be placed into service, currently total approximately $445 million annually, and such amounts accumulated as of December 31, 2017 total approximately $1.9 billion.

On September 28, 2017, SCE&G filed a Motion to Dismiss the Request and a Request for Briefing Schedule and Hearing on Motion to Dismiss. On September 28, 2017, the SCPSC deferred action on the Request and ordered a hearing officer to establish a briefing schedule and hearing date on SCE&G's motion. On October 17, 2017, the ORS filed a motion with the SCPSC to amend the Request, in which the ORS asked the SCPSC to consider the most prudent manner by which SCE&G will enable its customers to realize the value of the monetized Toshiba Settlement payments and other payments made by Toshiba towards satisfaction of its obligations to SCE&G. Parties who filed to intervene in the matter or who filed a letter in support of the request by the ORS include the Governor, the state's Office of Attorney General and Speaker of the House of Representatives, the Electric Cooperatives of South Carolina, the SCEUC, certain large industrial customers, and several environmental groups. After conducting a hearing to consider SCE&G's motion, the SCPSC denied the motion on December 20, 2017 and requested that the ORS carry out an inspection, audit and examination of SCE&G's revenue requirements to assist the SCPSC in determining whether SCE&G's present schedule of rates is fair and reasonable and also ordered that a hearing be scheduled to consider the Request. The hearing has not yet been scheduled. SCE&G intends to continue vigorously contesting the Request, but cannot give any assurance as to the timing or outcome of this matter. See also Note 2.

Proposals to Resolve Outstanding Issues

On November 16, 2017, SCE&G announced for public consideration a proposal to resolve outstanding issues relating to the Nuclear Project. Under the proposal, SCE&G electric customers were to receive a 3.5% electric rate reduction, the addition of an existing 540-MW natural gas fired power plant by SCE&G with the acquisition cost borne by SCANA shareholders, and the addition of approximately 100-MW of large scale solar energy by SCE&G. The proposal also provided for the recovery of the nuclear construction costs (net of the proceeds of the Toshiba Settlement not utilized for liquidation of project liens) over 50 years. While SCE&G's proposal was not formally submitted for regulatory approval, discussions with key stakeholders over the ensuing weeks indicated that SCE&G's proposal would not be sufficient to resolve the outstanding issues.

On January 2, 2018, SCANA entered into the Merger Agreement with Dominion Energy, and on January 12, 2018, SCE&G and Dominion Energy filed the Joint Petition requesting SCPSC approval of the merger or a finding that either the merger is in the public interest or that there is an absence of harm arising from the merger. In this petition, the parties commit to providing an up-front, one time rate credit to SCE&G's electric customers totaling approximately $1.3 billion within 90 days of the merger's closing, providing at least a 5% reduction in customer bills, shortening the amortization period for costs related to the Nuclear Project to 20 years, forgoing recovery of approximately $1.7 billion in costs related to the Nuclear Project, and adding an existing 540-MW natural gas fired power plant by SCE&G with no initial investment borne by customers. No assurance can be given as to the timing or outcome of efforts to consummate the Merger Agreement or to obtain approval of the Joint Petition.

Impairment Considerations

Under the current regulatory construct in South Carolina, pursuant to the BLRA or through other means, the ability of SCE&G to recover costs incurred in connection with Unit 2 and Unit 3, and a reasonable return on them, will be subject to review and approval by the SCPSC. In light of the contentious nature of the reviews by legislative committees and others, the adverse impact that would result if proposed legislation is enacted, and the Request being considered by the SCPSC that could result in the suspension of rates currently being collected under the BLRA, as well as the return of such amounts previously collected, there is significant uncertainty as to SCE&G's ultimate ability to fully recover its costs of Unit 2 and Unit 3 and a return on them from its customers. SCE&G continues to contest the specific challenges described above. However, based on the consideration of those challenges, and particularly in light of SCE&G's proposed solution announced on November 16, 2017 and details in the Joint Petition filed by SCE&G and Dominion Energy with the SCPSC on January 12, 2018, the Company and Consolidated SCE&G have determined that a disallowance of recovery of part of the cost of the abandoned plant is both probable and reasonably estimable under applicable accounting guidance. In addition, the Company and Consolidated SCE&G have determined that full recovery of certain other related costs deferred within regulatory assets is less than probable. As a result, as of December 31, 2017, the Company and Consolidated SCE&G have recognized a pre-tax impairment loss totaling $1.118 billion ($690 million net of tax). With the exception of the $210 million loss recorded in the third quarter of 2017 as explained below, this impairment loss was recorded in the fourth quarter of 2017. A discussion of this impairment loss follows:

- A pre-tax impairment loss was recorded with respect to disallowance of unrecovered nuclear project costs of approximately $670 million. This amount includes $210 million recorded in the third quarter of 2017, which represented costs of approximately $1.2 billion that had been expended on the project, exclusive of transmission costs, but which had not yet been determined to be prudent by the SCPSC in connection with revised rates proceedings under the BLRA, offset by the amount of approximately $1 billion, which amount represents the recovery of the Toshiba Settlement proceeds that are in excess of amounts from that settlement that the Company and Consolidated SCE&G estimated may be necessary to satisfy certain project liens. This impairment loss also includes $180 million, which amount arises from SCE&G's entry into an agreement in the fourth quarter of 2017 to purchase in 2018 an existing 540-MW combined cycle gas generating station along with SCE&G's commitment to regulators and the public that the recovery of the initial capital investment in the facility would not be sought from customers. The remaining $280 million of this impairment loss was recorded after consideration of the regulatory and political developments described above.
- A pre-tax impairment loss was recorded in the aggregate amount of $361 million to write off costs which had been previously deferred, primarily as regulatory assets, in connection with the Nuclear Project. Such regulatory assets included deferred losses on interest rate swaps for which debt will not be issued due to the abandonment of the Nuclear Project, carrying costs on deferred tax assets arising from the capitalization of interest costs for tax purposes, net deferred costs and tax benefits related to foregone domestic production activities deductions (net of uncertain tax positions and credits) taken with respect to the project, and taxes associated with equity AFC.
- Finally, an $87 million pre-tax impairment loss was recorded in order to reduce to estimated fair value the carrying value of nuclear fuel acquired for use in Unit 2 and Unit 3.

With the exception of the $87 million related to nuclear fuel, the above impairment loss reflects impacts similar to those that may have resulted had the proposed solution announced November 16, 2017 been implemented. That proposal is presented by SCE&G as a less-favored alternative to the merger benefits and cost recovery plan in the January 12, 2018 Joint

Petition. It is reasonably possible that a change in the estimated impairment loss could occur in the near term. If the merger benefits and cost recovery plan outlined in the Joint Petition is implemented (upon closing of the merger as contemplated in the Merger Agreement), an additional impairment loss and other charges totaling as much as approximately $1.7 billion would be expected to be recorded. This additional impairment loss would result from the write-off of unrecovered Nuclear Project costs of approximately $856 million recorded within regulatory assets and the recording of additional liabilities for customer refunds totaling approximately $1.875 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. If instead the Joint Petition is not approved and the Request by the ORS is approved, and if the BLRA is found to be unconstitutional or the General Assembly amends or revokes the BLRA, the Company and Consolidated SCE&G may be required to record an additional impairment loss and other charges totaling as much as approximately $4.8 billion. This additional impairment loss would result from the write-off of the remaining unrecovered Nuclear Project costs of $3.976 billion recorded within regulatory assets and the refund of revised rates collections under the BLRA described above of approximately $1.9 billion, net of approximately $1.062 billion, which amount represents the monetization of guaranty settlement of $1.095 billion recorded within regulatory liabilities less amounts that may be required to settle contractor liens. The Company and Consolidated SCE&G do not currently anticipate that any of the $1.9 billion in revenue previously collected will be subject to refund; however, no assurance can be given as to the outcome of this matter.

Liquidity Considerations

As a result of the decision to stop construction of Unit 2 and Unit 3, downgrades by credit ratings agencies have recently occurred. The Company and Consolidated SCE&G have significant obligations that must be paid within the next 12 months, including long-term debt maturities and capital lease payments of $727 million for the Company (including $723 million for Consolidated SCE&G), short-term borrowings of $350 million for the Company (including $252 million for Consolidated SCE&G), interest payments of approximately $335 million for the Company (including $259 million for Consolidated SCE&G), and future minimum payments for operating leases of $34 million for the Company (including $26 million for Consolidated SCE&G). Working capital requirements, such as those for fuel supply and similar obligations, also arise due to the lag between when such amounts are paid and when related collection of such costs through customer rates occurs.

Management believes as of the date of issuance of these financial statements that it has access to available sources of cash to pay obligations when due over the next 12 months. These sources include committed, long-term lines of credit that expire in December 2020 totaling $1.8 billion for the Company (including $1.2 billion for Consolidated SCE&G). In addition, as of the date of issuance of these financial statements, SCE&G continues to collect in customer rates amounts previously approved under the BLRA, as well as amounts provided for in other orders related to non-BLRA electric and gas rates. However, as further described below, SCANA's credit rating has fallen below investment grade, which has constricted its ability and that of Consolidated SCE&G to issue commercial paper.

As described above, on January 31, 2018, the South Carolina House of Representatives passed a bill (H. 4375) that would create an experimental rate which would effectively suspend collections from rates previously approved by the SCPSC under the BLRA. This experimental rate would remain in effect during the pendency of administrative proceedings currently before the SCPSC or any appeal therefrom. In addition, the South Carolina Senate passed a joint resolution (S. 954) which, if enacted, would prohibit the SCPSC from holding a hearing on the merits for a docket in which requests were made pursuant to the BLRA (other than an administrative or procedural hearing prior to such hearing on the merits), and would prohibit any final determination on any such requests, before November 1, 2018, and would require the SCPSC to issue a final order for such docket no later than December 21, 2018. Any bill must be approved by both legislative chambers and be signed by, or allowed to become law without the signature of, the Governor before it would be enacted. Such regulatory, legislative or judicial proceedings outside of the Company’s and Consolidated SCE&G’s control may result in the temporary or permanent suspension of the approximately $445 million annually of rates being collected currently under the BLRA, the return of such amounts previously collected of $1.9 billion, or the requirement that SCE&G's share of payments received from the Toshiba Settlement ($1.095 billion) be placed in escrow or be refunded to customers. Neither the Company nor Consolidated SCE&G can predict if or when either of these bills could become law or what additional actions, if any, may be proposed or taken, including other legislative actions related to the BLRA.

Were the SCPSC to grant the relief sought by the ORS in the Request or grant similar relief resulting from legislative action, and as further discussed above in Impairment Considerations, an additional impairment loss or other charges totaling as much as approximately $4.8 billion may be required. Such an impairment loss or other charges would further stress the Company’s and Consolidated SCE&G’s equity to total capitalization ratio and may result in the Company’s and Consolidated SCE&G’s ratio of equity to total capitalization falling below minimum levels prescribed in the Company’s credit agreements. In such an event, the Company’s and Consolidated SCE&G’s ability to borrow under their commercial paper programs and credit facilities and their ability to pay future dividends would likely be limited or may trigger events of default under such agreements.

Known and knowable conditions and events when considered in the aggregate as of the date of issuance of these financial statements do not suggest it is probable that the Company and Consolidated SCE&G will not be able to meet obligations as they come due over the next 12 months. However, possible future actions related to rates or refunds could have a material adverse effect on the Company's and Consolidated SCE&G's financial condition, liquidity, results of operations and cash flows such that management's conclusion with respect to its ability to pay obligations when due could change.

Claims and Litigation

Following the Company's decision to stop construction of Unit 2 and Unit 3, putative derivative and class action lawsuits have been filed in multiple state circuit courts and federal district court on behalf of customers, shareholders and SCANA (in the case of the derivative shareholder actions), against SCANA, SCE&G, or both, and in certain cases some of their officers and/or directors. The plaintiffs allege various causes of action, including but not limited to waste, breach of fiduciary duty, negligence, unfair trade practices, unjust enrichment, conspiracy, fraud, constructive fraud, misrepresentation and negligent misrepresentation, promissory estoppel, constructive trust, and money had and received, among other causes of action. Plaintiffs generally seek compensatory and consequential damages and statutory treble damages and such further relief as the court deems just and proper. In addition, certain plaintiffs seek a declaration that SCE&G may not charge its customers to reimburse itself for past and continuing costs of the Nuclear Project. Certain plaintiffs also seek to freeze or appoint a receiver for certain of SCE&G's assets, including all money SCE&G has received under the Toshiba payment guaranty and related settlement agreement and money to be collected from customers for the Nuclear Project.

Putative class action lawsuits have been filed on behalf of investors in federal court against SCANA and certain of its current and former executive officers and directors. The plaintiffs allege, among other things, that defendants violated Section 10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder, and two suits allege violations of the Racketeer Influenced and Corrupt Organizations Act. In one suit, plaintiff alleges that director defendants violated Section 14(a) of the Exchange Act and SEC Rule 14a-9 by allowing or causing misleading proxy statements to be issued. The plaintiffs in each of these suits seek compensatory and consequential damages and such further relief as the court deems proper.

Lawsuits seeking class action status have also been filed on behalf of investors in the Court of Common Pleas in the Counties of Lexington and Richland, South Carolina, against SCANA, its CEO and directors, Dominion Energy and Sedona Corp. The plaintiffs allege, among other things, that defendants violated their fiduciary duties to shareholders by executing a merger agreement that unfairly deprived plaintiffs of the true value of their SCANA stock, and that Dominion Energy and Sedona Corp. aided and abetted these actions. Among other remedies, the plaintiffs in each case seek to enjoin the merger and rescind the Merger Agreement. In addition, two of the lawsuits seek in the alternative, should the merger be completed, an award of unspecified monetary damages.

A complaint has been filed by Fairfield County against SCE&G making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of the implied duty of good faith and fair dealing, and unfair trade practices related to SCE&G's termination of the FILOT agreement. Plaintiff seeks injunctive relief to prevent SCE&G from terminating the FILOT agreement; actual and consequential damages; treble damages; punitive damages; and attorneys' fees.

The Company has also been served with subpoenas issued by the United States Attorney's Office for the District of South Carolina and the staff of the SEC's Division of Enforcement seeking documents relating to the Nuclear Project. In addition, the state's Office of Attorney General, the Speaker of the House of Representatives, and the Chair and Vice-Chair of the South Carolina House Utility Ratepayer Protection Committee have requested that SLED conduct a criminal investigation into the handling of the Nuclear Project by SCANA and SCE&G. The Company and Consolidated SCE&G intend to fully cooperate with any such investigations.

On January 26, 2018, the DOR notified the Company that it was initiating an audit of the Company's sales and use tax returns for the periods September 1, 2008 through December 31, 2017. Based on an introductory meeting regarding that audit on February 8, 2018, the Company understands that the DOR's position is that the exemption for sales and use tax for purchases related to the Nuclear Project should not apply because Unit 2 and Unit 3 will not be placed into service and no electricity will be manufactured for sale. The Company intends to vigorously contest the DOR's position.

While the Company and Consolidated SCE&G intend to vigorously contest the lawsuits, claims, and audit positions which have been filed or initiated against them, they cannot predict the timing or outcome of these matters or others that may arise, and adverse outcomes from some of these matters would not be covered by insurance. As noted above, the various claims for damages do not specify an amount for those damages and the number of plaintiffs that are ultimately certified in the potential class actions lawsuits is unknown. In addition, each of the cases referred to above is in its early stages. For these reasons, the Company and Consolidated SCE&G cannot provide any estimate or range of potential loss for these matters at this time, and no accrual for these potential losses has been included in the consolidated financial statements. However, outcomes could have a material adverse effect on the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G are subject to various other claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on the Company's and Consolidated SCE&G's results of operations, cash flows or financial condition.

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Unit 1. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $450 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G’s maximum assessment, based on its two-thirds ownership of Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin and up to $2.33 billion resulting from an event of a non-nuclear origin. The NEIL policies in aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. The NEIL policies permit retrospective assessments under certain conditions to cover insurer’s losses. Based on the current annual premium, SCE&G’s portion of the retrospective premium assessment would not exceed $22.3 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Unit 1 for property damage and outage costs up to $415 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $2.0 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on the Company’s and Consolidated SCE&G's results of operations, cash flows and financial position.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, the Company and Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company and Consolidated SCE&G expect to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at its coal-fired electric generating plants. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future.

On August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule included state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030, and established a phased-in compliance approach beginning in 2022. The rule gave each state from one to three years to issue its SIP, which would ultimately define the specific compliance methodology that would be applied to existing units in that state. On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. As a result of an Executive Order on March 28, 2017, the EPA placed the rule under review and the Court of Appeals agreed to hold the case in abeyance. On October 10, 2017, the Administrator of the EPA signed a notice proposing to repeal the rule on the grounds that it exceeds the EPA's statutory authority. In a separate but related action, the EPA issued an Advance Notice of Proposed Rulemaking on December 18, 2017, to solicit information from the public about a potential future rulemaking to limit greenhouse gas emissions from existing units. The Company and Consolidated SCE&G expect any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual SO_2 emissions and annual and ozone season NO_X emissions to assist in attaining the ozone and fine particle National Ambient Air Quality Standards. The rule establishes an emissions cap for SO_2 and NO_X and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. The State of South Carolina has chosen to remain in the CSAPR program, even though recent court rulings exempted the state. This allows the state to remain compliant with regional haze standards. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any costs incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The MATS rule has been the subject of ongoing litigation even while it remains in effect. Rulings on this litigation are not expected to have an impact on SCE&G or GENCO due to plant retirements, conversions, and enhancements. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits such that, as a facility's NPDES permit is renewed, any new effluent limitations would be incorporated. The ELG Rule had become effective on January 4, 2016, after which state regulators could modify facility NPDES permits to match more restrictive standards, which would require facilities to retrofit with new wastewater treatment technologies. Compliance dates varied by type of wastewater, and some were based on a facility's five-year permit cycle and thus could range from 2018 to 2023. However, the ELG Rule is under reconsideration by the EPA and has been stayed administratively. The EPA has decided to conduct a new rulemaking that could result in revisions to certain flue gas desulfurization wastewater and bottom ash transport water requirements in the ELG Rule. Accordingly, in September 2017 the EPA finalized a rule that resets compliance dates under the ELG Rule to a range from November 1, 2020 to December 31, 2023. The EPA indicates that the new rulemaking process may take up to three years to complete, such that any revisions to the ELG Rule likely would not be final until the summer of 2020. While the Company and Consolidated SCE&G expect that wastewater treatment technology retrofits will be required at Williams and Wateree Stations, any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications to ensure compliance with this rule. Any costs incurred to comply with this rule are expected to be recoverable through rates.

The EPA's final rule for CCR became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. SCE&G has three ponds and three landfills that are governed by the CCR rule. The Company and Consolidated SCE&G do not expect the incremental compliance costs associated with this rule to be significant and expect to recover such costs in future rates.

In December 2016, the U.S. Congress passed and the President signed legislation that creates a framework for EPA- approved state CCR permit programs. Under this legislation, an approved state CCR permit program functions in lieu of the self-implementing Federal CCR rule. The legislation allows states more flexibility in developing permit programs to implement the environmental criteria in the CCR rule. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. To date, South Carolina has not begun drafting a CCR rule.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2016, the federal government has not accepted any spent fuel from Unit 1, and it remains unclear when the repository may become available. SCE&G has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2019 and will cost an additional $9.9 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2017, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $24.6 million and are included in regulatory assets.

Operating Lease Commitments

The Company and Consolidated SCE&G are obligated under various operating leases for land, office space, furniture, equipment, rail cars, a purchase power agreement, and for the Company, airplanes. Leases expire at various dates through 2057.

	Rent Expense		
Millions of dollars	**2017**	**2016**	**2015**
The Company	$ 10.0	$ 10.2	$ 11.1
Consolidated SCE&G	11.4	12.2	12.3

	Future Minimum Rental Payments					
Millions of dollars	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
The Company	$ 34	$ 30	$ 6	$ 6	$ 5	$ 31
Consolidated SCE&G	26	23	1	1	—	17

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is not probable; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2017, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.8 billion.

Asset Retirement Obligations

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2017, SCE&G has recorded AROs of approximately $208 million for nuclear plant decommissioning (see Note 1). In addition, the Company has recorded AROs of approximately $360 million, including $321 million for Consolidated SCE&G, for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	**2017**	**2016**	**2017**	**2016**
Beginning balance	$ 558	$ 520	$ 522	$ 488
Liabilities incurred	—	—	—	—
Liabilities settled	(10)	(11)	(9)	(11)
Accretion expense	25	23	23	22
Revisions in estimated cash flows	(5)	26	(7)	23
Ending balance	$ 568	$ 558	$ 529	$ 522

Revisions in estimated cash flows in 2017 primarily related to ash pond retirement obligations settled and updates in the timing of cash flows as work is completed. Such revisions in 2016 related to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study.

11. AFFILIATED TRANSACTIONS

The Company:

The Company received cash distributions from equity-method investees of $2.8 million in 2017, $3.7 million in 2016 and $4.0 million in 2015. The Company made investments in equity-method investees of $4.6 million in 2017, $5.5 million in 2016 and $4.1 million in 2015.

The Company and Consolidated SCE&G:

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. The net of the total purchases and total sales are recorded in Other expenses on the consolidated statements of operations (for the Company) and of comprehensive income (for Consolidated SCE&G).

Millions of Dollars	2017	2016	2015
Purchases from Canadys Refined Coal, LLC	$ 162.1	$ 161.8	$ 233.2
Sales to Canadys Refined Coal, LLC	161.1	160.8	232.0

Millions of Dollars	2017	2016
Receivable from Canadys Refined Coal, LLC	$ 4.9	$ 16.0
Payable to Canadys Refined Coal, LLC	4.9	16.1

Consolidated SCE&G:

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy to serve its retail gas customers and for certain electric generation requirements.

SCANA Services, on behalf of itself and its parent company, provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative, and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services include amounts capitalized. Amounts expensed are recorded in Other operation and maintenance - nonconsolidated affiliate and Other expenses on the consolidated statements of comprehensive income (loss).

Millions of Dollars	2017	2016	2015
Purchases from SCANA Energy	$ 127.4	$ 111.5	$ 128.5
Direct and Allocated Costs from SCANA Services	302.8	337.7	300.0

Millions of Dollars	2017	2016
Payable to SCANA Energy	$ 10.0	$ 8.8
Payable to SCANA Services	42.0	63.5

Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in 2015.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs is described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1. Intersegment sales and transfers of electricity and gas are recorded based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively. Gas Marketing is comprised of the marketing operations of SCANA Energy, which markets natural gas to retail customers in Georgia and to industrial and large commercial customers and municipalities in the Southeast.

All Other includes the parent company and a services company. In addition, All Other includes gains from the sales of CGT and SCI (see Note 1) and their operating results prior to their sale in the first quarter of 2015. CGT and SCI were nonreportable segments during all periods presented. External revenue and intersegment revenue for All Other related to CGT and SCI were not significant during any period presented.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. Gas Marketing operates in a deregulated environment.

Management uses operating income (loss) to measure segment profitability for its regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, no allocation is made to segments for interest charges, income tax expense (benefit) or assets other than utility plant. For nonregulated operations, management uses net income (loss) as the measure of segment profitability and evaluates total assets for financial position. Intersegment revenue for SCE&G was not significant. Interest income is not reported by segment and is not material. Deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income (loss) consist of the unallocated net income (loss) of regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense (Benefit), Expenditures for Assets and Deferred Tax Assets include primarily the amounts that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs, and totals not allocated to other segments. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Disclosure of Reportable Segments

The Company:

Millions of dollars	Electric Operations	Gas Distribution	Gas Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2017						
External Revenue	$ 2,659	$ 874	$ 874	—	—	$ 4,407
Intersegment Revenue	5	2	127	$ 389	$ (523)	—
Operating Income (Loss)	(161)	186	n/a	—	51	76
Interest Expense	19	28	1	—	315	363
Depreciation and Amortization	295	85	2	16	(16)	382
Income Tax Expense (Benefit)	8	41	25	(7)	(179)	(112)
Net Income (Loss)	n/a	n/a	27	(46)	(100)	(119)
Segment Assets	11,979	3,259	230	1,042	2,229	18,739
Expenditures for Assets	216	417	2	7	583	1,225
Deferred Tax Assets	6	25	9	—	(40)	—
2016						
External Revenue	$ 2,614	$ 788	$ 825	—	—	$ 4,227
Intersegment Revenue	5	2	111	$ 414	$ (532)	—
Operating Income	957	148	n/a	—	48	1,153
Interest Expense	17	25	1	—	299	342
Depreciation and Amortization	287	82	2	16	(16)	371
Income Tax Expense	8	32	19	—	212	271
Net Income (Loss)	n/a	n/a	30	(18)	583	595
Segment Assets	11,929	2,892	230	1,124	2,532	18,707
Expenditures for Assets	1,275	276	2	11	15	1,579
Deferred Tax Assets	9	32	11	—	(52)	—
2015						
External Revenue	$ 2,551	$ 810	$ 1,018	$ 5	$ (4)	$ 4,380
Intersegment Revenue	6	2	128	413	(549)	—
Operating Income	876	152	n/a	236	44	1,308

Interest Expense	17	23	1	1	276	318
Depreciation and Amortization	277	77	2	16	(14)	358
Income Tax Expense	9	32	18	1	333	393
Net Income (Loss)	n/a	n/a	28	185	533	746
Segment Assets	10,883	2,606	201	998	2,458	17,146
Expenditures for Assets	1,087	203	2	15	(154)	1,153
Deferred Tax Assets	5	29	15	—	(49)	—

Consolidated SCE&G:

Millions of dollars	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2017				
External Revenue	$ 2,664	$ 406	—	$ 3,070
Operating Income (Loss)	(161)	71	—	(90)
Interest Expense	19	—	$ 269	288
Depreciation and Amortization	295	30	(13)	312
Segment Assets	11,979	869	3,098	15,946
Expenditures for Assets	216	65	647	928
Deferred Tax Assets	6	n/a	(6)	—
2016				
External Revenue	$ 2,619	$ 367	—	$ 2,986
Operating Income	957	56	—	1,013
Interest Expense	17	—	$ 253	270
Depreciation and Amortization	287	28	(13)	302
Segment Assets	11,929	825	3,337	16,091
Expenditures for Assets	1,275	78	46	1,399
Deferred Tax Assets	9	n/a	(9)	—
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	876	58	—	934
Interest Expense	17	—	$ 231	248
Depreciation and Amortization	277	28	(11)	294
Segment Assets	10,883	757	3,125	14,765
Expenditures for Assets	1,087	57	(136)	1,008
Deferred Tax Assets	5	n/a	(5)	—

13. OTHER INCOME (EXPENSE), NET

Components of other income (expense), net are as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	2017	2016	2015	2017	2016	2015
Other income	$ 79	$ 64	$ 75	$ 45	$ 29	$ 31
Other expense	(46)	(38)	(60)	(25)	(24)	(31)
Allowance for equity funds used during construction	23	29	27	15	26	25
Other income (expense), net	$ 56	$ 55	$ 42	$ 35	$ 31	$ 25

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

The Company **Millions of dollars, except per share amounts**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
2017					
Total operating revenues	$ 1,173	$ 1,001	$ 1,076	$ 1,157	$ 4,407
Operating income (loss)	316	249	120	(609)	76
Net Income (Loss)	171	121	34	(445)	(119)
Earnings (Loss) per share	1.19	0.85	0.24	(3.11)	(0.83)
2016					
Total operating revenues	$ 1,172	$ 905	$ 1,093	$ 1,057	$ 4,227
Operating income	331	221	348	253	1,153
Net Income	176	105	189	125	595
Earnings per share	1.23	0.74	1.32	0.87	4.16

Consolidated SCE&G **Millions of dollars**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
2017					
Total operating revenues	$ 719	$ 756	$ 856	$ 739	$ 3,070
Operating income (loss)	222	246	123	(681)	(90)
Net Income (Loss)	112	126	42	(452)	(172)
Earnings Available (Loss Attributable) to Common Shareholder	109	123	39	(456)	(185)
2016					
Total operating revenues	$ 717	$ 692	$ 882	$ 695	$ 2,986
Operating income	236	222	359	196	1,013
Net Income	116	113	204	93	526
Earnings Available to Common Shareholder	113	110	201	89	513

See Note 10 for a discussion of the impairment loss that was booked in the third quarter and the fourth quarter of 2017.

15. SUBSEQUENT EVENT

On January 2, 2018, SCANA, Sedona Corp. and Dominion Energy entered into the Merger Agreement pursuant to which Sedona Corp. (a wholly-owned subsidiary of Dominion Energy) agreed to merge into SCANA in a stock-for-stock transaction in which SCANA shareholders would receive 0.6690 of a share of Dominion Energy common stock for each share of SCANA common stock. The completion of the merger is subject to a variety of closing conditions, including the receipt of approvals from SCANA's shareholders and is also subject to consents and approvals or findings from governmental entities, which may impose conditions that could have an adverse effect on the Company or Consolidated SCE&G or could cause either SCANA or Dominion Energy to abandon the merger. The completion of the merger is also subject to an absence of substantive changes in certain South Carolina laws, including the BLRA, that would reasonably be expected to have an adverse effect on SCANA or its subsidiaries, or if any governmental entity enacts any order or there is any change in law which imposes any material change to the terms, conditions or undertakings set forth in the Joint Petition or any significant changes to the economic value of the Joint Petition. See also Note 10.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2017, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCANA's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2017, SCANA's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2017, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCANA's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2017. There has been no change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2017 that has materially affected or is reasonably likely to materially affect SCANA's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA's internal control system was designed by or under the supervision of SCANA's management, including its CEO and CFO, to provide reasonable assurance to SCANA's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA's management assessed the effectiveness of SCANA's internal control over financial reporting as of December 31, 2017. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA's management believes that, as of December 31, 2017, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on SCANA's internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2017, of the Company and our report dated February 22, 2018, expressed an unqualified opinion on those financial statements and financial statement schedule and included an emphasis-of-matter paragraph regarding legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company as a result of the abandoned Nuclear Project.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2017, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2017, SCE&G's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2017, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCE&G's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2017. There has been no change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2017 that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G's internal control system was designed by or under the supervision of SCE&G's management, including its CEO and CFO, to provide reasonable assurance to SCE&G's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G's management assessed the effectiveness of SCE&G's internal control over financial reporting as of December 31, 2017. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).* Based on this assessment, SCE&G's management believes that, as of December 31, 2017, internal control over financial reporting is effective based on those criteria.

ITEM 9B. OTHER INFORMATION

Not Applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report on Form 10-K at page 34. As permitted by Form 10-K General Instruction G(3), the other information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: As permitted by Form 10-K General Instruction G(3), the information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: As permitted by Form 10-K General Instruction G(3), the information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

Equity securities issuable under SCANA’s compensation plans at December 31, 2017 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)		(b)	(c)
Equity compensation plans approved by security holders:				
2015 Long-Term Equity Compensation Plan	454,023	(1)	n/a	4,545,977
Non-Employee Director Compensation Plan	n/a		n/a	154,635
Equity compensation plans not approved by security holders	n/a		n/a	n/a
Total	454,023		n/a	4,700,612

(1) Represents unearned non-vested performance share awards from the 2015-2017, 2016-2018 and 2017-2019 performance periods, assuming a target level payout.

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: As permitted by Form 10-K General Instruction G(3), the information required by this Item will be incorporated by reference to SCANA's definitive proxy statement for the 2018 annual meeting of shareholders or included in an amendment to this Form 10-K to be filed not later than 120 days after December 31, 2017, which is the end of the fiscal year for SCANA.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA and SCE&G:

The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm's Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to the Company and Consolidated SCE&G for the fiscal years ended December 31, 2017 and 2016 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	The Company		Consolidated SCE&G	
	2017	2016	2017	2016
Audit Fees (1)	$ 3,670,360	$ 2,857,000	$ 3,127,191	$ 2,316,288
Audit-Related Fees (2)	168,229	171,710	139,172	117,146
Total Fees	$ 3,838,589	$ 3,028,710	$ 3,266,363	$ 2,433,434

(1) Fees for audit services billed in 2017 and 2016 consisted of audits of annual financial statements, comfort letters for securities underwriters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits and non-statutory audit services.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under Item 8 herein. The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under Item 8 herein. The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts

Description (in millions)		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2017	$ 6	$ 13	—	$ 13	$ 6
	2016	5	12	—	11	6
	2015	7	12	—	14	5
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2017	$ 9	$ 8	—	$ 8	$ 9
	2016	6	5	—	2	9
	2015	5	11	—	10	6
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2017	$ 3	$ 8	—	$ 7	$ 4
	2016	3	6	—	6	3
	2015	4	6	—	7	3
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2017	$ 8	$ 8	—	$ 8	$ 8
	2016	5	5	—	2	8
	2015	3	11	—	9	5

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ J. E. Addison
J. E. Addison, Chief Executive Officer and President

DATE: February 22, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ J. E. Addison
J. E. Addison, Chief Executive Officer and President
(Principal Executive Officer)

/s/ I. N. Griffin
I. N. Griffin, Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV
J. E. Swan, IV
Vice President and Controller
(Principal Accounting Officer)

Directors*:

G. E. Aliff	L. M. Miller
J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
S. A. Decker	A. Trujillo
D. M. Hagood	

* Signed on behalf of each of these persons by Jim Odell Stuckey, Attorney-in-Fact

DATE: February 22, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ J. E. Addison

J. E. Addison, Chief Executive Officer

DATE: February 22, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ J. E. Addison

J. E. Addison Chief Executive Officer
(Principal Executive Officer)

/s/ I. N. Griffin

I. N. Griffin
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Vice President and Controller
(Principal Accounting Officer)

Directors*:

G. E. Aliff	L. M. Miller
J. A. Bennett	J. W. Roquemore
J. F. A. V. Cecil	M. K. Sloan
S. A. Decker	A. Trujillo
D. M. Hagood	

* Signed on behalf of each of these persons by Jim Odell Stuckey, Attorney-in-Fact

DATE: February 22, 2018

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	Applicable to Form 10-K of SCE&G	Description
*2.01	X		Agreement and Plan of Merger by and among Dominion Energy, Sedona Corp., and SCANA, dated as of January 2, 2018 (Filed as Exhibit 2.1 to Form 8-K on January 5, 2018 (File No. 001-08809 (SCANA)) and incorporated by reference herein)
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-A to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of December 30, 2016 (Filed as Exhibit 3.05 to Form 10-K for the period ended December 31, 2016 (File No. 001-08809) and incorporated by reference herein)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.03		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.04		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.05		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
4.06		X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)
10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (Filed as Exhibit 10.01 to Amendment No. 2 of Form 10-Q/A for the quarter ended June 30, 2008 filed on May 25, 2017 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.03	X	X	Amendment to EPC Contract referred to in Exhibit 10.01 dated October 27, 2015 (Filed as Exhibit 10.05 to Form 10-Q for the quarter ended September 30, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
**10.04	X	X	SCANA Executive Deferred Compensation Plan (including amendments through November 25, 2014) (Filed as Exhibit 10.03 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
**10.05	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.06	X	X	SCANA Director Compensation and Deferral Plan (including amendments through August 25, 2016) (Filed herewith)
**10.07	X	X	SCANA Long-Term Equity Compensation Plan effective February 19, 2015 (Filed as Exhibit 4.05 to Registration Statement No. 333-204218 and incorporated by reference herein)
**10.08	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.09	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.10	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
**10.11	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein). (Filed on paper - hyperlink is not required pursuant to Rule 105 of Regulation S-T).
10.12		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.13	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.14	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
10.15	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A., as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.16	X	X	Amended and Restated Three-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.17	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.18	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
10.19	X	X	Settlement Agreement dated as of July 27, 2017, by and among Toshiba Corporation, SCE&G and Santee Cooper (Filed as Exhibit 99.2 to Form 8-K dated July 27, 2017 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.20	X	X	Trade Confirmation dated September 25, 2017, between SCE&G, Santee Cooper and Citibank, N.A., and associated Assignment and Purchase Agreement, dated September 27, 2017, by and among SCE&G, Santee Cooper and Citibank, N. A. (Filed as Exhibit 10.03 to Form 10-Q for the quarter ended September 30, 2017 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02		X	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS***	X	X	XBRL Instance Document
101. SCH***	X	X	XBRL Taxonomy Extension Schema
101. CAL***	X	X	XBRL Taxonomy Extension Calculation Linkbase
101. DEF***	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB***	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE***	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. SCANA agrees to furnish supplementally to the SEC a copy of any omitted schedule upon request by the SEC.

** Management Contract or Compensatory Plan or Arrangement

*** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

Exhibit 10.06

SCANA CORPORATION

DIRECTOR COMPENSATION AND DEFERRAL PLAN

(including amendments through August 25, 2016)

SCANA CORPORATION

DIRECTOR COMPENSATION AND DEFERRAL PLAN

TABLE OF CONTENTS

SCANA CORPORATION

DIRECTOR COMPENSATION AND DEFERRAL PLAN

SECTION 1. ESTABLISHMENT AND PURPOSE

1.1 Establishment of the Plan. SCANA Corporation (the "Company") established the SCANA Corporation Nonemployee Director Stock Plan, effective as of January 1, 1997. Effective as of January 1, 2001, the plan was renamed the "SCANA Corporation Director Compensation and Deferral Plan" (hereinafter called the "Plan") and amended and restated to include a deferred compensation component. Effective as of January 1, 2009, the Plan was amended and restated to comply with the requirements of Code Section 409A. Effective as of December 31, 2009, the Plan was again amended and restated to reflect further modifications to comply with Code Section 409A as well as to implement certain design changes. Effective as of April 21, 2011, and November 30, 2014, the Plan was again amended and restated. The Plan was most recently amended and restated as provided herein, effective as of August 25, 2016.

1.2 Purpose of the Plan. The purpose of the Plan is to promote the achievement of long-term objectives of the Company by linking the personal interests of Nonemployee Directors, as defined in Section 2(r) herein, to those of the Company's shareholders and to attract and retain Nonemployee Directors of outstanding competence by mandating that a certain portion as may be determined from time to time of the Retainer Fee of each Participant as defined in Section 2(u) herein, be paid in Company Stock, unless such amount is voluntarily deferred to a future date in accordance with the Plan's terms or pursuant to the SCANA Corporation Executive Deferred Compensation Plan ("EDCP"). The Plan is intended to conform to the provisions of Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any replacement rule in effect from time to time ("Rule 16b-3"). The Plan also provides a means by which Nonemployee Directors may defer certain additional amounts to some future period.

SECTION 2. DEFINITIONS

2.1 Definitions. Whenever used herein, the following terms shall have the meanings set forth below, unless otherwise expressly provided herein or unless a different meaning is plainly required by the context, and when the defined meaning is intended, the term is capitalized:

(a) "Act" means the Securities Exchange Act of 1934, as amended.

(b) "Beneficial Owner" shall have the meaning ascribed to such term in Rule 13d-3 of the General Rules and Regulations under the Act.

(c) "Beneficiary" means any person or entity who, upon the Participant's death, is entitled to receive the Participant's benefits under the Plan in accordance with Section 7 hereof.

(d) "Board of Directors" means the board of directors of the Company.

(e) "Change in Control" means a change in control of the Company of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Act, whether or not the Company is then subject to such reporting requirements; provided that, without limitation, such a Change in Control shall be deemed to have occurred if:

(i) Any Person (as defined in Section 3(a)(9) of the Act and used in Sections 13(d) and 14(d) thereof, including a "group" as defined in Section 13(d)) is or becomes the Beneficial Owner, directly or indirectly, of twenty-five percent (25%) or more of the combined voting power of the outstanding shares of capital stock of the Company;

(ii) During any period of two (2) consecutive years (not including any period prior to the execution of this Plan) there shall cease to be a majority of the Board of Directors comprised as follows: individuals who at the beginning of such period constitute the Board of Directors and any new director(s) whose election by the Board of Directors or nomination for election by the Company's stockholders was approved by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of the period or whose election or nomination for election was previously so approved; or

(iii) The consummation of a merger or consolidation of the Company with any other corporation, other than a merger or consolidation which would result in the voting shares of capital stock of the Company outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting shares of capital stock of the surviving entity) at least eighty percent (80%) of the combined voting power of the voting shares of capital stock of the Company or such surviving entity outstanding immediately after such merger or consolidation; or the shareholders of the Company approve a plan of complete liquidation of the Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets.

(f) "Code" means the Internal Revenue Code of 1986, as amended.

(g) "Company" means SCANA Corporation, a South Carolina corporation, or any successor thereto.

(h) "Company Stock" means the no par value common stock of the Company. In the event of a change in the capital structure of the Company (as provided in Section 3.6), the shares resulting from such a change shall be deemed to be Company Stock within the meaning of the Plan.

(i) "Company Stock Ledger" means an appropriate bookkeeping record established in the DCD Ledger for which amounts credited are converted into hypothetical credited shares of Company Stock.

(j) "Compensation" means Retainer Fees payable to a Participant during a Service Period by the Company.

(k) "DCD Ledger" means an appropriate bookkeeping record which shall be established for each Participant which shall reflect: (1) the amounts deferred on behalf of each Participant; and (2) the crediting of deemed investments (and hypothetical earnings on those deemed investments) with respect to amounts deferred on behalf of each Participant. Each DCD Ledger shall separately reflect the pre-2005 and post-2004 deferrals and hypothetical earnings thereon, and the portion of the post-2004 deferrals and hypothetical earnings thereon payable at a date certain and the portion payable when the Participant separates from service from the Board of Directors (referred to herein as a Participant's "pre-2005 DCD Ledger" and "post-2004 DCD Ledger"). A Participant's pre-2005 DCD Ledger shall reflect amounts deferred hereunder before January 1, 2005 (and the earnings credited thereon before, on or after January 1, 2005) for which (i) the Participant had a legally binding right as of December 31, 2004, to be paid the amount, and (ii) such right to the amount was earned and vested as of December 31, 2004 and was credited to the Participant's DCD Ledger hereunder. Pre-2005 DCD Ledgers are treated as "grandfathered" for the purposes of Code Section 409A, and are governed by the terms of the Plan in effect as of October 3, 2004.

(l) "Director" means an individual who is a member of the Board of Directors.

(m) "EDCP" means the SCANA Corporation Executive Deferred Compensation Plan.

(n) "Fair Market Value" of Company Stock shall mean:

(i) in the case of any distribution, the closing price for shares of Company Stock on the New York Stock Exchange on the date of distribution; and

(ii) in the case of any other transaction hereunder designed to track the investment or reinvestment of Company Stock, the closing price for shares of Company Stock on the New York Stock Exchange on the measuring date.

(o) "Growth Increment" means the amount of interest credited to amounts credited to a Participant's Growth Increment Ledger.

(p) "Growth Increment Ledger" means an appropriate bookkeeping record established in the DCD Ledger for which amounts are credited with Growth Increments.

(q) "Investor Plan" means the SCANA Investor Plus Plan.

(r) "Nonemployee Director" means a Director who is not currently employed by the Company or any subsidiary of the Company (without regard to whether such individual was previously employed by the Company).

(s) "Participant" means a Nonemployee Director satisfying the eligibility requirements of Section 3.

(t) "Plan" means the SCANA Corporation Director Compensation and Deferral Plan.

(u) "Retainer Fees" means the amount of compensation payable to each Participant with respect to services rendered to the Company as a Director for the Service Period. Such term includes annual leadership retainer fees payable to the Lead Director, Audit Committee Chair, Compensation Committee Chair, Nominating and Governance Committee Chair, Nuclear Oversight Committee Chair or any other retainer fee as determined by the Company or its delegate from time to time.

(v) "Rule 16b-3" means Rule 16b-3 of the Act, as amended, or any replacement rule in effect from time to time.

(w) "Service Period" means a calendar year.

2.2 Gender and Number. Except when otherwise indicated by the context, any masculine terminology used herein also shall include the feminine and the feminine shall include the masculine, and the use of any term herein in the singular may also include the plural and the plural shall include the singular.

SECTION 3. ELIGIBILITY AND PARTICIPATION

3.1 Eligibility. All Nonemployee Directors shall automatically be eligible to participate in this Plan.

3.2 Compensation Payment.

(a) Unless otherwise deferred in accordance with Section 4 or under the EDCP, each Participant's Retainer Fee amounts shall be paid to the Participant on a quarterly basis and such payment shall be made in shares of Company Stock or cash, as determined by the Company or its delegate. The portion of the Retainer Fee payment that is made in shares of Company Stock is referred to as the "Stock Retainer Fee" and the portion of the Retainer Fee payment that is made in cash is referred to as the "Cash Retainer Fee." Notwithstanding anything to the contrary in this Plan, if a Participant elects to defer all or a portion of his Retainer Fee under the EDCP and in accordance with the terms of the EDCP, the Company or its delegate shall designate a portion of the Retainer Fee as the "Stock Retainer Fee" and a portion of the Retainer Fee as the "Cash Retainer Fee," but no actual payment of shares of Company Stock shall be paid to such Participant and the terms of the EDCP will apply with respect to such deferred amounts.

(b) With respect to all payments in Company Stock under this Section 3.2, and subject to Sections 3.2(c) and 3.3, each Participant shall be entitled to a number of shares of Company Stock equal to the smallest number of whole shares of Company Stock which, when multiplied by Fair Market Value, would equal no less than the equivalent amount of Compensation otherwise payable to the Participant. Any remaining amounts representative of fractional shares of Company Stock owed shall be deposited into an account in the Participant's name in the Investor Plan.

(c) Notwithstanding anything in this Plan to the contrary, the maximum number of shares of Company Stock to which any Participant shall be entitled during a Service Period shall be 10,000, subject to the overall maximum amount in Section 3.4 and any adjustment provided in Section 3.6.

3.3 Payment of Company Stock. In connection with amounts to be paid during a Service Period under Section 3.2 which are paid in the form of Company Stock, each Participant may elect to have the shares of Company Stock to be issued to him pursuant to the Plan during the Service Period registered in his name. In such case, all shares of Company Stock to be paid shall be issued as promptly as practicable after the amounts are otherwise payable. If a Participant does not make such an election, all shares issued pursuant to the Plan during the Service Period will be deposited into an account in his name in the Investor Plan. All cash dividends paid on shares deposited in the Investor Plan will be reinvested in additional shares of Company Stock unless the Participant notifies the Investor Plan in accordance with the terms thereof that he does not want to reinvest such dividends. During the last quarter of each calendar year in which there is a change in the prospectus for the Investor Plan, all Participants who have not been provided previously with a copy of such changed prospectus shall be provided with a copy of the then-current prospectus. In addition, each Participant who is not yet a participant in the Investor Plan shall be given an Investor Plan prospectus shortly before he becomes an Investor Plan participant.

3.4 Stock. Company Stock issued pursuant to the Plan may be either original issue or stock purchased on the open market. The maximum number of shares that may be issued pursuant to the Plan is five hundred fifty thousand (550,000) shares, subject to adjustment as provided in Section 3.6. In the event of a change in the capital structure of the Company (as provided in Section 3.6), the shares resulting from such change shall be deemed to be Company Stock within the meaning of the Plan. The aggregate number of shares of Company Stock reserved for issuance pursuant to the Plan shall be reduced by the issuance of shares under the Plan.

3.5 Issuance of Company Stock. Notwithstanding anything in this Plan to the contrary:

(a) The Company shall not be required to issue or deliver any certificate for shares of Company Stock to a Participant before (i) such shares have been admitted to listing on the New York Stock Exchange, (ii) the Company has received any required registration or other qualification of such shares under any state or federal law or regulation that the Company's counsel shall determine is necessary or advisable and (iii) the Company is satisfied that all applicable legal requirements have been complied with. The Company may place on a certificate representing Company Stock any legend deemed necessary by the Company's counsel to comply with federal or state securities laws. Until the Participant has been issued a certificate for the shares of Company Stock acquired, the Participant shall possess no shareholder rights with respect to the shares.

(b) If at any time there may not be sufficient shares available under the Plan to permit the awards of Company Stock, the awards shall be reduced pro rata (to zero, if necessary) so as not to exceed the number of shares then available for issuance under the Plan.

3.6 Effect of Stock Dividends and Other Changes in Capital Structure. Appropriate adjustments shall be made automatically to the number and kind of shares to be issued under the Plan, as well as to any deferred amounts credited to a Participant's Company Stock Ledger and any other relevant provisions of the Plan, if there are any changes in the Company Stock by reason of a stock dividend, stock split, combination of shares, spin-off, reclassification, recapitalization, merger, consolidation or other change in the Company's capital stock (including, but not limited to, the creation or issuance to shareholders generally of rights, options, or warrants for the purchase of common stock or preferred stock of the Company). If the adjustment would produce fractional shares, the fractional shares shall be eliminated by rounding to the nearest whole share. Any adjustments shall be made in a manner consistent with Rule 16b-3. Any such adjustments shall neither enhance nor diminish the rights of a Participant and the Company shall pay all costs of administering the Plan, including all commissions with respect to open market purchases.

SECTION 4. ELECTION TO DEFER

4.1 Deferral Election. Subject to the conditions set forth in this Plan, and such procedures established by the Company, a Participant may elect to defer amounts of Compensation under this Plan, which amounts are not otherwise deferred by such Participant under the EDCP, as follows:

(a) At a time decided by the Company before the beginning of each Service Period, a Participant irrevocably may elect, by written notice to the Company's Secretary (or his designee), to defer a portion of his Compensation earned for such Service Period. In the case of a Participant elected to the Board of Directors during the Service Period, the Participant may elect, within 30 days of his election to the Board of Directors, to defer a portion of his Compensation for services to be performed subsequent to his election. Such election shall specify whether:

(i) the Participant elects to defer all or a portion of his Stock Retainer Fee and acknowledges that all such deferrals shall be credited to the Company Stock Ledger on his behalf; and

(ii) the Participant elects to defer all or a portion of his Cash Retainer Fee and designates what portions of all such deferrals shall be credited on his behalf to either the Growth Increment Ledger or the Company Stock Ledger;

provided, however, that once any portion of a Participant's Compensation is deferred and credited to the Company Stock Ledger as provided herein, that portion of Compensation may not subsequently be credited to the Growth Increment Ledger, and once any portion of a Participant's Compensation is deferred and credited to the Growth Increment Ledger as provided herein, that portion of Compensation may not subsequently be credited to the Company Stock Ledger.

(b) The deferral election specified in Section 4.1(a) above shall be applied to the Participant's Compensation for each Service Period (or the portion of the Service Period, as applicable) to which the deferral election applies. Any deferral election shall remain in effect for future Service Periods unless affirmatively changed in writing by the Participant and received by the Corporate Secretary by the time established for such purpose prior to the beginning of the Service Period for which the change is effective.

(c) If a Participant makes a deferral election under Section 4.1(a) whereby amounts are credited to the Company Stock Ledger on his behalf, dividends attributable to shares of Company Stock credited to his Company Stock Ledger shall be automatically deferred and deemed reinvested pursuant to Section 5.3.

4.2 Deferral Period. With respect to deferrals under this Plan made in accordance with Section 4.1, each Participant must elect a deferral period for each annual deferral. Subject to the additional deferral provisions of Section 4.3 and the acceleration provisions of Section 6.4, any post-2004 deferral may be until the earlier of (i) the Participant's separation from service from the Board of Directors for any reason or (ii) a date certain, subject to any limitations that the Company (or its delegate) in its discretion may choose to apply at the time of the deferral election. All post-2004 deferrals to a date certain must be to the same date certain. In the absence of an election to the contrary by the Participant for amounts deferred hereunder for any deferral period, such deferrals shall be paid in a lump sum payment as soon as practicable after the Participant's separation from service from the Board of Directors for any reason.

4.3 Election to Defer a Previously Deferred Amount or Change the Manner of Payment.

(a) Subject to the acceleration provisions of Section 6.4 and the Board of Directors approval requirement of Section 4.3(b) with respect to pre-2005 deferrals, a Participant may elect an additional deferral period of at least sixty (60) months with respect to any previously deferred amount credited to the post-2004 DCD Ledger that is payable at a date certain, and an additional deferral period of at least twelve (12) months for each separate deferral credited to the pre-2005 DCD Ledger. With respect to amounts deferred until separation from service from the Board of Directors, Participants may also elect a new manner of payment permitted under Section 6.2 with respect to any previously deferred amounts, provided that in the case of amounts credited to post-2004 DCD Ledgers that are payable on separation from service from the Board of Directors, payments are delayed for sixty (60) months from the date payments would otherwise have commenced absent the election. Any such election must be made by written notice to the Company (or its delegate) at least twelve (12) months before the expiration of the deferral period for any previously deferred amount with respect to which an additional deferral election is made (the "Modification Period").

(b) A new deferral period election or a new form of payment election made pursuant to Subsection 4.3(a) above with respect to pre-2005 DCD Ledgers shall not be automatically binding upon the Company by the mere fact of the election request(s) having been made. The Board of Directors (or its delegate) shall review each such election submitted and determine whether or not it is in the best interest of the Company to accept the elections as submitted. Such Board of Directors (or delegate) review will be made on a case-by-case basis and all determinations shall be made by the Board of Directors (or its delegate) in its sole and complete discretion after consideration of such factors as it deems relevant, including broad economic and policy implications to the Company of approving any request. The Board of Directors, or its delegate, shall notify each Participant in writing within the first sixty (60) days of the Modification Period as to whether the deferral period election or manner of payment election with respect to pre-2005 DCD Ledgers are accepted by the Company as submitted, and if not, the terms upon which such election(s) would be accepted; in the latter instance, the Participant shall, no later than on the seventy-fifth (75th) day of the Modification Period, inform the Board of Directors (or its delegate) in writing of his acceptance or rejection of the terms proffered by the Company (or its delegate). All determinations made by the Board of Directors or its delegate shall be final and binding on all parties.

4.4 Election to Change the Deferral Period and/or Form of Payment for Post-2004 DCD Ledgers.

Notwithstanding Section 4.3(a), a Participant may elect at any time prior to January 1, 2009 to change the deferral period (accelerate or defer) and/or method of payment with respect to any post-2004 DCD Ledger that is not scheduled for payment in 2008 by making written notice to the Board of Directors (or its delegates), provided such change does not cause any amounts to be paid in 2008 or cause any amounts otherwise payable in 2008 to be deferred to a later year. Any new deferral period and/or method of payment shall be subject to the requirements of Section 6.

SECTION 5. CREDITING AND INVESTMENT OF DEFERRALS

5.1 DCD Ledger. The Company shall establish for each Participant a DCD Ledger which shall reflect the amounts deferred on behalf of each Participant. In the sole discretion of the Company, one or more appropriate bookkeeping records shall be established in the DCD Ledger to reflect the deemed investments (and hypothetical earnings) made by each Participant in accordance with this Section 5 which shall include, but not be limited to, the Company Stock Ledger and the Growth Increment Ledger. Each DCD Ledger shall separately reflect the pre-2005 and post-2004 deferrals and hypothetical earnings thereon, and the portion of the post-2004 deferrals and hypothetical earnings thereon payable at a date certain and the portion payable when the Participant separates from service from the Board of Directors.

5.2 Adjustment of Amounts Credited to Growth Increment Ledger. All deferrals credited to each Participant's Growth Increment Ledger will be credited with Growth Increments based on the prime interest rate charged from time to time by the Wachovia Bank, N.A. The Company will have the authority to change the interest rate that may be applied to the Growth Increment Ledger. The Participant's Growth Increment Ledger shall be credited on the first day of each calendar quarter, with a Growth Increment computed on the average balance in the Participant's Growth Increment Ledger during the preceding calendar quarter. The Growth Increment shall be equal to the amount in said Growth Increment Ledger multiplied by the average interest rate selected by the Company during the preceding calendar quarter times a fraction the numerator of which is the number of days during such quarter and the denominator of which is three hundred sixty five (365). Growth Increments will continue to be credited until all of a Participant's benefits have been paid out of the Plan.

5.3 Adjustment of Amounts Credited to Company Stock Ledger. All deferrals credited to each Participant's Company Stock Ledger will be converted into hypothetical credited shares of Company Stock based on the Fair Market Value of the Company Stock on the date the deferrals would otherwise have been paid to the Participant. The value of each Participant's Company Stock Ledger shall be adjusted from time to time to reflect increases and decreases in shares of Company Stock as well as any stock or cash dividends, stock splits, or other changes in the capital structure of the Company (as provided in Section 3.6), that may from time to time be declared. All dividends attributable to hypothetical shares of Company Stock credited to each Participant's Company Stock Ledger shall be converted to additional credited shares of Company Stock as though reinvested as of the next business day after the dividend is paid.

5.4 Deemed Investments Not Actual Investments. Nothing in this Plan shall be construed to require the investment of any deferrals in shares of Company Stock or any other investment or give a Participant any rights whatsoever with respect to any shares of Company Stock or with respect to any other investment.

5.5 Charges Against DCD Ledger. There shall be charged against each Participant's DCD Ledger any payments made to the Participant or to his Beneficiary in accordance with Section 6 hereof.

SECTION 6. PAYMENT OF DEFERRED AMOUNTS

6.1 Payment of Deferred Amounts. The aggregate amounts payable under Section 6.2 as charges against the Participant's amount credited in the DCD Ledger shall be paid commencing with the conclusion of the deferral period selected by the Participant pursuant to Section 4.2, Section 4.3, or Section 4.4 hereof. The payments shall be made in the manner selected by the Participant under Section 6.2 of this Plan.

6.2 Manner of Payment. Amounts credited to post-2004 DCD Ledgers that are scheduled to be paid at a "date certain" payment shall be made only in the form of a single sum payment as soon as practicable after the date certain. With respect to amounts credited to pre-2005 DCD Ledgers, and amounts credited to post-2004 DCD Ledgers that are scheduled to be paid on separation from service from the Board of Directors, Participants must irrevocably elect (subject to permitted changes under Section 4.3 and the acceleration provisions of Section 6.4) to have payment made in accordance with one of the following distribution forms:

(i) a single sum payment;

(ii) a designated number of installments payable monthly, quarterly or annually, as elected (and in the absence of an election, annually), payable over a specified period not in excess of twenty (20) years; or

(iii) in the case of a post-2004 DCD Ledger, payments in the form of annual installments with the first installment being a single sum payment of ten percent (10%) of the post-2004 DCD Ledger determined immediately prior to the date such payment is made with the balance of the post-2004 DCD Ledger paid in annual installments determined in accordance with Section 6.3 over a total specified period not in excess of twenty (20) years,

which shall be paid or commence to be paid as soon as practicable after the conclusion of the deferral period elected pursuant to Section 4.2 or Section 4.3. Any such election shall be made at the same time as the election made pursuant Section 4.1. Unless otherwise specifically elected, payments of all deferred amounts will be made in a single sum payment made as soon as practicable after the conclusion of the deferral period elected pursuant to Section 4.2 or Section 4.3. If a Participant elects an installment form of payment but fails to specify between the installment form under Section 6.2(ii) or the installment form under Section 6.2(iii), the Participant's benefit will be paid in the installment form under Section 6.2(ii).

6.3 Form of Payment. Amounts credited to a Participant's Growth Increment Ledger and Company Stock Ledger shall be paid as follows:

(a) Amounts credited to the Participant's Growth Increment Ledger shall be paid in cash. If a Participant's benefit hereunder is to be paid in installments, the amount of each payment shall be equal to the amount credited to the Participant's Growth Increment Ledger at the time of payment multiplied by a fraction, the numerator of which is one and the denominator of which is the number of installment payments remaining.

(b) Amounts credited to the Participant's Company Stock Ledger shall be paid in shares of Company Stock with any amount representing a partial share of Company Stock deposited into an account in the Participant's name in the Investor Plan. A payment of an amount credited to the Participant's Company Stock Ledger shall be converted into actual shares of Company Stock as soon as practicable prior to each payment being made to the Participant. If a Participant's benefit hereunder is to be paid in installments, the amount of each payment shall be equal to the number of shares of Company Stock then credited to the Participant's Company Stock Ledger multiplied by a fraction, the numerator of which is one and the denominator of which is the number of installment payments remaining. Any amounts attributable to a partial share of Company Stock as of any installment payment date shall be deposited into an account in the Participant's name in the Investor Plan with each installment.

6.4 Acceleration of Payments. Notwithstanding the election made pursuant to Section 4.2, Section 4.3, or Section 4.4,

(a) payments shall be paid, or begin to be paid, as soon as practicable following the Participant's separation from service from the Board of Directors for any reason except as otherwise provided herein;

(b) if a Participant dies prior to the payment of all or a portion of the amounts credited to his DCD Ledger, the balance of any amount payable shall be paid in a cash lump sum to the Beneficiaries designated under Section 7 hereof;

(c) if a Participant ceases to be a Nonemployee Director but thereafter becomes an employee of the Company (or any of its subsidiaries or affiliates), all pre-2005 DCD Ledgers shall be paid as soon as practicable after such individual becomes an employee of the Company (or any of its subsidiaries or affiliates) in a single sum payment and all post-2004 DCD Ledgers shall be paid as soon as practicable after such individual has incurred a separation from service as a Nonemployee Director (as determined in accordance with Code Section 409A);

(d) if a Participant's post-2004 DCD Ledger balance is less than one hundred thousand dollars ($100,000) (five thousand dollars ($5,000) for pre-2005 DCD Ledgers) at the time for payment specified, such amount shall be paid in a single sum payment; and

(e) if applicable, the provisions of Section 8 shall apply.

Notwithstanding Section 6.4(a), in the case of any post-2004 DCD Ledgers that are payable on separation from service from the Board of Directors and that are subject to an additional deferral period of sixty (60) months under Section 4.3(a) as a result of the modification of the manner of payment, no payment attributable to any post-2004 DCD

Ledgers shall be accelerated under Section 6.4(a) to a date earlier than the expiration of the sixty (60) month period.

6.5 Financial Emergency. The Company (or its delegate), at its sole discretion, may alter the timing or manner of payment of deferred amounts if the Participant establishes, to the satisfaction of the Company (or its delegate), an unanticipated and severe financial hardship that is caused by an event beyond the Participant's control. In such event, the Company (or its delegate) may:

(a) provide that all, or a portion of, the amount previously deferred by the Participant immediately shall be paid in a lump sum cash payment,

(b) provide that all, or a portion of, the installments payable over a period of time immediately shall be paid in a lump sum cash payment, or

(c) provide for such other installment payment schedules as it deems appropriate under the circumstances,

as long as the amount distributed shall not be in excess of that amount which is necessary for the Participant to satisfy the financial emergency. For pre-2005 DCD Ledgers, severe financial hardship will be deemed to have occurred in the event of the Participant's or a dependent's sudden, lengthy and serious illness as to which considerable medical expenses are not covered by insurance or relative to which there results a significant loss of family income, or other unanticipated events of similar magnitude. For post-2004 DCD Ledgers, severe financial hardship will be deemed to have occurred from a sudden or unexpected illness or accident of the Participant or the Participant's spouse, Beneficiary or dependent (as defined in Code Section 152, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)), loss of the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the Participant's control. Examples of events that may constitute an unforeseeable emergency for post-2004 DCD Ledgers include the imminent foreclosure of or eviction from the Participant's primary residence; the need to pay for medical expenses, including non-refundable deductibles, as well as for the costs of prescription drug medication; and the need to pay for the funeral expenses of the Participant's spouse, Beneficiary or dependent (as defined in Code Section 152, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)). The circumstances that will constitute an unforeseeable emergency will depend upon the facts of each case, but, in any case, payment may not be made to the extent that such hardship is or may be relieved through reimbursement or compensation by insurance or otherwise, by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship, or by cessation of deferrals under the Plan. Examples of circumstances that are not considered to be unforeseeable emergencies include the need to send a Participant's child to college or the desire to purchase a home. The Company's decision (or that of its delegate) in passing on the severe financial hardship of the Participant and the manner in which, if at all, the payment of deferred amounts shall be altered or modified shall be final, conclusive, and not subject to appeal. The Company shall consider any requests for payment under this Section 6.5 in accordance with the standards of interpretation described in Code Section 409A and the regulations and other guidance thereunder.

6.6 Compliance with Domestic Relations Order . Notwithstanding anything to the contrary in this Plan, a distribution shall be made from the Participant's DCD Ledgers to an individual other than the Participant to the extent necessary to comply with a domestic relations order (as defined in Code Section 414(p)(1)(B)).

SECTION 7. BENEFICIARY DESIGNATION

7.1 Designation of Beneficiary. A Participant shall designate a Beneficiary or Beneficiaries who, upon the Participant's death, are to receive the amounts that otherwise would have been paid to the Participant. All designations shall be in writing and signed by the Participant. The designation shall be effective only if and when delivered to the Company during the lifetime of the Participant. The Participant also may change his Beneficiary or Beneficiaries by a signed, written instrument delivered to the Company. The payment of amounts shall be in accordance with the last unrevoked written designation of Beneficiary that has been signed and delivered to the Company. All Beneficiary designations shall be addressed to the Company's Secretary and delivered to his office.

7.2 Death of Beneficiary.

(a) In the event that all of the Beneficiaries named pursuant to Section 7.1 predecease the Participant, the amounts that otherwise would have been paid to said Beneficiaries shall, where the designation fails to redirect to alternate Beneficiaries in such circumstance, be paid to the Participant's estate as the alternate Beneficiary.

(b) In the event that two or more Beneficiaries are named, and one or more but less than all of such Beneficiaries predecease the Participant, each surviving Beneficiary shall receive any proportion or amount of funds designated or indicated for him per the designation under Section 7.1, and the indicated share of each predeceased Beneficiary which the designation fails to redirect to an alternate Beneficiary in such circumstance shall be paid to the Participant's estate as an alternate Beneficiary.

7.3 Ineffective Designation.

(a) In the event the Participant does not designate a Beneficiary, or if for any reason such designation is entirely ineffective, the amounts that otherwise would have been paid to the Beneficiary shall be paid to the Participant's estate as the alternate Beneficiary.

(b) In the circumstance that designations are effective in part and ineffective in part, to the extent that a designation is effective, distribution shall be made so as to carry out as closely as discernable the intent of the Participant, with the result that only to the extent that a designation is ineffective shall distribution instead be made to the Participant's estate as an alternate Beneficiary.

SECTION 8. CHANGE IN CONTROL PROVISIONS

8.1 Successors. Notwithstanding anything in this Plan to the contrary, upon the occurrence of a Change in Control, the Company will require any successor (whether direct or indirect, by purchase, merger, consolidation, or otherwise) of all or substantially all of the business and/or assets of the Company or of any division or subsidiary thereof to expressly assume and agree to perform this Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place, subject to the remaining provisions of this Section 8.1. Participants shall become entitled to benefits hereunder in accordance with the terms of this Plan, based on amounts credited to each Participant's DCD Ledger as of the date of such Change in Control plus accumulated Growth Increments attributable thereto (adjusted to reflect any change from the most recent Growth Increment calculation to the end of the month prior to the month such amounts are distributed to each Participant). In such case, any successor to the Company shall not be required to provide for additional deferral of benefits beyond the date of such Change in Control except as required under Code Section 409A.

8.2 Amendment and Termination After Change in Control. Notwithstanding the foregoing, and subject to this Section 8, no amendment, modification or termination of the Plan may be made, and no Participants may be added to the Plan, upon or following a Change in Control if it would have the effect of reducing any benefits earned (including optional forms of distribution) prior to such Change in Control without the written consent of all of the Plan's Participants covered by the Plan at such time. In all events, however, the Company reserves the right to amend, modify or delete the provisions of Section 8 at any time prior to a Change in Control, pursuant to a Board of Directors resolution adopted by a vote of two-thirds (2/3) of the Board of Directors members then serving on the Board of Directors.

SECTION 9. GENERAL PROVISIONS

9.1 Contractual Obligation. It is intended that the Company is under a contractual obligation to make payments from a Participant's DCD Ledger when due. Payment of amounts credited to a Participant's DCD Ledger shall be made out of the general funds of the Company as determined by the Board of Directors without any restriction of the assets of the Company relative to the payment of such contractual obligations; the Plan is, and shall operate as, an unfunded plan.

9.2 Unsecured Interest. No Participant or Beneficiary shall have any interest whatsoever in any specific asset of the Company. To the extent that any person acquires a right to receive payment under this Plan, such right shall be no greater than the right of any unsecured general creditor of the Company.

9.3 "Rabbi" Trust. In connection with this Plan, the Company shall establish a grantor trust (known as the "SCANA Corporation Director Compensation Trust" and referred to herein as the "Trust") for the purpose of accumulating funds to satisfy the obligations incurred by the Company under this Plan (and such other plans and arrangements as determined from time to time by the Company). At any time prior to a Change in Control, as that term is defined in such Trust, the Company may transfer assets to the Trust to satisfy all or part of the obligations incurred by the Company under this Plan, as determined in the sole discretion of the Board of Directors, subject to the return of such assets to the Company at such time as determined in accordance with the terms of such Trust. Any assets of such Trust shall remain at all times subject to the claims of creditors of the Company in the event of the Company's insolvency; and no asset or other funding medium used to pay benefits accrued under the Plan shall result in the Plan being considered as other than "unfunded" under ERISA. Notwithstanding the establishment of the Trust, the right of any Participant to receive future payments under the Plan shall remain an unsecured claim against the general assets of the Company.

9.4 Nonalienation of Benefits.

(a) Subject to Section 6.6, no right or benefit under this Plan shall be subject to anticipation, alienation, sale, assignment, pledge, encumbrance, or charge, and any attempt to anticipate, alienate, sell, assign, pledge, encumber or charge the same shall be void; nor shall any such disposition be compelled by operation of law.

(b) No right or benefit hereunder shall in any manner be liable for or subject to the debts, contracts, liabilities, or torts of the person entitled to benefits under the Plan.

(c) If any Participant or Beneficiary hereunder should become bankrupt or attempt to anticipate, alienate, sell, assign, pledge, encumber, or charge any right or benefit hereunder (other than as permitted in Section 6.6), then such right or benefit shall, in the discretion of the Board of Directors, cease, and the Board of Directors shall direct in such event that the Company hold or apply the same or any part thereof for the benefit of the Participant or Beneficiary in such manner and in such proportion as the Board of Directors may deem proper.

9.5 Severability. If any particular provision of the Plan shall be found to be illegal or unenforceable for any reason, the illegality or lack of enforceability of such provision shall not affect the remaining provisions of the Plan, and the Plan shall be construed and enforced as if the illegal or unenforceable provision had not been included.

9.6 No Individual Liability. It is declared to be the express purpose and intention of the Plan that no liability whatsoever shall attach to or be incurred by the shareholders, officers, or directors of the Company or any representative appointed hereunder by the Company, under or by reason of any of the terms or conditions of the Plan.

9.7 Applicable Law. This Plan shall be governed and construed in accordance with the laws of the State of South Carolina except to the extent governed by applicable Federal law (including the requirements of Code Section 409A). The terms of this Plan are also subject to all present and future rulings of the Securities and Exchange Commission with respect to Rule 16b-3. If any provision of the Plan would cause the Plan to fail to meet the requirements of Rule 16b-3, then that provision of the Plan shall be void and of no effect.

SECTION 10. PLAN ADMINISTRATION, AMENDMENT AND TERMINATION

10.1 In General. This Plan shall be administered by the Company, which shall have the sole authority to construe and interpret the terms and provisions of the Plan and determine the amount, manner and time of payment of any benefits hereunder. The Company shall not exercise any discretion with respect to the administration of this Plan, except as may be permitted by Rule 16b-3. The Company shall maintain records, make the requisite calculations and disburse payments hereunder, and its interpretations, determinations, regulations and calculations shall be final and binding on all persons and parties concerned. The Company may adopt such rules as it deems necessary, desirable or appropriate in administering this Plan.

10.2 Claims Procedure. Any person dissatisfied with the Company's determination of a claim for benefits hereunder must file a written request for reconsideration with the Company (or its delegate). This request must include a written explanation setting forth the specific reasons for such reconsideration. The Company shall review its determination promptly and render a written decision with respect to the claim, setting forth the specific reasons for such denial written in a manner calculated to be understood by the claimant. Such claimant shall be given a reasonable time within which to comment, in writing, to the Company with respect to such explanation. The Company shall review its determination promptly and render a written decision with respect to the claim. Such decision upon matters within the scope of the authority of the Company shall be conclusive, binding, and final upon all claimants under this Plan.

10.3 Finality of Determination. The determination of the Company as to any disputed questions arising under this Plan, including questions of construction and interpretation, shall be final, binding, and conclusive upon all persons.

10.4 Delegation of Authority. The Company may, in its discretion, delegate its duties to a committee of the Board of Directors or an officer or other employee of the Company, or to a committee composed of officers or employees of the Company.

10.5 Expenses. The cost of payment from this Plan and the expenses of administering the Plan shall be borne by the Company.

10.6 Tax Withholding. The Company shall have the right to deduct from all payments made from the Plan any federal, state, or local taxes required by law to be withheld with respect to such payments.

10.7 Incompetency. Any person receiving or claiming benefits under the Plan shall be conclusively presumed to be mentally competent and of age until the Company receives written notice, in a form and manner acceptable to it, that such person is incompetent or a minor, and that a guardian, conservator, statutory committee under the South Carolina Code of Laws, or other person legally vested with the care of his estate has been appointed. In the event that the Company finds that any person to whom a benefit is payable under the Plan is unable to properly care for his affairs, or is a minor, then any payment due (unless a prior claim therefor shall have been made by a duly appointed legal representative) may be paid to the spouse, a child, a parent, or a brother or sister, or to any person deemed by the Company to have incurred expense for the care of such person otherwise entitled to payment.

In the event a guardian or conservator or statutory committee of the estate of any person receiving or claiming benefits under the Plan shall be appointed by a court of competent jurisdiction, payments shall be made to such guardian or conservator or statutory committee provided that proper proof of appointment is furnished in a form and manner suitable to the Company. Any payment made under the provisions of this Section 10.7 shall be a complete discharge of liability therefor under the Plan.

10.8 Action by Company. Any action required or permitted to be taken hereunder by the Company or its Board of Directors shall be taken by the Board of Directors, or by any person or persons authorized by the Board of Directors.

10.9 Notice of Address. Any payment made to a Participant or to his Beneficiary at the last known post office address of the distributee on file with the Company, shall constitute a complete acquittance and discharge to the Company and any director or officer with respect thereto, unless the Company shall have received prior written notice of any change in the condition or status of the distributee. Neither the Company nor any director or officer shall have any duty or obligation to search for or ascertain the whereabouts of the Participant or his Beneficiary.

10.10 Amendment and Termination. The Company expects the Plan to be permanent but, since future conditions affecting the Company cannot be anticipated or foreseen, the Company reserves the right to amend, modify, or terminate the Plan at any time by action of its Board of Directors, subject to Section 8.2 and the requirements of Code Section 409A with respect to post-DCD Ledgers, (including, but not limited to, as may be necessary to ensure compliance with Rule 16b-3); provided, however, that any such action shall not diminish retroactively any amounts which have been credited to any Participant's DCD Ledger. If the Board of Directors amends the Plan to cease future deferrals hereunder or terminates the Plan, the Board of Directors may, in its sole discretion, direct that the value of each Participant's DCD Ledger be paid to each Participant (or Beneficiary, if applicable) in an immediate lump sum payment. In the absence of any such direction from the Board of Directors, the Plan shall continue as a "frozen" plan under which no future deferrals will be recognized (however, Growth Increments and dividends attributable to hypothetical shares of Company Stock credited to each Participant's Company Stock Ledger shall continue to be recognized) and each Participant's benefits shall be paid in accordance with the otherwise applicable terms of the Plan.

10.11 Plan to Comply with Code Section 409A. Notwithstanding any provision to the contrary in this Plan, each provision of this Plan shall be interpreted to permit Director deferrals and the payment of deferred amounts in accordance with Code Section 409A and any provision that would conflict with such requirements shall not be valid or enforceable.

SECTION 11. EXECUTION

IN WITNESS WHEREOF, the Company has caused this SCANA Corporation Director Compensation and Deferral Plan to be executed by its duly authorized officer to be effective on the 25th day of August, 2016.

SCANA Corporation

By: /s/ M. K. Phalen
Title: Senior Vice President, Administration

ATTEST:
/s/ G. Champion
Vice President, Corporate Secretary

Exhibit 12.01

COMPUTATION OF RATIOS
December 31, 2017

BOND RATIO

SCANA and SCE&G:

Dollars in Millions Year Ended December 31, 2017			
Net earnings as defined in SCE&G's bond indenture dated April 1, 1993 (Mortgage)		$ 1,342.7	*
Divide by annualized interest charges on:			
Bonds outstanding under the Mortgage	$ 256.4		
Total annualized interest charges	256.4		
Bond Ratio		5.24	

* Net earnings as defined excludes the recognition of expense due to the nonrecoverability of investment; therefore, it excludes the impairment loss.

RATIO OF EARNINGS TO FIXED CHARGES

Dollars in Millions	SCANA					SCE&G				
Years Ended December 31,	2017	2016	2015	2014	2013	2017	2016	2015	2014	2013
Fixed Charges as defined:										
Interest on debt	$377.6	$356.8	$327.8	$318.2	$305.9	$300.2	$284.6	$258.4	$237.6	$226.4
Amortization of debt premium, discount and expense (net)	4.0	4.5	4.7	9.7	5.3	2.9	3.5	3.7	4.4	4.2
Interest component on rentals	3.3	3.5	3.7	4.1	4.9	3.8	4.0	4.1	4.0	4.5
Total Fixed Charges (A)	$384.9	$364.8	$336.2	$332.0	$316.1	$306.9	$292.1	$266.2	$246.0	$235.1
Earnings as defined:										
Pretax income (loss) from continuing operations	($230.7)	$865.6	$1,138.4	$786.0	$693.8	($342.6)	$774.1	$711.0	$676.0	$579.7
Total fixed charges above	384.9	364.8	336.2	332.0	316.1	306.9	292.1	266.2	246.0	235.1
Pretax equity in (earnings) losses of investees	8.9	(0.7)	0.8	(1.4)	(3.2)	4.6	3.1	5.0	5.3	3.5
Cash distributions from equity investees	2.7	3.7	4.0	7.4	9.6	-	-	-	-	-
Total Earnings (Loss) (B)	$165.8	$1,233.4	$1,479.4	$1,124.0	$1,016.3	($31.1)	$1,069.3	$982.2	$927.3	$818.3
Ratio of Earnings (Loss) to Fixed Charges (B/A)	0.43	3.38	4.40	3.39	3.22	(0.10)	3.66	3.69	3.77	3.48
Amount of Earnings Deficiency Below Fixed Charges	$219.1					$338.0				

Exhibit 21.01

Each of the following subsidiaries of SCANA is incorporated in the state of South Carolina, except as otherwise indicated.

South Carolina Electric & Gas Company
South Carolina Generating Company, Inc.
South Carolina Fuel Company, Inc.
Public Service Company of North Carolina, Incorporated
SCANA Energy Marketing, Inc.
SCANA Services, Inc.
SCANA Communications Holdings, Inc., incorporated in the State of Delaware
SCANA Corporate Security Services, Inc.

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-191691, 333-204218 and 333-213797 on Form S-8 and Registration Statement Nos. 333-206629 and 333-213798 on Form S-3 of our reports dated February 22, 2018, relating to the consolidated financial statements and financial statement schedule of SCANA Corporation and subsidiaries (the “Company”) (which report expresses an unqualified opinion and includes an emphasis-of-matter paragraph regarding legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company as a result of the abandoned Nuclear Project), and the effectiveness of the Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2017.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-206629-01 on Form S-3 of our report dated February 22, 2018, relating to the consolidated financial statements and financial statement schedule of South Carolina Electric & Gas Company and affiliates (which report expresses an unqualified opinion and includes an emphasis-of-matter paragraph regarding legal, legislative, and regulatory matters that may result in material impacts to results and the liquidity of the Company as a result of the abandoned Nuclear Project), appearing in this Annual Report on Form 10-K of South Carolina Electric & Gas Company for the year ended December 31, 2017.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 22, 2018

Exhibit 24.01

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of SCANA Corporation (“SCANA”), hereby constitutes and appoints Jimmy E. Addison, Iris N. Griffin and Jim Odell Stuckey, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCANA’s fiscal year ended December 31, 2017, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the “Annual Report”), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 22nd day of February 2018.

/s/G. E. Aliff
G. E. Aliff
Director

/s/J. A. Bennett
J. A. Bennett
Director

/s/J. F. A. V. Cecil
J. F. A. V. Cecil
Director

/s/S. A. Decker
S. A. Decker
Director

/s/D. M. Hagood
D. M. Hagood
Director

/s/L. M. Miller
L. M. Miller
Director

/s/J. W. Roquemore
J. W. Roquemore
Director

/s/M. K. Sloan
M. K. Sloan
Director

/s/A. Trujillo
A. Trujillo
Director

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of South Carolina Electric & Gas Company ("SCE&G"), hereby constitutes and appoints Jimmy E. Addison, Iris N. Griffin and Jim Odell Stuckey, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCE&G's fiscal year ended December 31, 2017, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 22nd day of February 2018.

/s/G. E. Aliff
G. E. Aliff
Director

/s/J. A. Bennett
J. A. Bennett
Director

/s/J. F. A. V. Cecil
J. F. A. V. Cecil
Director

/s/S. A. Decker
S. A. Decker
Director

/s/D. M. Hagood
D. M. Hagood
Director

/s/L. M. Miller
L. M. Miller
Director

/s/J. W. Roquemore
J. W. Roquemore
Director

/s/M. K. Sloan
M. K. Sloan
Director

/s/A. Trujillo
A. Trujillo
Director

Exhibit 31.01

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 22, 2018	/s/Jimmy E. Addison
	Jimmy E. Addison, Chief Executive Officer and President

Exhibit 31.02

CERTIFICATION

I, Iris N. Griffin, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

February 22, 2018

/s/Iris N. Griffin

Iris N. Griffin

Senior Vice President and Chief Financial Officer

Exhibit 31.03

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 22, 2018

/s/Jimmy E. Addison

Jimmy E. Addison
Chief Executive Officer

Exhibit 31.04

CERTIFICATION

I, Iris N. Griffin, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 22, 2018

/s/Iris N. Griffin

Iris N. Griffin
Senior Vice President and Chief Financial Officer

Exhibit 32.01

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the “Company”) on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 22, 2018

/s/Jimmy E. Addison	/s/Iris N. Griffin
Jimmy E. Addison	Iris N. Griffin
Chief Executive Officer and President	Senior Vice President and Chief Financial Officer

Exhibit 32.02

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of South Carolina Electric & Gas Company (the “Company”) on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 22, 2018

/s/Jimmy E. Addison	/s/Iris N. Griffin
Jimmy E. Addison	Iris N. Griffin
Chief Executive Officer	Senior Vice President and Chief Financial Officer

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (2nd Continuing AIR)
DOCKET NO. 2017-305-E (1st Continuing AIR)
DOCKET NO. 2017-370-E (1st Continuing AIR)

Request 1-111:

In working Excel documents with all formulas intact, please provide the impacts of the one-time rate credit for:

a. A typical Residential customer (Rate 8, 1,000 kWh per month);
b. A typical Commercial customer (Rate 20, 150,000 kWh and 500 kVa per month);
c. A typical Industrial customer (Rate 23, 10,000 kW and 90% load factor per month);

Response No. 1-111:

RATE CREDIT COMPARISON

	SERVICE	MONTHLY KWH	YEARLY KWH	CREDIT FACTOR	TOTAL CREDIT
a.	Rate 8 - Residential	1,000	12,000	$ 0.07837	**$ 940.44**
b.	Rate 20 - Medium General Service	150,000	1,800,000	$ 0.05828	**$ 104,904.00**
c.	Rate 23 - Large General Service	6,570,000	78,840,000	$ 0.04188	**$ 3,301,819.20**

AVERAGE CUSTOMER RATE CREDIT COMPARISON BY CLASS

SERVICE	MONTHLY KWH	YEARLY KWH	CREDIT FACTOR	TOTAL CREDIT
Residential	1,102	13,224	$ 0.07837	**$ 1,036.36**
Small General Service	3,036	36,432	$ 0.06745	**$ 2,457.34**
Medium General Service	69,877	838,524	$ 0.05828	**$ 48,869.18**
Large General Service	1,918,326	23,019,912	$ 0.04188	**$ 964,073.91**

Note: Rate credit factor was developed using 2016 usage and demand allocation data.

Customer Benefits Plan Overview
ORS set 1 responses

Response Number	Response
Response 116:	Please see linked formula for a schedule and calculation of the customer refund amount ($M)
Response 118:	Please see linked formula for a schedule of the regulatory liability and the annual refund amount tl
Response 134:	Please see linked formula for a schedule and calculation of the estimated DTA associated with the
Response 134:	Please see linked formula for a schedule and calculation of the DTL associated with the customer b
Response 135:	Please see linked formula for the nominal rate payer total cost under the Customer Benefits Plan (
Response 136:	Please see the linked formula for the impacts for each year over 20 years on a typical residential cu
Response 136:	Please see the linked formula for the impacts for each year over 20 years on a typical commercial
Response 136:	Please see the linked formula for the impacts for each year over 20 years on a typical industrial cus
Response 140:	Please see linked formula for the total return in nominal dollars for the revenue requirement of an
Response 140:	Please see linked formula for the total return in discounted dollars for the revenue requirement of
Response 140:	Please see linked formula for the total return in nominal dollars of the revenue requirement over a
Response 140:	Please see linked formula for the total return in discounted dollars of the revenue requirement ove
Response 143:	Please see the tab labeled SCE&G PF BS for the response to request 143
Response 143:	Please see the tab labeled SCE&G PF IS for the response to request 143

Link	Notes
$575	
$575	
$763	
$1,273	
$5,097	*$4,034 nominal rate pay*
(3.5%)	
(3.3%)	
(3.9%)	
$14,376	*$16,116 nominal rate pa*
$3,611	
$5,097	
$2,349	
SCE&G Pro Forma Balance Sheet	
SCE&G Pro Forma Income Statement	

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ELECTRIC PRO FORMA ADJUSTMENTS
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

Adjustment Title: **Adjustment #6**
New Nuclear Adjustments

Allocation Method:

(1), (3), (4), (5), (6), (8), (9)	Allocated to Retail Only
(2) & (7)	Allocated Transmission Plant
(10)	Energy Sales at Generation Level

Allocation Breakdown:

		Total	Wholesale	Retail
(1) Reduction to CWIP	$	(4,835,683,443)	0	(4,835,683,443)
	%	100.00%	0.00%	100.00%
(2) Increase to Plant In Service	$	315,499,877	10,521,921	304,977,956
	%	100.00%	3.33%	96.67%
(3) Increase to Deferred Debit/Credit	$	1,953,568,934	0	1,953,568,934
	%	100.00%	0.00%	100.00%
(4) (Increase)/Decrease Revenue Related to New Nuclear	$	118,000,000	0	118,000,000
	%	100.00%	0.00%	100.00%
(5) Decrease in Other Taxes	$	(524,864)	0	(524,864)
	%	100.00%	0.00%	100.00%
(6) Increase in Amortization Expense	$	166,509,178	0	166,509,178
	%	100.00%	0.00%	100.00%
(7) Increase to Depreciation Reserve	$	7,887,497	263,048	7,624,449
	%	100.00%	3.33%	96.67%
(8) ADIT Adjustment	$	279,717,059	0	279,717,059
	%	100.00%	0.00%	100.00%
(9) Decrease in Federal Taxes	$	(17,290,000)	0	(17,290,000)
	%	100.00%	0.00%	100.00%
(10) Decrease in Fuel Inventory	$	(125,302,713)	(5,099,820)	(120,202,893)
	%	100.00%	4.07%	95.93%

Purpose of Adjustment: **Adjustment for amounts related to New Nuclear generation.**

Impact of Adjustment:

CWIP:		
NND (includes Transmission)		$4,835,683,443
Total Reduction to CWIP		**($4,835,683,443)**
Plant in Service:		
Transmission		$315,499,877
Total Increase to Plant in Service		**$315,499,877**
Regulatory Asset - NND:		$4,520,183,565
Reverse $210M Impairment		$210,000,000
Proposed Impairment		($1,400,000,000)
Total NND Regulatory Asset		$3,330,183,565
Amortization - 20 years		($166,509,178)
Subtotal		$3,163,674,387
Tax Effect		0.6175
Total Increase to Deferred Debit/Credit		**$1,953,568,934**
Revenue:		
Revenue Reduction (5%)		($118,000,000)
Total (Increase)/Decrease Revenue Related to New Nuclear		**$118,000,000**
Gross Receipts and PSC Support Tax		0.004448
Increase (Decrease) in Other Taxes		**($524,864)**
State Tax @ 5%		($5,873,757)
Federal Tax ((Margin - State Tax) @ 35%)		($39,060,483)
Net Impact of Adjustment		$72,540,896
Increase (Decrease) Amortization Expense		**$166,509,178**
State Tax @ 5%		($8,325,459)
Federal Tax ((Margin - State Tax) @ 35%)		($55,364,302)
Net Impact of Adjustment		$102,819,418
Annual Depreciation: (PIS above x Depreciation Rate)		
Transmission (2.5% depreciation rate)		$7,887,497
Total Increase to Depreciation Reserve		**$7,887,497**
Remove ADIT Capitalized Interest Adjustment (in rates)		($42,761,000)
Remove ADIT Capitalized Interest Adjustment		($306,585,400)
NOL related to Abandonment		$629,063,459
Total ADIT Adjustment		**$279,717,059**
Tax Reform Impact of 1.5% Revenue Reduction:		
5% Revenue Reduction - Dominion Proposal	$	(118,000,000)
3.5% Revenue Reduction - SCE&G Proposal	$	(90,000,000)
Variance (1.5%)	$	(28,000,000)
Tax Rate		0.3825
Taxes	$	(10,710,000)
Net Revenue Impact		(17,290,000)
Increase (Decrease) Federal Taxes	**$**	**(17,290,000)**
Remove New Nuclear Fuel:		
Unit 2 Nuclear Fuel (12 mth avg)	$	73,209,414
Unit 3 Nuclear Fuel (12 mth avg)		52,093,299
Increase (Decrease) Fuel Inventory	**$**	**(125,302,713)**

	A	B	C	D	E	F	G	H
1	**SCE&G**							
2	**Revenues for 12 Months Ending:**		**September 30, 2017**					
3								
4	Per Current Electric Earnings Statement							
5								
6			Books	Quarterly Total Electric	Quarterly Retail Electric	Adjust. To Total Rev.	Adjust. To Retail Rev.	Total Rev. as Adjusted
7	Residential	*	1,133,041,133.78					
8	Commercial	*	844,647,437.36					
9	Industrial	*	443,396,444.18					
10	Street Lighting	*	14,944,330.59					
11	Other Public Authorities	*	47,208,935.59					
12	Sales for Resale - Municipal		44,376,389.50					
13	Sales for Resale - Nonassoc	*	0.00					
14	Sales for Resale - Interchg Del		620,501.96					
15	Over/Under Recovery	*	59,496,180.99					
16	Total Electric Sales		$ 2,587,731,353.95					
17					Reverse sign of Whl Over/Under to remove			
18	**SALES REVENUES**			**$ 2,587,110,851.99**	**$ 2,540,503,608.30**	**$ -**	**$ -**	**$ 2,587,110,851.99**
19					Allocator - POO			
20	Total Other Operating Revenue	*	$ 38,993,674.16					
21								
22	**OTHER REVENUES**			**$ 39,614,176.12**	**$ 33,321,702.08**	**$ -**	**$ -**	**$ 39,614,176.12**
23					Allocators - E10 & POO			
24	Total Operating Revenues (Check)	*	**$ 2,626,725,028.11**	**$ 2,626,725,028.11**	**$ 2,573,825,310.38**			
25								
26								

Important 12 Month Revenue Numbers:

From Sales Summary - Retail Electric Accounting Group

Months		Other Municipalities	NMST - Long Term Municipalities	Interchange Delivered NMST - Short Term	Interruptible	Special Contracts Interruptible**
October, 2016		$ 77,423.38	$ 3,127,203.90	$ -	$ -	
November, 2016		$ 78,402.62	$ 3,203,632.68	$ -	$ -	
December, 2016		$ 109,800.91	$ 3,462,015.30	$ 559,345.81	$ -	
January, 2017		$ 134,707.02	$ 3,479,562.81	$ -	$ -	
February, 2017		$ 91,948.00	$ 3,087,683.58	$ 1,259.74	$ -	
March, 2017		$ 105,076.30	$ 3,397,592.57	$ -	$ -	
April, 2017		$ 81,851.54	$ 3,204,515.76	$ -	$ -	
May, 2017		$ 105,738.63	$ 3,742,867.31	$ -	$ -	
June, 2017		$ 106,602.84	$ 4,034,003.27	$ 59,896.41	$ -	
July, 2017	*	$ 102,069.52	$ 4,338,916.74	$ -	$ -	
August, 2017	*	$ 103,336.81	$ 4,325,484.51	$ -	$ -	
September, 2017	*	$ 92,636.95	$ 3,783,316.55	$ -	$ -	
		$ 1,189,594.52	$ 43,186,794.98	$ 620,501.96	$ 17,373,203.40	$ 33,902,906.38

** Special Contracts for Interruptible consist of International Paper, Finn Chem USA, Inc. & CMC Steel SC

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6	Retail Rev. as Adjusted
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18	**$ 2,540,503,608.30**
19	
20	
21	
22	**$ 33,321,702.08**
23	
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SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books ($000's)	Pro-Forma Adjustments ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)
1	Operating Revenues	2,626,725,028	(16,307,817)
2	Operating Expenses		
3	O&M Expenses - Fuel	649,424,435	-
4	O&M Expenses - Other	598,179,439	4,840,606
5	Depreciation & Amortization Expenses	274,006,765	169,044,100
6	Taxes Other Than Income	210,682,693	5,987,155
7	Total Income Taxes	194,685,466	(63,666,801)
8	Total Operating Expenses	1,926,978,798	116,205,060
9	Operating Return	699,746,230	(132,512,877)
10	Customer Growth	3,329,938	(625,263)
11	Interest on Customer Deposits	(1,114,066)	-
12	Return	701,962,102	(133,138,140)
13	Rate Base		
14	Plant in Service	9,847,762,591	309,945,931
15	Reserve for Depreciation	3,865,657,956	8,553,861
16	Net Plant	5,982,104,635	301,392,070
17	Construction Work in Progress	5,044,195,701	(4,835,688,277)
18	Deferred Debits / Credits	10,207,489	1,516,588,388
19	Total Working Capital	20,431,080	7,227,847
20	Materials & Supplies	437,304,695	(110,422,518)
21	Accumulated Deferred Income Taxes	(1,168,308,900)	446,869,559
22	Total Rate Base	10,325,934,700	(2,674,032,931)
23	Rate of Return	6.80%	

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books ($000's)	Pro-Forma Adjustments ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)
1	Operating Revenues	2,573,825,310	(16,307,817)
2	Operating Expenses		
3	O&M Expenses - Fuel	623,287,164	-
4	O&M Expenses - Other	583,711,611	4,392,040
5	Depreciation & Amortization Expenses	267,744,349	168,999,884
6	Taxes Other Than Income	206,069,444	5,853,628
7	Total Income Taxes	189,028,533	(63,366,097)
8	Total Operating Expenses	1,869,841,101	115,879,455
9	Operating Return	703,984,209	(132,187,272)
10	Customer Growth	3,329,938	(625,263)
11	Interest on Customer Deposits	(1,114,066)	-
12	Return	706,200,081	(132,812,535)
13	Rate Base		
14	Plant in Service	9,642,974,430	299,539,492
15	Reserve for Depreciation	3,777,308,466	8,289,303
16	Net Plant	5,865,665,964	291,250,189
17	Construction Work in Progress	4,885,050,807	(4,835,688,162)
18	Deferred Debits / Credits	9,547,089	1,516,587,862
19	Total Working Capital	17,474,474	7,171,777
20	Materials & Supplies	422,196,596	(105,928,322)
21	Accumulated Deferred Income Taxes	(1,144,013,449)	446,869,559
22	Total Rate Base	10,055,921,481	(2,679,737,097)
23	Rate of Return	7.02%	

Total As Adjusted
(Col. 4)
2,610,417,211
649,424,435
603,020,045
443,050,865
216,669,848
131,018,665
2,043,183,858
567,233,353
2,704,675
(1,114,066)
568,823,962
10,157,708,522
3,874,211,817
6,283,496,705
208,507,424
1,526,795,877
27,658,927
326,882,177
(721,439,341)
7,651,901,769
7.43%

Total As Adjusted
(Col. 4)
2,557,517,493
623,287,164
588,103,651
436,744,233
211,923,072
125,662,436
1,985,720,556
571,796,937
2,704,675
(1,114,066)
573,387,546
9,942,513,922
3,785,597,769
6,156,916,153
49,362,645
1,526,134,951
24,646,251
316,268,274
(697,143,890)
7,376,184,384
7.77%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)	
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments
	(Col. 1)	(Col. 2)	(Col. 3)
1	Operating Revenues	2,626,725,028	(126,307,817)
2	Operating Expenses		
3	O&M Expenses - Fuel	649,424,435	-
4	O&M Expenses - Other	598,179,439	4,840,606
5	Depreciation & Amortization Expenses	274,006,765	65,447,979
6	Taxes Other Than Income	210,682,693	5,497,875
7	Total Income Taxes	194,685,466	(56,038,588)
8	Total Operating Expenses	1,926,978,798	19,747,872
9	Operating Return	699,746,230	(146,055,689)
10	Customer Growth	3,433,501	(711,439)
11	Interest on Customer Deposits	(1,114,066)	-
12	Return	702,065,665	(146,767,128)
13	Rate Base		
14	Plant in Service	9,847,762,591	394,812,732
15	Reserve for Depreciation	3,865,657,956	10,539,769
16	Net Plant	5,982,104,635	384,272,963
17	Construction Work in Progress	5,044,195,701	(4,835,688,277)
18	Deferred Debits / Credits	10,207,489	1,903,611,263
19	Total Working Capital	20,431,080	7,227,847
20	Materials & Supplies	437,304,695	(110,422,518)
21	Accumulated Deferred Income Taxes	(1,168,308,900)	279,717,059
22	Total Rate Base	10,325,934,700	(2,371,281,663)
23	Rate of Return	6.80%	

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)	
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments
	(Col. 1)	(Col. 2)	(Col. 3)
1	Operating Revenues	2,573,825,310	(126,307,817)
2	Operating Expenses		
3	O&M Expenses - Fuel	623,287,164	-
4	O&M Expenses - Other	583,711,611	4,392,040
5	Depreciation & Amortization Expenses	267,744,349	65,403,763
6	Taxes Other Than Income	206,069,444	5,364,348
7	Total Income Taxes	189,028,533	(55,598,866)
8	Total Operating Expenses	1,869,841,101	19,561,285
9	Operating Return	703,984,209	(145,869,102)
10	Customer Growth	3,433,501	(711,439)
11	Interest on Customer Deposits	(1,114,066)	-
12	Return	706,303,644	(146,580,541)
13	Rate Base		
14	Plant in Service	9,642,974,430	381,575,985
15	Reserve for Depreciation	3,777,308,466	10,208,981
16	Net Plant	5,865,665,964	371,367,004
17	Construction Work in Progress	4,885,050,807	(4,835,688,162)
18	Deferred Debits / Credits	9,547,089	1,903,610,737
19	Total Working Capital	17,480,148	7,171,777
20	Materials & Supplies	422,196,596	(105,928,322)
21	Accumulated Deferred Income Taxes	(1,144,013,449)	279,717,059
22	Total Rate Base	10,055,927,155	(2,379,749,907)
23	Rate of Return	7.02%	

Total As Adjusted
(Col. 4)
2,500,417,211
649,424,435
603,020,045
339,454,744
216,180,568
138,646,878
1,946,726,670
553,690,541
2,722,062
(1,114,066)
555,298,537
10,242,575,323
3,876,197,725
6,366,377,598
208,507,424
1,913,818,752
27,658,927
326,882,177
(888,591,841)
7,954,653,037
6.98%

Total As Adjusted
(Col. 4)
2,447,517,493
623,287,164
588,103,651
333,148,112
211,433,792
133,429,667
1,889,402,386
558,115,107
2,722,062
(1,114,066)
559,723,103
10,024,550,415
3,787,517,447
6,237,032,968
49,362,645
1,913,157,826
24,651,925
316,268,274
(864,296,390)
7,676,177,248
7.29%

	A	B	C	D	E	F	G	H
1	**SCE&G**							
2	**Revenues for 12 Months Ending:**		**September 30, 2017**					
3								
4	Per Current Electric Earnings Statement							
5								
6			Books	Quarterly Total Electric	Quarterly Retail Electric	Adjust. To Total Rev.	Adjust. To Retail Rev.	Total Rev. as Adjusted
7	Residential	*	1,133,041,133.78					
8	Commercial	*	844,647,437.36					
9	Industrial	*	443,396,444.18					
10	Street Lighting	*	14,944,330.59					
11	Other Public Authorities	*	47,208,935.59					
12	Sales for Resale - Municipal		44,376,389.50					
13	Sales for Resale - Nonassoc	*	0.00					
14	Sales for Resale - Interchg Del		620,501.96					
15	Over/Under Recovery	*	59,496,180.99					
16	Total Electric Sales		$ 2,587,731,353.95					
17					Reverse sign of Whl Over/Under to remove			
18	**SALES REVENUES**			**$ 2,587,110,851.99**	**$ 2,540,503,608.30**	**$ -**	**$ -**	**$ 2,587,110,851.99**
19					Allocator - POO			
20	Total Other Operating Revenue	*	$ 38,993,674.16					
21								
22	**OTHER REVENUES**			**$ 39,614,176.12**	**$ 33,321,702.08**	**$ -**	**$ -**	**$ 39,614,176.12**
23					Allocators - E10 & POO			
24	Total Operating Revenues (Check)	*	**$ 2,626,725,028.11**	**$ 2,626,725,028.11**	**$ 2,573,825,310.38**			
25								
26								

	A	B	C	D	E	F	G	H
27	Important 12 Month Revenue Numbers:							
28								
29	From Sales Summary - Retail Electric Accounting Group							
30								
31			Other	NMST - Long Term	Interchange Delivered		Special Contracts	
32	Months		Municipalities	Municipalities	NMST - Short Term	Interruptible	Interruptible**	
33	October, 2016		$ 77,423.38	$ 3,127,203.90	$ -	$ -		
34	November, 2016		$ 78,402.62	$ 3,203,632.68	$ -	$ -		
35	December, 2016		$ 109,800.91	$ 3,462,015.30	$ 559,345.81	$ -		
36	January, 2017		$ 134,707.02	$ 3,479,562.81	$ -	$ -		
37	February, 2017		$ 91,948.00	$ 3,087,683.58	$ 1,259.74	$ -		
38	March, 2017		$ 105,076.30	$ 3,397,592.57	$ -	$ -		
39	April, 2017		$ 81,851.54	$ 3,204,515.76	$ -	$ -		
40	May, 2017		$ 105,738.63	$ 3,742,867.31	$ -	$ -		
41	June, 2017		$ 106,602.84	$ 4,034,003.27	$ 59,896.41	$ -		
42	July, 2017	*	$ 102,069.52	$ 4,338,916.74	$ -	$ -		
43	August, 2017	*	$ 103,336.81	$ 4,325,484.51	$ -	$ -		
44	September, 2017	*	$ 92,636.95	$ 3,783,316.55	$ -	$ -		
45			$ 1,189,594.52	$ 43,186,794.98	$ 620,501.96	$ 17,373,203.40	$ 33,902,906.38	
46								
47	** Special Contracts for Interruptible consist of International Paper, Finn Chem USA, Inc. & CMC Steel SC							
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6	Retail Rev. as Adjusted
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18	**$ 2,540,503,608.30**
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22	**$ 33,321,702.08**
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SOUTH CAROLINA ELECTRIC & GAS COMPANY
ELECTRIC PRO-FORMA & RATE BASE ADJUSTMENTS
NO MERGER BENEFITS PLAN
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ NO.	ADJUSTMENT TITLE
	Pro Form Adjustments
1	Annualize Wages, Benefits and Payroll Taxes
2	Incentive Compensation Adjustment
3	Annualize Health Care
4	Remove Employee Clubs Investment and Expenses
5	Property Retirements
6	Adjust for New Nuclear Generation Amounts
7	CWIP
8	Annualize Depreciation Based on Current Rates
9	Adjust Property Taxes
10	Annualize Insurance Expense
11	OPEB
12	Tax Effect of Annualized Interest
13	Remove Demand Side Management
14	Fuel Inventory Adjustment
15	Working Cash

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ELECTRIC PRO-FORMA & RATE BASE ADJUSTMENTS
BASE REQUEST
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ NO.	ADJUSTMENT TITLE
	Pro Form Adjustments
1	Annualize Wages, Benefits and Payroll Taxes
2	Incentive Compensation Adjustment
3	Annualize Health Care
4	Remove Employee Clubs Investment and Expenses
5	Property Retirements
6	Adjust for New Nuclear Generation Amounts
7	CWIP
8	Annualize Depreciation Based on Current Rates
9	Adjust Property Taxes
10	Annualize Insurance Expense
11	OPEB
12	Tax Effect of Annualized Interest
13	Remove Demand Side Management
14	Amortize Swap Loss Deferral
15	Amortize New Nuclear Capitalized Interest ADIT Carry Costs
16	Fuel Inventory Adjustment
17	Working Cash

	A	B	C	D	E	F	G	H
1	SCE&G							
2	Revenues for 12 Months Ending:		September 30, 2017					
3								
4	Per Current Electric Earnings Statement							
5								
6			Books	Quarterly Total Electric	Quarterly Retail Electric	Adjust. To Total Rev.	Adjust. To Retail Rev.	Total Rev. as Adjusted
7	Residential	*	1,133,041,133.78					
8	Commercial	*	844,647,437.36					
9	Industrial	*	443,396,444.18					
10	Street Lighting	*	14,944,330.59					
11	Other Public Authorities	*	47,208,935.59					
12	Sales for Resale - Municipal		44,376,389.50					
13	Sales for Resale - Nonassoc	*	0.00					
14	Sales for Resale - Interchg Del		620,501.96					
15	Over/Under Recovery	*	59,496,180.99					
16	Total Electric Sales		$ 2,587,731,353.95					
17					Reverse sign of Whl Over/Under to remove			
18	SALES REVENUES			$ 2,587,110,851.99	$ 2,540,503,608.30	$ -	$ -	$ 2,587,110,851.99
19					Allocator - POO			
20	Total Other Operating Revenue	*	$ 38,993,674.16					
21								
22	OTHER REVENUES			$ 39,614,176.12	$ 33,321,702.08	$ -	$ -	$ 39,614,176.12
23					Allocators - E10 & POO			
24	Total Operating Revenues (Check)	*	$ 2,626,725,028.11	$ 2,626,725,028.11	$ 2,573,825,310.38			
25								
26								

	A	B	C	D	E	F	G	H
27	Important 12 Month Revenue Numbers:							
28								
29	From Sales Summary - Retail Electric Accounting Group							
30								
31			Other	NMST - Long Term	Interchange Delivered		Special Contracts	
32	Months		Municipalities	Municipalities	NMST - Short Term	Interruptible	Interruptible**	
33	October, 2016		$ 77,423.38	$ 3,127,203.90	$ -	$ -		
34	November, 2016		$ 78,402.62	$ 3,203,632.68	$ -	$ -		
35	December, 2016		$ 109,800.91	$ 3,462,015.30	$ 559,345.81	$ -		
36	January, 2017		$ 134,707.02	$ 3,479,562.81	$ -	$ -		
37	February, 2017		$ 91,948.00	$ 3,087,683.58	$ 1,259.74	$ -		
38	March, 2017		$ 105,076.30	$ 3,397,592.57	$ -	$ -		
39	April, 2017		$ 81,851.54	$ 3,204,515.76	$ -	$ -		
40	May, 2017		$ 105,738.63	$ 3,742,867.31	$ -	$ -		
41	June, 2017		$ 106,602.84	$ 4,034,003.27	$ 59,896.41	$ -		
42	July, 2017	*	$ 102,069.52	$ 4,338,916.74	$ -	$ -		
43	August, 2017	*	$ 103,336.81	$ 4,325,484.51	$ -	$ -		
44	September, 2017	*	$ 92,636.95	$ 3,783,316.55	$ -	$ -		
45			$ 1,189,594.52	$ 43,186,794.98	$ 620,501.96	$ 17,373,203.40	$ 33,902,906.38	
46								
47	** Special Contracts for Interruptible consist of International Paper, Finn Chem USA, Inc. & CMC Steel SC							
48								

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6	Retail Rev. as Adjusted
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SOUTH CAROLINA ELECTRIC & GAS COMPANY
MATERIALS AND SUPPLIES - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
		($000's)			
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Fuel Stock				
1	Nuclear	258,391,568	(125,302,713)	133,088,855	127,672,138
2	Fossil	43,119,770	14,880,195	57,999,965	55,639,366
3	Total Fuel Stock	301,511,338	(110,422,518)	191,088,820	183,311,504
4	Emission Allowances	638,559	-	638,559	612,570
5	Other Electric Materials and Supplies	135,154,798	-	135,154,798	132,344,200
6	Total	437,304,695	(110,422,518)	326,882,177	316,268,274

DEFERRED DEBITS / CREDITS - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
7	Environmental	(370,500)	-	(370,500)	(360,119)
8	Wateree Scrubber Deferral	15,041,992	-	15,041,992	14,565,160
9	FASB 106	(104,231,832)	19,454	(104,212,378)	(101,398,645)
10	Pension Deferral	32,857,618	-	32,857,618	31,970,463
11	Canadys Retirement	66,910,211	-	66,910,211	64,789,157
12	New Nuclear Abandonment	-	2,200,115,309	2,200,115,309	2,200,115,309
13	Total	10,207,489	2,200,134,763	2,210,342,252	2,209,681,326

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books ($000's)	Pro-Forma Adjustments ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)
1	Operating Revenues	2,626,725,028	(420,836,831)
2	Operating Expenses		
3	O&M Expenses - Fuel	649,424,435	-
4	O&M Expenses - Other	598,179,439	4,840,606
5	Depreciation & Amortization Expenses	274,006,765	2,534,922
6	Taxes Other Than Income	210,682,693	4,187,810
7	Total Income Taxes	194,685,466	(157,375,720)
8	Total Operating Expenses	1,926,978,798	(145,812,382)
9	Operating Return	699,746,230	(275,024,449)
10	Customer Growth	3,401,421	(1,325,825)
11	Interest on Customer Deposits	(1,114,066)	-
12	Return	702,033,585	(276,350,274)
13	Rate Base		
14	Plant in Service	9,847,762,591	(5,553,946)
15	Reserve for Depreciation	3,865,657,956	666,364
16	Net Plant	5,982,104,635	(6,220,310)
17	Construction Work in Progress	5,044,195,701	209,995,166
18	Deferred Debits / Credits	10,207,489	19,454
19	Total Working Capital	20,431,080	605,075
20	Materials & Supplies	437,304,695	14,880,195
21	Accumulated Deferred Income Taxes	(1,168,308,900)	(847,614,600)
22	Total Rate Base	10,325,934,700	(628,335,020)
23	Rate of Return	6.80%	

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books ($000's)	Pro-Forma Adjustments ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)
1	Operating Revenues	2,573,825,310	(420,836,831)
2	Operating Expenses		
3	O&M Expenses - Fuel	623,287,164	-
4	O&M Expenses - Other	583,711,611	4,392,040
5	Depreciation & Amortization Expenses	267,744,349	2,490,706
6	Taxes Other Than Income	206,069,444	4,054,283
7	Total Income Taxes	189,028,533	(157,370,941)
8	Total Operating Expenses	1,869,841,101	(146,433,912)
9	Operating Return	703,984,209	(274,402,919)
10	Customer Growth	3,401,421	(1,325,825)
11	Interest on Customer Deposits	(1,114,066)	-
12	Return	706,271,564	(275,728,744)
13	Rate Base		
14	Plant in Service	9,642,974,430	(5,438,464)
15	Reserve for Depreciation	3,777,308,466	664,854
16	Net Plant	5,865,665,964	(6,103,318)
17	Construction Work in Progress	4,885,050,807	203,338,281
18	Deferred Debits / Credits	9,547,089	18,928
19	Total Working Capital	17,473,050	549,005
20	Materials & Supplies	422,196,596	14,274,571
21	Accumulated Deferred Income Taxes	(1,144,013,449)	(820,745,217)
22	Total Rate Base	10,055,920,057	(608,667,750)
23	Rate of Return	7.02%	

Total As Adjusted
(Col. 4)
2,205,888,197
649,424,435
603,020,045
276,541,687
214,870,503
37,309,746
1,781,166,416
424,721,781
2,075,596
(1,114,066)
425,683,311
9,842,208,644
3,866,324,320
5,975,884,324
5,254,190,867
10,226,943
21,036,155
452,184,890
(2,015,923,500)
9,697,599,679
4.39%

Total As Adjusted
(Col. 4)
2,152,988,479
623,287,164
588,103,651
270,235,055
210,123,727
31,657,592
1,723,407,189
429,581,290
2,075,596
(1,114,066)
430,542,820
9,637,535,966
3,777,973,320
5,859,562,646
5,088,389,088
9,566,017
18,022,055
436,471,167
(1,964,758,666)
9,447,252,307
4.56%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ELECTRIC PRO FORMA ADJUSTMENTS
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

Adjustment Title:	**Adjustment #6** **New Nuclear Adjustments**
Allocation Method:	**(1) Allocated Production Plant** **(2) & (3) Allocated to Retail Only** **(4) Allocated Production Plant**

Allocation Breakdown:

		Total	Wholesale	Retail
(1) Reduction to CWIP	**$**	0	0	0
	%	100.00%	3.39%	96.61%
(2) Reduction to Revenue	**$**	384,529,014	0	384,529,014
	%	100.00%	0.00%	100.00%
(3) Reduction to Other Taxes (Gross Receipts)	**$**	(1,710,385)	(200,000)	(1,710,385)
	%	100.00%	11.69%	100.00%

Purpose of Adjustment: **Adjustment for amounts related to New Nuclear generation.**

Impact of Adjustment:

CWIP:	
NND (includes Transmission)	$4,835,683,443
Reverse $210m Impairment	$210,000,000
Total Increase to CWIP	**$210,000,000**
Revenue:	
(Increase)/Decrease Revenue for BLRA (Non-transmission related)	$402,026,648
(Increase)/Decrease Revenue for NND ADIT carrying costs	($17,497,634)
Total (Increase)/Decrease Revenue Related to New Nuclear	**$384,529,014**
Gross Receipts and PSC Support Tax	0.004448
Increase (Decrease) in Other Taxes	**($1,710,385)**
State Tax @ 5%	($19,140,931)
Federal Tax ((Margin - State Tax) @ 35%)	($127,287,194)
Net Impact of Adjustment	$236,390,503
ADIT Capitalized Interest Adjustment	($306,585,400)
ADIT Adjustment - 174 ADIT	($541,029,200)
Total ADIT Adjustment	**($847,614,600)**

	A	B	C	D	E	F
1	**SCE&G**					
2	**Taxes for 12 Months Ending:**		**September 30, 2017**			
3						
4	**SCEG & SCFC State Income Tax Accrual (Year Ended . . .)**					
5						
6	Description of Adjustment	Code	Electric Amount			
7	Interest Expense	TD2	$ 285,788,623	*	$ 246,416,868	*
8	Reacquired Debt Adjts.	TD5	$ (1,056,021)	*		
9	Book Depreciation & Amort.	TD3	$ (278,112,980)	*		
10	Book Expense Nuc. Fuel	TD4	$ (44,981,358)	*		
11	Tax Depr. Nuc. Fuel	TD3	$ 42,668,433	*		
12	Est Tax Overhead for AFUDC- Nuclear	TD4	$ (273,761,541)	*		
13	Tax Depreciation Adj-Repairs Exp	TD3	$ 49,975,186	*		
14	Deferred Fuel	TD9	$ 57,125,936	*		
15	Nuclear Decommissioning	TD1	$ (3,224,921)	*		
16	Tax Depreciation - Per System	TD3	$ 309,166,151	*		
17	Closed Non Hedges	TD9	$ -	*		
18	Tax Depr Adj-174 Out of System	TD3	$ 241,321,756	*		
19	Removal Cost-Pre 81 Only all else in sys	TD5	$ 10,846,413	*		
20	Fuel Clause Wholesale	TD1	$ -	*		
21	Book Depr & Amort. SCANA Serv	TD3	$ 11,451,401	*		
22	Estimated Tax Overhead for AFUDC	TD1	$ -	*		
23	Storm Damage Book Accrual	TD5	$ 23,607,305	*		
24	AFUDC- Debt per income statement	TD1	$ 13,361,273	*		
25	Tax Depr Adj-481A Retirement Out of Sys	TD3	$ -	*		
26	Tax Depr Additional	TD3	$ 26,729,572	*		
27	Non Taxable Revenue	TD7	$ 41,039,970	*		
28	Nuclear Refueling	TD4	$ (15,580,797)	*		
29	Pension Expense	TD6	$ (895,217)	*		
30	Unbilled Revenue	TD9	$ (1,757,750)	*		
31	Contr. Construction	TD5	$ -	*		
32	Regulatory Asset-Asset Environmental	TD1	$ (3,162,856)	*		
33	Palmetto Ctr. Lease Litigation	TD5	$ -	*		
34	Book Depr. Chgd. Oper.	TD3	$ (1,200,174)	*		
35	Other Post Retire Benefits	TD6	$ (3,620,647)	*		
36	Officers 162 M Limitation	TD6	$ (1,802,983)	*		
37	Meals and Lobbying	TD6	$ (752,250)	*		
38	Regulatory Asset-Pollution Control	TD1	$ (1,344,598)	*		
39	Amort. Intangible Plant	TD3	$ -	*		
40	Franchise Fees	TD9	$ -	*		
41	Uncollectible Accounts	TD1	$ (275,701)	*		
42	Major Maintenance	TD1	$ 5,521,170	*		
43	Unearned Revenue	TD1		*		
44	Elec Demand Side Mgt	TD9	$ (519,610)	*		
45	Environmental Clean-Up	TD5	$ (2,376)	*		
46	Early Retirement Program	TD6	$ 1,558,958	*		
47	Cybersecurity	TD1	$ 7,317,071	*		
48	Vacation Accrual	TD6	$ 503,113	*		
49	Vacation Carryover	TD6	$ -	*		
50	Prepayment Acceleration	TD9	$ 2,421,315	*		
51	Toshiba Settlement	TD1	$ (1,095,230,291)	*		

	A	B	C	D	E	F
52	NO2 Emission Allowances	TD1	$ -	*		
53	Long Term Disability	TD6	$ 797,117	*		
54	Research & Experimentation	TD5	$ -	*		
55	Injuries & Damages	TD6	$ (2,372,195)	*		
56	Research Project Fee	TD5	$ 400,000	*		
57	Bonus Incentive Plan	TD6	$ -	*		
58	Emission Allowance	TD1	$ -	*		
59	VCS Cost	TD1	$ (183,816)	*		
60	Reg Asset Recovery Capacity	TD1	$ (296,000)	*		
61	JAD Termination	TD1	$ (1,200,000)	*		
62	Total Adjustments (Check) →		$ (885,521,942)	*	$ 285,788,623	*
63						
64	Synfuel Tax Credits					
65	Jobs Tax Credit		$ (1,925,000)	*		
66	State Investment Tax Credits (ITC)- SCFC		$ -	*		
67	State Investment Tax Credits (ITC)		$ (3,560,600)	*		
68						
69	Total Prior Year Adjustments		$ (1,328)	*		
70						
71	**SCEG & SCFC Federal Income Tax Accrual (Year Ended . . .)**					
72						
73	Description of Adjustment	Code	Electric Amount	*		
74	State Inc Tax Deduction		$ 69,222,651	*		
75	Interest Expense	TD2	$ 285,788,623	*	$ 246,416,868	*
76	Reacquired Debt Adjts.	TD5	$ (1,056,021)	*		
77	Book Depreciation & Amort.	TD3	$ (278,112,980)	*		
78	Book Expense Nuc. Fuel	TD4	$ (44,981,358)	*		
79	Tax Depr. Nuc. Fuel	TD3	$ 42,668,433	*		
80	Est Tax Overhead for AFUDC-Nuclear	TD4	$ (273,761,541)	*		
81	Tax Depreciation Adj-Repairs Exp	TD3	$ 49,975,186	*		
82	Deferred Fuel	TD9	$ 57,125,936	*		
83	Nuclear Decommissioning	TD1	$ (3,224,921)	*		
84	Tax Depreciation - Per System	TD3	$ 399,888,539	*		
85	Closed Non Hedges	TD9	$ -	*		
86	Tax Depr Adj-174 Out of Systm	TD3	$ 238,877,470	*		
87	Removal Cost-Pre 81 Only All Else in Sys	TD5	$ 10,846,413	*		
88	Fuel Clause Wholesale	TD1	$ -	*		
89	Book Depr & Amort. SCANA Serv	TD3	$ 11,451,401	*		
90	Estimated Tax Overhead for AFUDC	TD1	$ -	*		
91	Storm Damage Book Accrual	TD5	$ 23,607,305	*		
92	AFUDC- Debt per income statement	TD1	$ 13,361,273	*		
93	Tax Depr Adj-481A Retirement Out of Sys	TD3	$ -	*		
94	Tax Depr Additional	TD3	$ 67,149,563	*		
95	Non Taxable Revenue	TD7	$ -	*		
96	Nuclear Refueling	TD4	$ (15,580,797)	*		
97	Pension Expense	TD6	$ (895,217)	*		
98	Unbilled Revenue	TD9	$ (1,757,750)	*		
99	Contr. Construction	TD5	$ -	*		
100	Regulatory Asset-Asset Environmental	TD1	$ 12,482,244	*		
101	Other Post Retire Benefits	TD6	$ (3,620,647)	*		
102	Officers 162 M Limitation	TD6	$ (1,802,983)	*		

	A	B		C	D		E	F
103	Book Depr. Chgd. Oper.	TD3	$	(1,200,174)	*			
104	Palmetto Ctr. Lease Litigation	TD5	$	-	*			
105	Meals and Lobbying	TD6	$	(752,250)	*			
106	Regulatory Asset-Pollution Control	TD1	$	(1,344,598)	*			
107	Amort. Intangible Plant	TD3	$	-	*			
108	Franchise Fees	TD9	$	-	*			
109	Uncollectible Accounts	TD1	$	(275,701)	*			
110	Major Maintenance	TD1	$	5,521,170	*			
111	Unearned Revenue	TD1	$	-	*			
112	Ins. Prem. Dir. End. Program	-	$	-	*			
113	Manufacturer's Deduction	TD1	$	6,196,456	*			
114	Environmental Clean-Up	TD5	$	(2,376)	*			
115	Early Retirement Program	TD6	$	1,558,958	*			
116	Elec Demand Side Mgt	TD9	$	(519,610)	*			
117	Research & Experimentation	TD5	$	-	*			
118	Vacation Accrual	TD6	$	503,113	*			
119	Vacation Carry Over	TD6	$	-	*			
120	Prepayment Acceleration	TD9	$	2,421,315	*			
121	Toshiba Settlement	TD1	$	(1,095,230,291)	*			
122	Cybersecurity	TD1	$	7,317,071	*			
123	Long Term Disability	TD6	$	797,117	*			
124	Injuries & Damages	TD6	$	(2,372,195)	*			
125	Research Project Fee	TD5	$	400,000	*			
126	Bonus Incentive Plan	TD6	$	-	*			
127	Emission Allowance	TD1	$	-	*			
128	VCS Cost	TD1	$	(183,816)	*			
129	Reg Asset Recovery Capacity	TD1	$	(296,000)	*			
130	JAD Termination	TD1	$	(1,200,000)	*			
131	Total Adjustments (Check) →		$	(706,799,613)	*	$	285,788,623	*
132	Total Prior Year Adjustments		$	(7,410,671)	*			
133								
134	Synfuel Tax Credits							
135	Research Credit		$	(5,262,495)	*			
136								
137	**SCEG Income Tax Expense (Year Ended . . .)**							
138								
139	State Deferred Taxes (Debits)	Code		Electric Amount				
140	Depreciation	P	$	10,661,100	*			
141	APOG, LLC	N	$	-	*			
142	Basis Difference	P	$	1,445,200	*			
143	Basis Difference -Nuclear	N	$	35,916,200	*			
144	Def Fuel	R	$	3,860,900	*			
145	Demand Side MGT	R	$	42,800	*			
146	Injuries & Damages	P	$	-	*			
147	Uncollectible Accounts	P	$	-	*			
148	Amort. Intangible Plant	P	$	100	*			
149	Removal Cost	P	$	-	*			
150	Fin 48	P	$	273,440	*			
151	Palmetto Center Lease	P	$	-	*			
152	Other Post Retirement Ben.	P	$	-	*			
153	Environmental Clean-up	P	$	-	*			

	A	B		C	D		E	F
154	Pension Expense	P	$	-	*			
155	Deferred Capacity	P	$	311,900	*			
156	Nuclear Refueling	N	$	-	*			
157	Depr Power Plant Upgrade	P	$	-	*			
158	Gain/Loss Reacquired Debt	P	$	4,300	*			
159	Key Employee Program	P	$	74,100	*			
160	Emission Allowances	P	$	-	*			
161	Removal Cost	P	$	365,900	*			
162	NO2 Emission Allowances	P	$	7,300	*			
163	Reg Receivable Pension & 158	P	$	1,049,100	*			
164	Reg Receivable OPEB & 158	P	$	378,700	*			
165	Westinghouse Litigation	N	$	-	*			
166	Decom. & Decontam. Liab.	P	$	-	*			
167	Research & Experimentation	P	$	184,000	*			
168	Research Project Fee	P	$	-	*			
169	Grants	P	$	20,000	*			
170	Depr Research Project	P	$	-	*			
171	NOL & Credit Limitation	S	$	-	*			
172	Early Retirement	P	$	77,900	*			
173	Bonus Plan	P	$	-	*			
174	Unbilled Revenue	R	$	7,500	*			
175	Unearned Revenue	R	$	-	*			
176	Pension - SFAS 158	P	$	480,500	*			
177	OPEB - SFAS 158	P	$	169,300	*			
178	Prepayments Acceleration	R	$	121,100	*			
179	Rate Case Cost	R	$	-	*			
180	NUSTART	P	$	-	*			
181	Reg Asset Environmental	P	$	-	*			
182	Municipal Franchise Fees	R	$	-	*			
183	Storm Damage	R	$	1,180,400	*			
184	Canadys/McMeekin	P	$	50,900	*			
185	Reg Asset Wateree Scrubber	P	$	-	*			
186	JAD Termination	P	$	-	*			
187	Major Maintenance	P	$	276,100	*			
188	Burton Insurance Proceeds	P	$	-	*			
189	Vacation Accrual	P	$	44,100	*			
190	Reg Asset Recovery Capacity	P	$	-	*			
191	VCS Costs	P	$	-	*			
192	Reg Asset Pollution Control	P	$	21,400	*			
193	Long Term Disability	P	$	39,900	*	$	57,064,140	*
194								
195	Federal Deferred Taxes (Debits)	Code		Electric Amount				
196	Depreciation	P	$	101,401,000	*			
197	APOG, LLC	N	$	-	*			
198	Depr. Research Project	P	$	-	*			
199	Basis Difference	P	$	9,610,600	*			
200	Basis Difference-Nuclear	N	$	250,434,400	*			
201	Def Fuel	R	$	25,674,900	*			
202	Fin 48	P	$	8,443,000	*			
203	Injuries & Damages	P	$	-	*			
204	Removal Cost	P	$	2,432,900	*			

	A	B	C	D	E	F
205	Uncollectible Accounts	P	$ -	*		
206	Amort. Intangible Plant	P	$ -	*		
207	Demand Side MGT	R	$ 284,700	*		
208	NOL & Credit Limitation	S	$ -	*		
209	Other Post Retirement Ben.	P	$ -	*		
210	Environmental Clean-up	P	$ -	*		
211	Pension Expense	P	$ -	*		
212	Deferred Capacity	P	$ 2,074,200	*		
213	Nuclear Refueling	N	$ -	*		
214	Westinghouse Litigation	N	$ -	*		
215	Gain/Loss Reacquired Debt	P	$ 28,700	*		
216	Unbilled Revenue	R	$ -	*		
217	Key Employee Program	P	$ 493,000	*		
218	Emission Allowances	P	$ -	*		
219	NO2 Emission Allowances	P	$ 98,200	*		
220	Reg Receivable Pension	P	$ 6,977,800	*		
221	Reg Receivable OPEB	P	$ 2,415,400	*		
222	Burton Insurance Proceeds	P	$ -	*		
223	Decom. & Decontam. Liab.	P	$ -	*		
224	Research & Experimentation	P	$ 1,223,300	*		
225	Grants	P	$ 133,000	*		
226	Early Retirement	P	$ 518,400	*		
227	Bonus Plan	P	$ -	*		
228	Fuel Wholesale	P	$ -	*		
229	Reg Asset Wateree Scrubber	P	$ -	*		
230	Unearned Revenue	R	$ -	*		
231	Reg Asset Environmental	P	$ -	*		
232	Prepayments Acceleration	R	$ 805,100	*		
233	Depr Power Plant Upgrade	P	$ -	*		
234	State ITC Amort-Unbilled	P	$ -	*		
235	Rate Case Cost	R	$ -	*		
236	NUSTART	P	$ -	*		
237	Pension - SFAS 158	P	$ 3,195,600	*		
238	OPEB - SFAS 158	P	$ 1,228,400	*		
239	State ITC Amort-CIS	P	$ -	*		
240	Major Maintenance	P	$ 2,170,000	*		
241	JAD Termination	P	$ -	*		
242	Reg Asset Pollution Control	P	$ 142,300	*		
243	Storm Damage	R	$ 7,849,400	*		
244	Canadys	P	$ 4,200	*		
245	Vacation Accrual	P	$ 293,000	*		
246	Reg Asset Recovery Capacity	P	$ -	*		
247	VCS Costs	P	$ -	*		
248	State ITC Amort	P	$ -	*	$ 428,196,500	*
249	Long Term Disability	P	$ 265,000	*		
250						
251	Total Deferred Taxes (Check) →		$ 485,260,640	*		
252						
253	State Flowback Taxes (Credits)	Code	Electric Amount			
254	Depreciation Lake Murray Dam	P	$ -	*		
255	Depreciation	P	$ (4,615,400)	*		

	A	B		C	D		E	F
256	Basis Difference	P	$	(1,599,700)	*			
257	Basis Difference-Nuclear	N	$	(15,020,200)	*			
258	Amort. Intangible Plant	P	$	(68,500)	*			
259	Def Fuel	R	$	(1,004,400)	*			
260	Pension Expense	P	$	(1,029,800)	*			
261	Reg Asset Environmental	P	$	(4,700)	*			
262	Amended Returns	P	$	-	*			
263	Environmental Clean-up	P	$	(100)	*			
264	Elec Demand Side Mgt	R	$	(68,800)	*			
265	Unbilled Revenue	R	$	(4,500)	*			
266	Loss Reacquired Debt	P	$	(57,100)	*			
267	Nuclear Decom.	N	$	(161,244)	*			
268	Long Term Disability	P	$	(5,300)	*			
269	Def Capacity	P	$	-	*			
270	Toshiba Settlement	P	$	(54,761,500)	*			
271	Unearned Revenue	R	$	(95,400)	*			
272	Uncollectible Accounts	P	$	(16,000)	*			
273	Storm Damages	R	$	-	*			
274	Nuclear Refueling	N	$	(779,000)	*			
275	NOL & Credit Limitation	S	$	-	*			
276	Reg Asset Recovery Capacity	P	$	(14,800)	*			
277	Bonus Plan	P	$	(124,700)	*			
278	Injuries & Damages	P	$	(118,600)	*			
279	Decom & Decontam Liab.	P	$	-	*			
280	Other Post Retirement Ben.	P	$	(184,000)	*			
281	Early Retirement	P	$	(68,000)	*			
282	Rate Case Cost	R	$	-	*			
283	Pension - SFAS 158	P	$	(1,049,100)	*			
284	OPEB - SFAS 158	P	$	(378,700)	*			
285	Canadys	P	$	(537,000)	*			
286	FIN 48	P	$	(19,748,685)	*			
287	Depr Power Plant Upgrade	P	$	-	*			
288	NO2 Emission Allowances	P	$	-	*			
289	Emission Allowances	P	$	(400)	*			
290	VCS Costs	P	$	(9,200)	*			
291	NUSTART	P	$	-	*			
292	Fuel Wholesale	P	$	-	*			
293	Vacation Accrual	P	$	(11,200)	*			
294	Reg Asset Pollution Control	P	$	(67,200)	*			
295	Deprec Research Project	P	$	(227,900)	*			
296	Reg Receivable Pension & 158	P	$	(480,500)	*			
297	JAD Termination	P	$	(60,000)	*			
298	Non-Hedges	R	$	-	*			
299	Reg Receivable OPEB & 158	P	$	(169,300)	*	$	(102,540,929)	*
300								
301	Federal Flowback Taxes (Credits)	Code		Electric Amount				
302	Depreciation	P	$	(32,005,300)	*			
303	Non-Hedges	R	$	-	*			
304	Basis Difference	P	$	(10,670,500)	*			
305	Basis Difference-Nuclear	N	$	(111,489,100)	*			
306	State Invest. Tax Credit	P	$	-	*			

	A	B	C	D	E	F
307	Amort. Intangible Plant	P	$ (451,500)	*		
308	Def Fuel	R	$ (6,679,100)	*		
309	Pension Expense	P	$ (6,847,700)	*		
310	NOL & Credit Limitation	S	$ -	*		
311	Depreciation Fin 48	P	$ (137,946,000)	*		
312	Reg Receivable OPEB	P	$ (1,228,400)	*		
313	Key Employee	P	$ -	*		
314	Unbilled Revenue	R	$ -	*		
315	Loss Reacquired Debt	P	$ (379,800)	*		
316	Nuclear Decom.	N	$ (1,072,284)	*		
317	Long Term Disability	P	$ (35,500)	*		
318	Palmetto Center Lease	P	$ -	*		
319	Reg Asset Recovery Capacity	P	$ (98,400)	*		
320	Toshiba Settlement	P	$ (364,164,100)	*		
321	Uncollectible Accounts	P	$ (106,500)	*		
322	Storm Damages	R	$ -	*		
323	Unearned Revenue	R	$ -	*		
324	Rate Case Cost	R	$ -	*		
325	State ITC Amort-Unbilled	P	$ -	*		
326	Early Retirement	P	$ (451,900)	*		
327	JAD Termination	P	$ (399,000)	*		
328	Pension - SFAS 158	P	$ (6,977,800)	*		
329	OPEB - SFAS 158	P	$ (2,415,400)	*		
330	Bonus Plan	P	$ (829,300)	*		
331	Injuries & Damages	P	$ (788,800)	*		
332	Palmetto Center Lease-Litigation	P	$ -	*		
333	NO2 Emission Allowances	P	$ (634,100)	*		
334	Emission Allowances	P	$ (2,900)	*		
335	Other Post Retirement Ben.	P	$ (1,223,600)	*		
336	Environmental Clean-up	P	$ (800)	*		
337	DSM Programs	R	$ -	*		
338	NUSTART	P	$ -	*		
339	Fuel Wholesale	P	$ -	*		
340	Prepayment Acceleration	R	$ (29,800)	*		
341	Demand Side Mgt	R	$ (457,500)	*		
342	VCS Cost	P	$ (61,100)	*		
343	Depr Research Project	P	$ -	*		
344	Research & Experiment.	P	$ (1,515,100)	*		
345	Vacation Accrual	P	$ (74,800)	*		
346	Reg Asset Environmental	P	$ (31,500)	*		
347	Reg Receivable Pension	P	$ (3,195,600)	*		
348	Canadys	P	$ (3,570,800)	*		
349	Removal Cost	P	$ -	*		
350	Reg Asset Pollution Control	P	$ (447,100)	*		
351	Nuclear Refueling	N	$ (5,180,600)	*	$ (701,461,684)	*
352						
353	Total Flowback Taxes (Check) →		$ (804,002,613)	*		
354						
355	<u>Investment Tax Credit</u>		<u>Electric Amount</u>			
356	State Deferred		$ -	*		
357	State Flowback		$ -	*		

	A	B	C	D	E	F
358	Federal Deferred		$ -	*		
359	Federal Flowback		$ (1,276,100)	*		
360	Net ITC		$ (1,276,100)	*		
361	Federal Synfuel Tax Credits Deferrd/Reversed		$ -	*		
362	**SCFC Income Tax Expense (Year Ended . . .)**					
363						
364	Total Deferred Taxes		$ 71,100	*		
365	Total Flowback Taxes		$ (955,100)	*		
366						
367	**SCEG Income Tax Expense (Year-To-Date . . .)**					
368						
369	Total Deferred Taxes - Electric		$ 293,081,400	*		
370	Total Deferred Taxes - Gas		$ 15,987,200	*		
371	Total Deferred Taxes - Coach		$ -	*		
372	Total Deferred Taxes - B.L.		$ 6,046,300	*		
373	Total Flowback Taxes - Electric		$ (671,602,846)	*		
374	Total Flowback Taxes - Gas		$ (6,046,900)	*		
375	Total Flowback Taxes - Coach		$ -	*		
376	Total Flowback Taxes - B.L.		$ (78,666,900)	*		
377						
378	**SCFC Income Tax Expense (Year-To-Date . . .)**					
379						
380	Total Deferred Taxes		$ 49,800	*		
381	Total Flowback Taxes		$ 37,300	*		
382						
383	**SCEG Provision for Taxes Other Than Income**					
384						
385	Generation Tax		$ 6,902,895	*		
386	Electric Taxes Other than Income		$ 210,682,693	*		
387	Total Electric Property Taxes		$ 173,382,543	*		
388						
389						

RESPONSE NO. 1-166

	2013	2014	2015	2016
Made by SCANA or SCE&G Directly to Donee	1,584,655	4,605,341	4,142,879	2,275,949
Made by SCE&G to the Good Neighbor Fund	35,000	38,230	103,216	8,200
Made by SCE&G to the SCE&G Foundation				3,500,000
Made from SCE&G Foundation to Donee	75,000	85,000	65,000	215,000
Made by PSNC Directly to Donee	342,014	312,555	191,869	267,138
Made by SEMI Directly to Donee	356,808	401,204	335,376	378,858
	2,393,477	5,442,330	4,838,340	6,645,145

The above is a summary of activity by year. The following individual sheet provide details.

2017
2,243,262
48,071
250,000
414,854
366,933
3,323,120

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (3rd Continuing AIR)
DOCKET NO. 2017-305-E (2nd Continuing AIR)
DOCKET NO. 2017-370-E (2nd Continuing AIR)

Response No. 2-10

Beginning Basis	$ 3,635,653
Amortization	$ 72,713
Weighted Average Cost of Capital (WACC)	10.01%
Effective Tax Rate	24.95%
Retail Allocation	96.83%

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Beginning Basis		$ 3,635,653	$ 3,562,940	$ 3,490,227	$ 3,417,514	$ 3,344,801	$ 3,272,088
Amortization		$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713
Ending Basis		$ 3,562,940	$ 3,490,227	$ 3,417,514	$ 3,344,801	$ 3,272,088	$ 3,199,375
ADIT		$ (888,954)	$ (870,812)	$ (852,670)	$ (834,528)	$ (816,386)	$ (798,244)
Rate Base		$ 2,673,986	$ 2,619,415	$ 2,564,844	$ 2,510,273	$ 2,455,702	$ 2,401,131
Average Rate Base		$ 3,154,820	$ 2,646,701	$ 2,592,130	$ 2,537,559	$ 2,482,987	$ 2,428,416
Return	**$ 6,871,190**	**$ 315,686**	**$ 264,841**	**$ 259,381**	**$ 253,920**	**$ 248,459**	**$ 242,999**
Amortization	**$ 3,635,653**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**
Total Electric Revenue Requirement	**$ 10,506,843**	$ 388,399	$ 337,554	$ 332,094	$ 326,633	$ 321,172	$ 315,712
Retail Electric Revenue Requirement	**$ 10,173,776**	$ 376,087	$ 326,854	$ 321,566	$ 316,279	$ 310,991	$ 305,704

	Year 7	Year 8	Year 9	Year 10	Year 11
Beginning Basis	$ 3,199,375	$ 3,126,662	$ 3,053,949	$ 2,981,235	$ 2,908,522
Amortization	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713
Ending Basis	$ 3,126,662	$ 3,053,949	$ 2,981,235	$ 2,908,522	$ 2,835,809
ADIT	$ (780,102)	$ (761,960)	$ (743,818)	$ (725,676)	$ (707,534)
Rate Base	$ 2,346,560	$ 2,291,988	$ 2,237,417	$ 2,182,846	$ 2,128,275
Average Rate Base	$ 2,373,845	$ 2,319,274	$ 2,264,703	$ 2,210,132	$ 2,155,560
Return	**$ 237,538**	**$ 232,077**	**$ 226,617**	**$ 221,156**	**$ 215,695**
Amortization	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**
Total Electric Revenue Requirement	$ 310,251	$ 304,790	$ 299,330	$ 293,869	$ 288,409
Retail Electric Revenue Requirement	$ 300,416	$ 295,129	$ 289,841	$ 284,554	$ 279,266

Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
$ 2,835,809	$ 2,763,096	$ 2,690,383	$ 2,617,670	$ 2,544,957	$ 2,472,244	$ 2,399,531	$ 2,326,818	$ 2,254,105	$ 2,181,392	$ 2,108,679	$ 2,035,966	$ 1,963,253	$ 1,890,540	$ 1,817,827	$ 1,745,113
$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713
$ 2,763,096	$ 2,690,383	$ 2,617,670	$ 2,544,957	$ 2,472,244	$ 2,399,531	$ 2,326,818	$ 2,254,105	$ 2,181,392	$ 2,108,679	$ 2,035,966	$ 1,963,253	$ 1,890,540	$ 1,817,827	$ 1,745,113	$ 1,672,400
$ (689,393)	$ (671,251)	$ (653,109)	$ (634,967)	$ (616,825)	$ (598,683)	$ (580,541)	$ (562,399)	$ (544,257)	$ (526,115)	$ (507,973)	$ (489,832)	$ (471,690)	$ (453,548)	$ (435,406)	$ (417,264)
$ 2,073,704	$ 2,019,133	$ 1,964,561	$ 1,909,990	$ 1,855,419	$ 1,800,848	$ 1,746,277	$ 1,691,706	$ 1,637,135	$ 1,582,563	$ 1,527,992	$ 1,473,421	$ 1,418,850	$ 1,364,279	$ 1,309,708	$ 1,255,136
$ 2,100,989	$ 2,046,418	$ 1,991,847	$ 1,937,276	$ 1,882,705	$ 1,828,134	$ 1,773,562	$ 1,718,991	$ 1,664,420	$ 1,609,849	$ 1,555,278	$ 1,500,707	$ 1,446,136	$ 1,391,564	$ 1,336,993	$ 1,282,422
$ 210,235	**$ 204,774**	**$ 199,314**	**$ 193,853**	**$ 188,392**	**$ 182,932**	**$ 177,471**	**$ 172,010**	**$ 166,550**	**$ 161,089**	**$ 155,628**	**$ 150,168**	**$ 144,707**	**$ 139,246**	**$ 133,786**	**$ 128,325**
$ 72,713	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**
$ 282,948	$ 277,487	$ 272,027	$ 266,566	$ 261,105	$ 255,645	$ 250,184	$ 244,723	$ 239,263	$ 233,802	$ 228,341	$ 222,881	$ 217,420	$ 211,959	$ 206,499	$ 201,038
$ 273,978	$ 268,691	$ 263,403	$ 258,116	$ 252,828	$ 247,541	$ 242,253	$ 236,966	$ 231,678	$ 226,391	$ 221,103	$ 215,815	$ 210,528	$ 205,240	$ 199,953	$ 194,665

Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40	Year 41	Year 42	Year 43
$ 1,672,400	$ 1,599,687	$ 1,526,974	$ 1,454,261	$ 1,381,548	$ 1,308,835	$ 1,236,122	$ 1,163,409	$ 1,090,696	$ 1,017,983	$ 945,270	$ 872,557	$ 799,844	$ 727,131	$ 654,418	$ 581,704
$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713
$ 1,599,687	$ 1,526,974	$ 1,454,261	$ 1,381,548	$ 1,308,835	$ 1,236,122	$ 1,163,409	$ 1,090,696	$ 1,017,983	$ 945,270	$ 872,557	$ 799,844	$ 727,131	$ 654,418	$ 581,704	$ 508,991
$ (399,122)	$ (380,980)	$ (362,838)	$ (344,696)	$ (326,554)	$ (308,412)	$ (290,271)	$ (272,129)	$ (253,987)	$ (235,845)	$ (217,703)	$ (199,561)	$ (181,419)	$ (163,277)	$ (145,135)	$ (126,993)
$ 1,200,565	$ 1,145,994	$ 1,091,423	$ 1,036,852	$ 982,281	$ 927,710	$ 873,138	$ 818,567	$ 763,996	$ 709,425	$ 654,854	$ 600,283	$ 545,712	$ 491,140	$ 436,569	$ 381,998
$ 1,227,851	$ 1,173,280	$ 1,118,709	$ 1,064,137	$ 1,009,566	$ 954,995	$ 900,424	$ 845,853	$ 791,282	$ 736,711	$ 682,139	$ 627,568	$ 572,997	$ 518,426	$ 463,855	$ 409,284
$ 122,864	**$ 117,404**	**$ 111,943**	**$ 106,483**	**$ 101,022**	**$ 95,561**	**$ 90,101**	**$ 84,640**	**$ 79,179**	**$ 73,719**	**$ 68,258**	**$ 62,797**	**$ 57,337**	**$ 51,876**	**$ 46,415**	**$ 40,955**
$ 72,713	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**
$ 195,578	$ 190,117	$ 184,656	$ 179,196	$ 173,735	$ 168,274	$ 162,814	$ 157,353	$ 151,892	$ 146,432	$ 140,971	$ 135,510	$ 130,050	$ 124,589	$ 119,129	$ 113,668
$ 189,378	$ 184,090	$ 178,803	$ 173,515	$ 168,228	$ 162,940	$ 157,652	$ 152,365	$ 147,077	$ 141,790	$ 136,502	$ 131,215	$ 125,927	$ 120,640	$ 115,352	$ 110,065

Year 44	Year 45	Year 46	Year 47	Year 48	Year 49	Year 50
$ 508,991	$ 436,278	$ 363,565	$ 290,852	$ 218,139	$ 145,426	$ 72,713
$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713	$ 72,713
$ 436,278	$ 363,565	$ 290,852	$ 218,139	$ 145,426	$ 72,713	$ (0)
$ (108,851)	$ (90,710)	$ (72,568)	$ (54,426)	$ (36,284)	$ (18,142)	$ 0
$ 327,427	$ 272,856	$ 218,285	$ 163,713	$ 109,142	$ 54,571	$ (0)
$ 354,712	$ 300,141	$ 245,570	$ 190,999	$ 136,428	$ 81,857	$ 27,286
$ 35,494	**$ 30,034**	**$ 24,573**	**$ 19,112**	**$ 13,652**	**$ 8,191**	**$ 2,730**
$ 72,713	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**	**$ 72,713**
$ 108,207	$ 102,747	$ 97,286	$ 91,825	$ 86,365	$ 80,904	$ 75,443
$ 104,777	$ 99,490	$ 94,202	$ 88,914	$ 83,627	$ 78,339	$ 73,052